Proposal for a customised price-quality path

19 February 2013

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1.1 Introduction

Orion owns and operates the electricity distribution network servicing the Christchurch and central Canterbury region.

Our electricity distribution network is located between the Waimakariri and Rakaia rivers, and from the Canterbury coast to Arthur's Pass. Our network covers 8,000 square kilometres of diverse geography, including Christchurch city, Banks Peninsula, farming communities and high country.

Our network is fundamental to Canterbury's social and economic wellbeing. We transport electricity from 15 Transpower grid exit points to approximately 190,000 homes and businesses. Approximately 90% of our consumers are located in the urban area of Christchurch with the remaining 10% in rural areas.

The vast majority of our customers – over 85% – are residential households. The rest are commercial and industrial premises.

Business customers use around 60% of the electricity delivered via our network, while residential customers account for the other 40%. We have some 320 major business consumers with loads between 0.3MW and 5MW.

Orion's ultimate shareholders are Christchurch City Council (CCC) (89.275%) and Selwyn District Council (SDC) (10.725%).

Orion also wholly owns the electrical contracting business, Connetics Limited (Connetics). Connetics competes to construct and maintain substations, overhead and underground lines and associated equipment for Orion and other customers. Connetics also operates an equipment supply and distribution business and provides engineering design and consultancy services.

In this customised price-quality path (CPP) application, we propose to:

- continue to prudently repair and invest in our electricity distribution network
- restore the resiliency and reliability of our network to near pre-earthquake levels by 31 March 2019
- recover our uninsurable earthquake related costs and losses from consumers by way of higher network prices
- smooth the necessary higher prices over ten years, commencing on 1 April 2014, so as to reduce rate shock for consumers.

We believe that our CPP proposals are:

- prudent and efficient
- in the long term interests of consumers
- consistent with feedback we have received from consumers over a number of years
- consistent with post-earthquake consumer feedback, including the feedback we received on our draft CPP proposals in November and December 2012
- consistent with the section 52A purpose statement in Part 4 of the Commerce Act (the Act)

- in compliance with the Commerce Commission's (the Commission's) input methodologies (IMs).

1.1.1 Canterbury earthquakes

On 4 September 2010 Canterbury was hit by a 7.1 magnitude earthquake. The earthquake had an epicentre near Darfield, about 40km west of Christchurch City. There were no fatalities as a result of this earthquake but there was widespread damage to local infrastructure and buildings. The eastern suburbs of Christchurch and the Kaiapoi township were seriously affected by liquefaction and lateral ground movement.

An aftershock sequence of more than 12,000 aftershocks of varying magnitude began that day and the sequence is ongoing. All of the earthquakes experienced since are the result of ruptures on faults not known to be active prior to September 2010.

Major earthquakes followed, the most notable being the deadly and devastating 6.3 magnitude earthquake on 22 February 2011 that struck near Lyttelton on the Port Hills, the 5.7 and 6.3 magnitude earthquakes of 13 June 2011, and the 5.8 and 6.0 magnitude earthquakes of 23 December 2011.

The event on 22 February 2011 was by far the most serious, resulting in 185 deaths.

In the worst-affected suburbs, houses and businesses were without power, water and sewerage for some time, and roads were damaged and unsafe. The Government declared a State of National Emergency in New Zealand on 23 February 2011, which remained in place for almost nine weeks. This is the first State of National Emergency in New Zealand's history declared in response to a civil defence emergency, illustrating our unique circumstances.

In the months following the earthquake, the Canterbury Earthquake Recovery Authority (CERA) was created as an arm of Government to lead the region's recovery and rebuild, led by former Orion Chief Executive Officer (CEO) Roger Sutton. Orion's leadership and highly effective earthquake responses were recognised with this appointment.

As a result of the earthquakes, the Christchurch central business district (CBD) was altered irrevocably. By mid 2012, the CERA estimated that more than 650 buildings had been demolished in the CBD. CERA estimates that there will be over 1,100 CBD building demolitions. This widespread destruction not only has a severe economic impact on Canterbury, it has also imposed significant social and cultural costs to our region and its people.

1.1.2 How we had prepared

Over the last 20 years, risk identification and management have been important parts of Orion's planning.

We believed that a resilient network could play an important part in the rapid restoration of electricity supplies after a disaster and the wellbeing of our community. We were right.

Over the years, working with national grid owner Transpower, we engineered a strong electricity supply network for Canterbury. Where risk to the power supply couldn't be easily eliminated, we reduced it through better emergency training, skilled people, safer work practices and improved planning and network design.

In the mid-1990s, we participated in a local engineering lifelines study. This considered how natural disasters might affect Christchurch and Canterbury. That study prompted us to spend $6m on seismic-protection and strengthening work for our key substations over 15 years. Many older brick buildings in Christchurch were hard hit in the earthquakes and ensuing aftershocks, but only four of our 314 (mainly brick) substations sustained serious damage.

Over 15 years we bolted transformers down and tied down other equipment in our substations. We learnt this from the 1987 Edgecumbe earthquake, when large transformers fell over, leaving some areas without power for weeks. We also braced our substation buildings, using good engineering practice based on advice from an experienced structural engineer.

We invested in good technology. We installed innovative wireless communications equipment that continued to operate throughout the earthquakes. This helped us restore power in rural Canterbury sooner than we would otherwise have been able to. Where possible, we also designed route diversity and prudent redundancy into our network.

Our pricing incentives to large electricity consumers, such as hospitals and the Police, had encouraged them to install diesel generators for use during periods of peak power demand. This meant they were well prepared with back-up power when the earthquakes struck.

Prior to the earthquakes, we developed Mutual Aid Partner agreements with other electricity distribution businesses (EDBs) to provide support in the event of large scale natural disasters. We were able to trigger these vital agreements in the aftermath of the February 2011 earthquake.

We regularly contributed to emergency readiness programmes run with Civil Defence and other utility organisations including the Canterbury Lifelines Utilities Group. These exercises enabled us to test our emergency procedures and make improvements from the lessons learnt.

Our pre-earthquake strengthening work and planning paid off for consumers and the Canterbury economy. Damage to our network, while extensive, was far less because we had already invested in network resilience. In other words, our network was resilient and performed well despite the unprecedented force of the earthquakes.

All of our preparatory work and investment was in line with what our consumers have consistently told us over many years, that consumers want us to 'keep the lights on'.

However, such was the force of the earthquakes, that some damage to our network was unavoidable.

1.1.3 Impact on our network

The major earthquakes have damaged our network. They have also caused significant damage to homes, particularly in the eastern suburbs of Christchurch and businesses, particularly in the central business district of Christchurch.

The damage has also compromised our network's performance, resulting in more network outages than consumers experienced before the earthquakes and making our network less resilient to future events such as major snow storms – particularly in the city's eastern suburbs.

There were extensive power cuts following the 4 September 2010 earthquake. Approximately 80% of these outages were caused when the shaking tripped the safety devices on our transformers. These devices successfully reduced damage to our lower voltage network and minimised the possibility of fire. As our substation buildings were seismically reinforced, all of them remained operational, despite some cracking, sinking through liquefaction and other damage. There was also some damage to our overhead lines and underground cables and ancillary equipment such as poles and insulators.

The damage caused by the September 2010 earthquake seemed significant; but the scale of the destruction six months later has put this into perspective.

The 22 February 2011 earthquake resulted in one of the highest ever recorded ground force accelerations. The sheer force of it meant that the damage and the impacts on consumers were about ten times greater than for the first earthquake.

This earthquake hit properties and infrastructure hard throughout the eastern suburbs. It also forced the virtual abandonment of the CBD, a significant portion of which remains off-limits over two years later. The lateral forces caused more faults on our network than we would normally see in an entire decade. Our substation buildings and poles also moved in areas badly affected by liquefaction. For example our Brighton zone substation sank over a metre into the ground, and flooding caused by liquefaction inundated other substations.

We believe that we have managed our network efficiently and prudently over many years. We believe that the relative lack of earthquake-related damage to our key substations, and our effective responses to the earthquakes, has confirmed our previous prudent investment in network resilience and our asset management practices.

Our major emergency repairs are finished, but there is still work ahead to restore resiliency and reliability back to our electricity network, consistent with consumer demands and in their long term interests. Continuity of electricity supply (and confidence in it) is absolutely vital to the future of the city, the region, our community.

Our most important roles are to keep the power on where and when it is needed; quickly respond if supply is disrupted; provide timely and accurate information during major power cuts; and efficiently supply new and upgraded connections. These roles will be particularly important during the region's recovery and rebuild phase over coming years.

1.2 Reasons for our proposal

Our network prices and network quality standards are regulated by the Commerce Commission (the Commission) under Part 4 of the Act.

The overarching purpose of Part 4 is to promote the long term interests of consumers. In promoting the long term interests of consumers, the Part 4 purpose statement recognises that incentives for investment, innovation, efficiency that meet consumer requirements for quality of services are central to the regulation which governs our network prices and quality standards. Thus the purpose statement contemplates and establishes a regulatory regime that balances stakeholder interests.

The purpose statement in section 52A of the Act states:

> The purpose of this Part is to promote the long-term benefit of consumers in markets referred to in section 52 by promoting outcomes that are consistent with outcomes produced in competitive markets such that suppliers of regulated goods or services —
>
> a) have incentives to innovate and to invest, including in replacement, upgraded, and new assets; and
>
> b) have incentives to improve efficiency and provide services at a quality that reflects consumer demands; and
>
> c) share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices; and
>
> d) are limited in their ability to extract excessive profits.

In this CPP application, we propose new CPP price and quality standards to apply for five years commencing on 1 April 2014. We believe that our CPP proposals are consistent with the long term objectives of Part 4.

We have applied for a CPP because our post-earthquake circumstances are no longer able to be accommodated within our current Default Price-Quality Path (DPP) settings. This is because of the significant impacts of the catastrophic earthquakes on our business.

The earthquake impacts and the need to restore network resilience and reliability mean that we have incurred and will continue to incur significant costs. These costs are not reflected in our current network prices because our regulated price cap was determined prior to the earthquakes. These prices also do not reflect our post earthquake reduced revenues, from which we must seek to recover our costs

Our regulatory DPP means that we have been unable to adjust our prices to match our revenue with our costs. This prevention of recovery of our efficient and prudent costs undermines our investment incentives as we seek to continue to invest to support the region’s wider rebuild.

It is important that we continue to invest in and manage the assets which provide electricity distribution services in Christchurch and Canterbury. Electricity is an essential service, and our consumers have told us that they value this service, and that they support our plans to restore our network resilience and reliability.

The long term consequences of under investment are potentially severe for consumers of this essential service. Cost recovery is an important element of retaining our incentives to continue with this vital investment.

In workably competitive markets, prices for goods and services adjust quickly to reflect new realities and new efficient levels – whether such changes are caused by supply or demand effects. In our case, regulation has prevented such efficient price adjustment occurring for over three years. This regulatory delay means that there is a significant element of catch-up cost recovery (claw-back) in our CPP price path proposal calculations.

Our regulated network reliability limits are also fixed at pre-earthquake levels and so they do not reflect the damaged state of our network.

Accordingly, we must apply for modifications to our regulated network prices and our regulated network reliability limits.

Our CPP proposals are consistent with consumer feedback, both before and after the earthquakes (including consumer feedback on our draft CPP proposals in late 2012). This feedback tells us that our consumers want us to restore pre-earthquake levels of network resilience and reliability.

There are significant costs to achieve this. We are seeking to recover our costs.

A key element of Part 4 is to ensure that we (and all EDBs) continue to have incentives to invest for the long term benefit of consumers, to a quality that those consumers seek from us. Recovery of our prudent (but uninsurable) costs and losses is an essential element of retaining our incentives to continue to invest for the long term benefit of consumers.

If we are not able to adjust our network prices to recover our prudent (but uninsurable) costs and losses then our incentives to continue to invest will be greatly diminished – at the very time that our community expects us to continue to invest to support the wider rebuild and relocation efforts in their long term interests.

Our work to restore network resilience and reliability is not yet complete and our consumers support us completing that work, as outlined in our CPP proposal.

We seek simple cost recovery (not a gain or excessive profits) so that our interests continue to be aligned with consumers' long term interests. Cost recovery therefore includes recovery of our fair but not excessive cost of capital over time.

We have adopted a balanced approach between the interests of consumers and the interests of the company. Within the constraints of the IMs, we have deferred our proposed cost recovery to mitigate short to medium term pricing impacts on consumers.

Our CPP application and proposal documents fully set these matters out – particularly:

- our proposal to restore our network resilience and reliability back to near pre-earthquake levels by FY19
- our proposal to increase our network prices to recover our prudent (but uninsurable) earthquake related costs and losses (including our cost of capital)

- our proposal to apply an alternative depreciation method within the CPP period to reduce the amount of depreciation expense to be recovered from consumers between now and FY19 by around $30m
- our proposal to spread our recovery of claw-back over 10 years to mitigate the price impacts for consumers, effectively delaying recovery of $43m of claw-back related costs until after the CPP period
- how we ensure our expenditure is prudent and efficient.

The preparation of this proposal has been challenging. Ours is the first CPP application to be made under Part 4. Accordingly there are no precedents; we are the first to apply the Commission's CPP IMs; and the associated Part 4 regulatory mechanisms (the DPP and Information Disclosure (ID) regulations) are not yet fully implemented.

Further, because our CPP proposal is in response to a catastrophic event, many of the prescribed IM requirements are not directly relevant to our current circumstances. We also face unprecedented uncertainty in Canterbury as to the likely future demand for our services and the costs of providing those services. Decisions are being made by others on a regular basis that impact on our operations and plans.

Notwithstanding these challenges, we have prepared a comprehensive CPP proposal, which we believe fully meets the Commission's IM requirements.

Where appropriate, we have sought and carefully considered independent expert advice and carefully considered that advice as part of preparing our CPP proposals. We have included key expert advice (including peer reviewed expert advice on cost recovery principles) in this CPP proposal.

In late 2012, we sought feedback from our consumers on our draft proposed CPP price path and quality standards. In our accompanying CPP application document we summarise the feedback we received. We received 38 submissions from consumers and organisations. Most supported our draft CPP proposals and this CPP proposal is consistent with our draft proposals.

Consumers largely support our cost recovery proposals.

We believe that our CPP proposal reflects prudent and efficient expenditures and realistically achievable quality standards which together meet the long term interests and demands of our consumers. Our price path proposals reflect our desire to mitigate the pricing impacts on consumers by spreading our cost recovery over the long term.

Our decision to apply for a CPP has not been taken lightly. However we believe it is appropriate for us to do so after carefully considering the long term interests of our key stakeholders – namely consumers, the broader Canterbury community and our shareholders.

1.3 Proposed quality standard

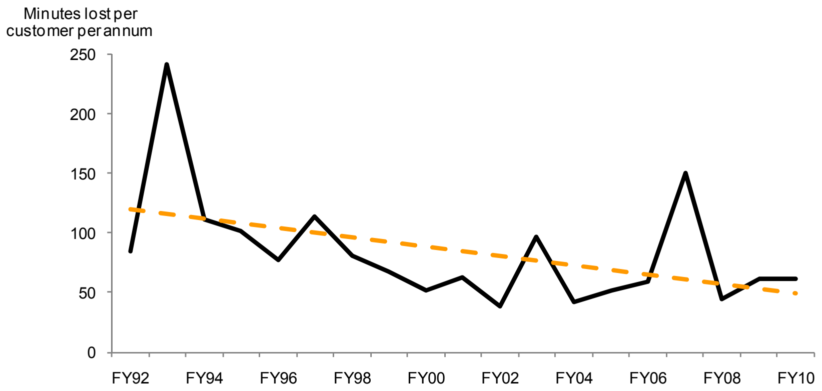
Prior to the earthquakes our electricity distribution network was one of the most reliable in New Zealand. In the five years to 31 March 2010, we were:

- the fifth best performing EDB in terms of average interruption duration (SAIDI)

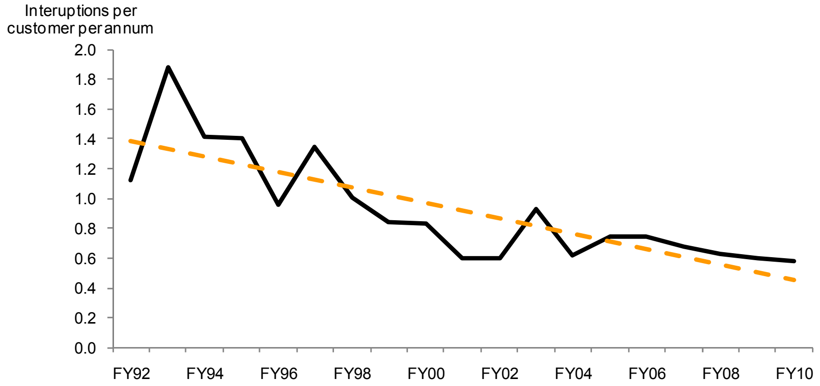
- the second best in terms on average interruption frequency (SAIFI).

This reflects continual improvements in our reliability since the early 1990s, as illustrated below. The charts also illustrate the impacts of extreme weather events with significant disruption in FY93, FY97, FY03 and FY07 due to severe snow storms in Canterbury.

Orion SAIDI performance from FY92 to FY10 with trend

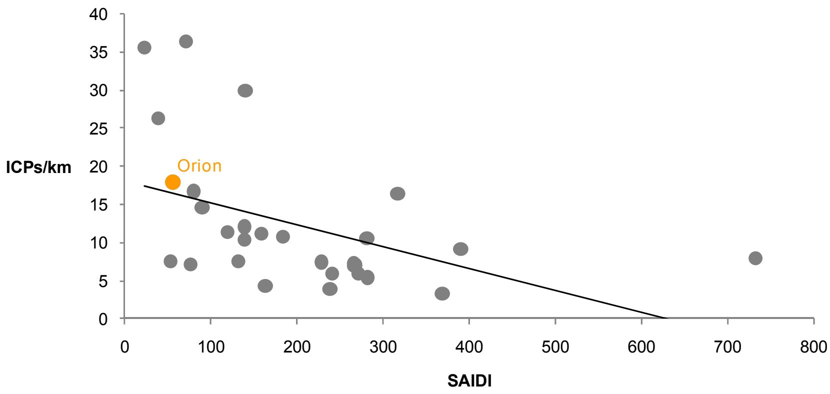


Orion SAIFI performance from FY92 to FY10 with trend

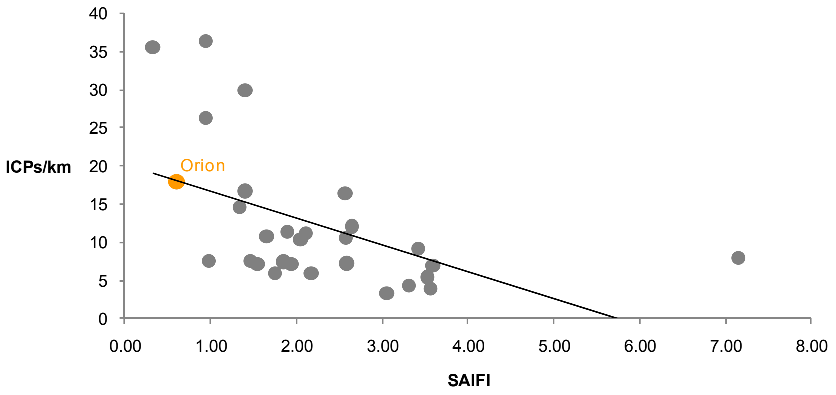


Our pre-earthquake performance is consistent with the expectations of our consumers, and, as illustrated below using FY08 - FY10 data, is as expected for a relatively high density network.

New Zealand EDBs average SAIDI FY08 - FY10 (class B & C)



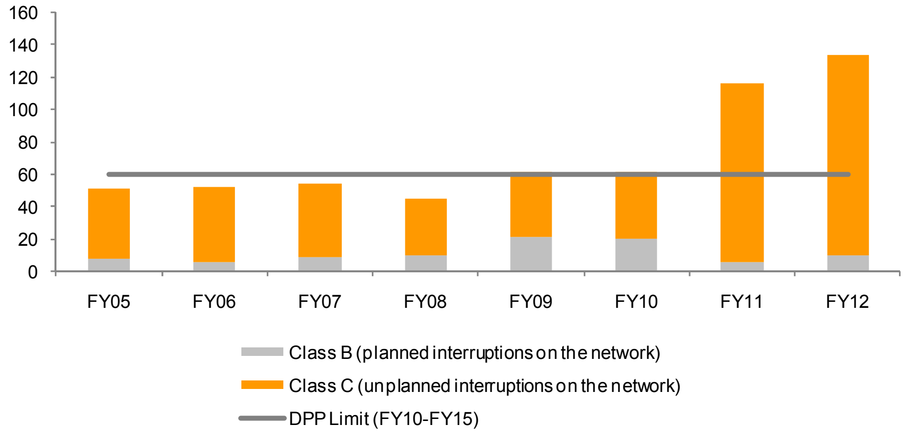
New Zealand EDBs average SAIFI FY08 - FY10 (class B & C)



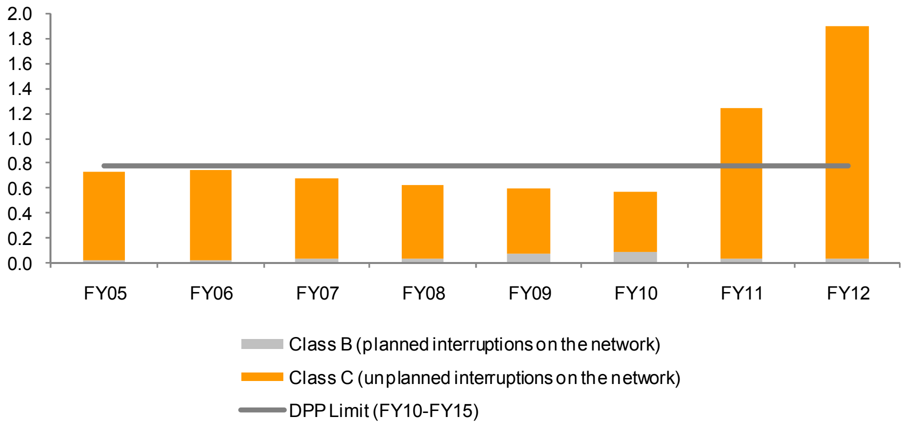
Our current DPP quality standards (which are expressed as SAIDI and SAIFI limits) are 59.7 SAIDI (minutes) and 0.76 SAIFI (interruptions). These limits are based on a regulatory methodology which makes adjustments for extreme and normal variation in the datasets used to set the limits and assess performance against them.

As a result of the damage to our network, and the houses and businesses of our consumers, we have been unable to meet these limits since the earthquakes. The FY11 and FY12 breaches of our DPP quality standards are illustrated below, along with our historical performance since FY05. FY05-FY09 represents the reference period used to establish the DPP limits.

SAIDI (normalised)



SAIFI (normalised)



Accordingly we are seeking a quality standard variation for the CPP regulatory period. The key feature of our proposed quality standard variation is that our network reliability limits increase initially to accommodate our current circumstances and the state of our network, and then gradually reduce across the CPP regulatory period, reflecting improving network resilience and reliability between now and FY19. This trend reflects the re-establishment of the resilience of our network which was severely damaged during the 2010 and 2011 earthquakes and our planned expenditures to achieve that restored resilience up to FY19.

Our proposed quality standard variation is summarised in the following table. It has been derived from detailed analysis of past SAIDI and SAIFI performance, with particular consideration of the performance of our network since the earthquakes.

CPP regulatory period

	FY15	FY16	FY17	FY18	FY19	Current DPP standards
µSAIDI	94.7	86.5	83.1	75.2	67.0	53.0
σSAIDI	9.0	8.2	7.9	7.2	6.4	6.7
SAIDI limit	103.8	94.7	91.0	82.4	73.4	59.7
µSAIFI	1.25	1.11	1.07	0.94	0.80	0.68
σSAIFI	0.11	0.09	0.09	0.08	0.07	0.10
SAIFI limit	1.36	1.21	1.16	1.02	0.87	0.78

In the above table:

- µSAIDI and µSAIFI means the average annual SAIDI/SAIFI in the normalised dataset
- σSAIDI and σSAIFI means the standard deviation of daily SAIDI/SAIFI values in the normalised datasets multiplied by the square-root of 365.

These variables are summed to determine the SAIDI and SAIFI limits.

Our proposed CPP network quality standards are consistent with our expenditure plan, are realistically achievable and importantly reflect expected significant improvements in our reliability performance over the CPP period, consistent with the expectations of our consumers.

We aim to restore our network to pre-earthquake levels of resilience and reliability. Our proposed quality standards achieve near pre-earthquake levels by FY19. As illustrated above, our pre-earthquake performance is consistent with that expected for a largely urban network.

Based on consumer feedback we have received over many years prior to the earthquakes we believe that consumers were satisfied with the levels of network resilience and reliability we had prior to the earthquakes.

Feedback on our draft CPP proposals in late 2012 (post-earthquakes) indicates that the majority of consumers who responded to our draft CPP proposals want us to return to pre-earthquake levels of network resilience and reliability. This target and feedback is consistent with the regulatory rules which have applied to us for the best part of the last decade, which have established a 'no material deterioration' reliability standard for all EDBs subject to the Part 4A thresholds regime, and more recently the Part 4 price-quality regime.

We anticipate that there will be year on year variations in network reliability. Our quality standards have been developed using a similar approach to the current DPP limits, to attempt to accommodate such variation. We note that we have a higher than usual degree of uncertainty about our expected reliability performance given the damage to our network, the impact of the city recovery plans which are only just emerging and the impacts of others working around our network.

We have carefully considered how to achieve the quality of supply sought by our consumers. We propose a glide path which incorporates year on year improvements in network reliability as the best means to meet our consumers' needs. This glide path is consistent with the level of investment provided for in our price path, which includes a number of important projects within the CPP regulatory period aimed at restoring our network resilience and reliability. The glide path also reflects our view of the likely planned and unplanned interruptions to our network caused by external parties and external events.

Notwithstanding the significant improvements we have proposed, we do not expect to achieve the same level of reliability by the end of the CPP period, as we had prior to the earthquakes. We expect further improvements in our reliability will be made after the end of the CPP.

1.4 Proposed price path

1.4.1 Financial impact of earthquakes

We have not increased our network prices in response to the earthquakes due to regulatory constraints. We implemented a CPI related price increase on 1 April 2011 that was prepared pre-earthquake. We had no increase on 1 April 2012 and we are implementing a further CPI related price increase on 1 April 2013. These price increases are in line with the current DPP regulation which applies to us. Accordingly, our prices have not kept pace with general inflation due to the nil increase on 1 April 2012.

Our costs have increased significantly and our revenues have decreased due to reduced demand arising from disruption to our consumers. Further, we need to continue to spend above historical levels for the foreseeable future to restore our network's resiliency and reliability, and to support the city rebuild and growth.

For example, the following table summarises the material cash impacts (relative to pre-earthquake forecasts) for two financial years, FY11 and FY12. We note that as time goes by it becomes more difficult to distinguish between earthquake and non-earthquake spending and revenue impacts.

Financial impact of earthquakes

($m pre-tax)	FY11	FY12
Increased operating expenses	12.6	14.0
Increased major capex	-	10.6
Reduced electricity delivery revenue	3.1	20.6
Insurance settlement revenue	-	22.3

A comparison between our CPP forecasts and our 2010 AMP (published in March 2010, prior to the first major earthquake in September 2010) demonstrates that, for FY13 to FY19, we are now forecasting:

- $156m more in network capex than in 2010
- $22m less in network maintenance than in 2010.

These values are expressed in FY13 real terms and exclude the impact of increases in non network expenditure, such as our new head office site and building, and input cost inflation which has increased in Canterbury post-earthquakes.

1.4.2 Uninsurable costs

We believe we prepared as prudently as possible for the possibility of catastrophic events. We estimate our pre-earthquake seismic protection and planning has saved us $60m to $65m in direct asset replacement costs. It also avoided considerable further disruption to our community's economic and social well being.

Orion, like other infrastructure entities, cannot feasibly insure its entire network against catastrophic damage. Orion has not insured overhead lines and underground cables because it has been, and still is, uneconomic to do so. Even before the 22 February 2011 earthquake, an annual insurance premium for lines and cables alone was estimated to be around $100m (based on an asset replacement value for cables and lines of around $1 billion). This is clearly uneconomic and it is even more so after the earthquakes.

The premiums charged for other network assets, such as substations and buildings, are more affordable. Consequently, we have and continue to fully insure all of our key substations and our head office at full replacement cost. We continue to insure our remaining substations and other assets where insurance premiums are at a prudent level.

An independent expert report prepared by international broker Marsh confirms that EDBs around the world face the same insurance circumstances: that is underground cables and overhead lines risks are normally uninsured because insurance underwriters are not able to provide material damage and business interruption coverage for them. Marsh also confirms that, in its opinion, our approach to insurance has been entirely appropriate, reasonable and consistent with that of other network companies in Australasia.

1.4.3 Recovery of prudent and efficient costs

In this CPP, we propose to recover our prudent and efficient costs to provide electricity supply services to Canterbury. We believe that electricity consumers should pay the prudent and efficient costs for our electricity supply services provided at a quality consistent with their demands. We have been unable to recover our fair costs since the earthquakes because of the regulatory constraints imposed on our prices. We believe that it is in consumers' long terms interests for us to recover our costs.

Electricity consumers are the beneficiaries of the services we provide, and it is appropriate that consumers pay for the actual prudent and efficient costs of those services in both good times and bad. Cost recovery retains our incentives to continue to invest in our network, for the long term benefit of consumers. Non recovery diminishes those incentives. Cost recovery also enhances the efficient allocation of resources by ensuring appropriate consumption and investment decisions are made by consumers.

We have carefully considered an option to reduce the size of our proposed line price increases and not fully recover our costs. We have rejected this option because it would not be in the long term interests of consumers (because it would reduce our incentives to continue to invest) and so would be contrary to consumers' long term interests and the Part 4 purpose statement.

We have also taken and carefully considered expert independent economic advice on this issue (refer appendices 1 and 2 for copies of these reports prepared by Jeff Balchin of PwC and James Mellsop and Will Taylor of NERA).

The expert advice strongly advocates full cost recovery.

Mr Balchin observes that price regulation seeks to protect consumers from the misuse of monopoly power while ensuring the provision of services which meet their demands. These objectives are '*almost universally*' achieved by setting regulated prices to recover prudent and efficient costs, including a commercial return on investment.

This tension is explicitly addressed in the Part 4 purpose statement, particularly in its requirement for the regulatory framework to:

- provide incentives for suppliers to invest and innovate
- limit a supplier's ability to extract excessive profits.

Mr Balchin notes that catastrophic events raise the costs of providing the service and lead to a loss of revenue. He concludes that following a catastrophic event, prudent and efficient costs (including the impact of lost revenue) should be recovered from consumers consistent with the treatment of costs in general.

Mr Balchin also considers how such costs (including lower revenues) should be recovered. He concludes that compensation after the event (ex post) is more practical than the alternative (a self insurance revenue allowance included in regulated prices before any such events) because the latter (ex ante) alternative is very difficult to achieve. He also concludes that an ex post approach is consistent with the regulatory regime which currently applies to us.

Mr Balchin also tests whether our proposals are consistent with outcomes which are expected in competitive markets. This test is fundamental to the overarching Purpose Statement of Part 4 of the Act, which sets out the regulatory framework which applies to us. He observes that all investors, irrespective of the nature of the market, expect to make a commercial return on their prudent investments after recovering efficient costs.

The key difference for regulated businesses is when they are able to recover their costs. Mr Balchin observes that the limited nature of the insurance market for EDBs, and the fact that prices are regulated means that EDBs, like Orion, are restricted from including reasonable ex-ante allowances for uninsured costs in their prices, unlike firms operating in competitive markets.

Finally Mr Balchin observes that it is reasonable for Orion to expect to achieve a commercial rate of return. He concludes that this outcome holds irrespective of ownership, and notes that setting cost reflective prices for consumers encourages broad economic efficiency by encouraging efficient consumption decisions. [1]

This expectation of full recovery of costs over time is essential to the long term sustainability of all businesses, including EDBs. As Mr Balchin states:

> *Absent an expectation of cost recovery it is not possible for a business to remain in operation over the medium to longer term.*
>
> *The expectation of future cost recovery is particularly important in the context of electricity networks. This reflects the essential service nature of electricity and that its provision involves significant sunk assets with costs recovered over an extended period of time; sometimes up to 40 years or more. If investors perceived there were risks that they would not be able to recover at least their efficient costs of service provision over time, there would be a diminished incentive to make future investments to the detriment of reliable supply for consumers.* [2]

Our proposal, which seeks to recover our fair costs, which we have been prevented from recovering since the earthquakes, is therefore consistent with the long term interests of our consumers. It is necessary for us to recover these costs in order for us (and other EDBs) to have a reasonable expectation of earning a fair return over time, and therefore continue to make the investments required to meet consumer demands for electricity distribution services.

In their independent expert peer review, Messers Mellsop and Taylor of NERA, agree with Mr Balchin's findings. They also conclude that uninsurable losses resulting from the earthquakes should be recovered from consumers on an ex post basis.[3]

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[1] Refer Jeff Balchin, PricewaterhouseCoopers, Long term-incidence of cost recovery following a catastrophic event, 17 December 2012, pages 2-4 (included as appendix 1)

[2] Ibid page 8

[3] Refer, James Mellsop and Will Taylor, NERA, Peer review of PwC report on cost recovery following a catastrophic event, 30 January 2013 (included as appendix 2)

We note that under recovery of efficient and prudent costs would also be contrary to our statutory obligation under section 36 of the Energy Companies Act to operate as a successful business.

The value of investment in essential infrastructure is well demonstrated by the earthquakes. Our long term prudent investment in network diversity, seismic strengthening and risk mitigation measures significantly reduced the impacts of supply interruptions for consumers. Had we not made these investments, consumers, and the wider Canterbury community, would be considerably worse off.

Our proposed cost recovery includes ex-post compensation for reduced revenues as a result of the earthquakes which has contributed to our under recovery of our costs since the earthquakes.

Consistent with the independent expert advice we have received from PwC and NERA, we believe that where reduced consumption arising from a catastrophic event has contributed to under recovery of costs, EDBs should be compensated for this on an ex-post basis under a CPP, to ensure they are able to recover prudent and efficient costs. No provision for uninsurable catastrophic risk was allowed for in our pre earthquake DPP price path.

1.4.4 Claw-back

The Part 4 provisions for a CPP made in response to a catastrophic event allow us to look backwards to the date of those events by including the value of 'claw-back' in our price path proposal. In this instance claw-back reflects the shortfall in revenues required to recover our costs, which occurred following the catastrophic event(s), up to the date that the CPP comes into effect.

As the earthquake activity commenced in September 2010, we have considered the impact of the earthquake events which have occurred from that date up to the commencement of the CPP period, up to 1 April 2014. This is our proposed claw-back period.

Our proposed claw-back allowance seeks to recover our earthquake related costs which were not anticipated when our DPP price path was set. This ex-post cost recovery is:

- consistent with the manner in which the DPP price path was set (because our DPP price path includes no allowance for unanticipated costs of this nature)
- in the long term interests of consumers.

It ensures that we retain the economic incentives to continue to provide the services that consumers require of us because we are compensated for our prudent and efficient costs in providing those services, including a risk adjusted commercial return on our investment.

Our proposed claw-back recovery extends over ten years, beyond the end of the CPP period. This reflects our desire to mitigate pricing impacts on consumers where possible within the regulatory rules and methods we must apply.

1.4.5 A CPP in response to a catastrophic event

The earthquakes changed our operating environment, and our costs in providing the services demanded by our consumers. Since 4 September 2010 we have been unable to recover our costs, because of the constraints of our DPP price path. Many of our earthquake related costs are not insurable.

Consumer demand and our revenue significantly reduced after the earthquakes. Our efficient costs of distributing electricity to each consumer in Canterbury consequently changed – despite our prudent insurance programme and our prudent pre-earthquake seismic strengthening and network resiliency programmes.

The DPP sets price and quality standards for us for a period of five years. Within those standards there is cost and volume risk as well as network reliability risk for us. All of these factors were detrimentally affected by the earthquakes. The DPP was not intended to be able to fully accommodate these potential impacts where they arise from a future catastrophic event. The Act provides for a CPP alternative, and indeed the DPP Determination and IMs acknowledge the situation where an EDB subject to the DPP may be required to apply for the CPP in response to a catastrophic event.

In this instance, provision is included for claw-back which may be applied on an ex-post basis to address the consequences of the catastrophe that were not anticipated (and hence reflected) in the DPP price path or quality standards.

This is the situation we are faced with, and hence we have prepared this proposal on the basis that our CPP will address the cost, volume and reliability impacts on our business since September 2010 that the DPP has not been able to accommodate.

A fundamental principle, as articulated by PwC and NERA, is that workably competitive markets permit providers to recover efficient costs. It is the characteristics of the relevant market that determine whether costs caused by events like the Canterbury earthquakes are recovered before or after the relevant event, or through a combination of both. Importantly in this context, there is no conceptual difference between unanticipated impacts on demand (and hence revenue), and unanticipated costs.

Claw-back is caused by the regulatory delay in resetting prices to new efficient levels, relative to what happens in workably competitive markets. In workably competitive markets prices adjust quickly, in our case our prices cannot adjust quickly due to regulation.

The price control regime has prevented us from adjusting our prices to efficient levels post earthquake in a timely manner. In a workably competitive market and in the absence of price control we would have been able to quickly adjust its prices to new efficient levels that reflected the new demand and supply cost realities. Instead, we must continue to recover revenue well below pre-earthquake levels for at least three years up to 1 April 2014 due to a regulatory constraint. Our pre-earthquake prices are no longer cost reflective and therefore cannot be considered to be efficient.

It is reasonable and in consumers' long term interests for us to recover our efficient costs and to recover these costs from consumers. We believe that the legislative intent is that we should be able to do this on an ex-post basis (where a catastrophic event has occurred) through a CPP so that our incentives to continue to invest for the benefit of consumers are preserved.

Our proposed claw-back recovery in our CPP price path is consistent with this intent.

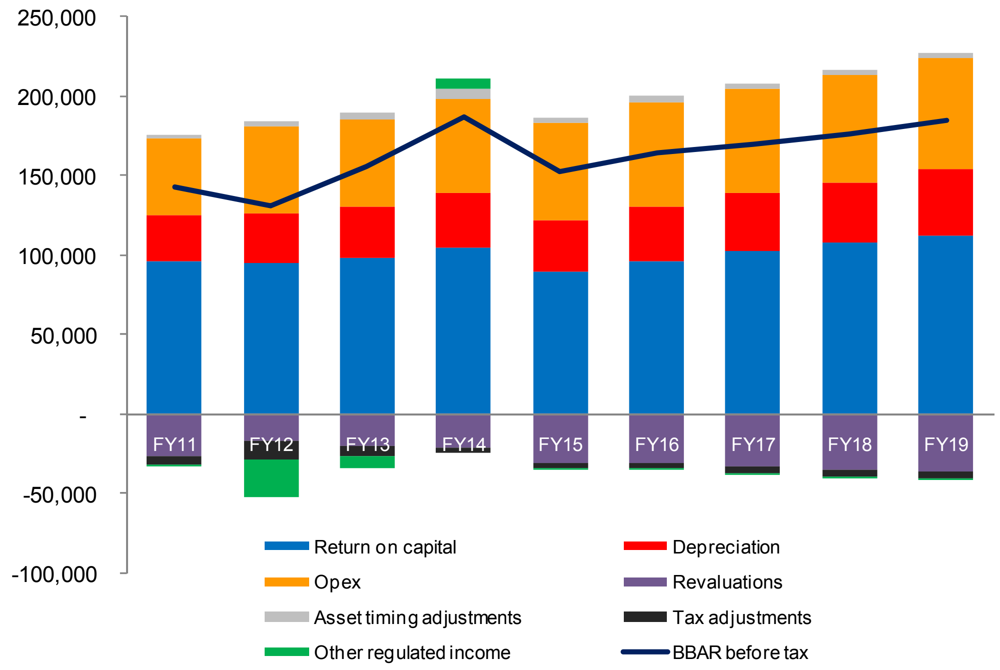
We have made no allowance in our CPP proposal for unanticipated costs associated with possible future catastrophic events. We have no self insurance allowance in our opex forecast. If such events occur within the CPP regulatory period, we are able to reopen the CPP to address the impacts at that time. Thus we propose an ex-post approach to the recovery of the consequences of potential future catastrophes, as anticipated in the IMs. This is the same as the ex-post claw-back allowances that this CPP proposal addresses for the consequences of the 2010 and 2011 Canterbury earthquakes.

1.4.6 Building blocks allowable revenue

We have determined our required revenue allowances using the methods set out in the CPP IM which have been determined by the Commission as being consistent with the Part 4 purpose statement. These revenue allowances are consistent with fair prices for consumers and providing appropriate incentives to suppliers to meet consumer requirements over the long term, in their long term best interests.

Our building blocks allowable revenue (BBAR) for the CPP regulatory period, and prior years incorporating the claw-back period, is illustrated below.

Building blocks allowable revenue before tax, by component ($000 nominal)



BBAR before tax ($000)	Current Period		Assessment Period	
	FY11	FY12	FY13	FY14
Return on capital	95,824	95,144	97,776	104,195
Depreciation	29,337	30,838	31,917	34,211
Opex	48,146	54,914	55,238	59,397
Revaluations	(26,617)	(17,271)	(20,476)	(21,110)
Asset timing adjustments	1,960	2,737	4,538	6,202
Tax adjustments	(5,236)	(11,725)	(6,367)	(3,184)
Other regulated income	(488)	(23,710)	(7,438)	7,021
BBAR before tax	**142,926**	**130,926**	**155,189**	**186,732**

	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Return on capital	88,878	95,654	102,781	107,294	112,367
Depreciation	32,285	34,388	36,238	38,274	41,230
Opex	61,738	65,809	65,449	66,997	70,460
Revaluations	(30,546)	(30,834)	(33,357)	(35,023)	(36,752)
Asset timing adjustments	3,468	4,115	3,168	3,540	2,748
Tax adjustments	(3,174)	(3,686)	(3,964)	(4,102)	(4,129)
Other regulated income	(830)	(848)	(866)	(885)	(904)
BBAR before tax	**151,819**	**164,599**	**169,450**	**176,095**	**185,020**

The return on capital allowance has been calculated using the cost of capital determined in September 2012 by the Commission for a five year CPP price path commencing 1 April 2014. We have applied the DPP cost of capital for the claw-back period, as this is the cost of capital allowance which applies to EDBs subject to the DPP within this period (including Orion if we had not required a CPP).

In deriving the building blocks for the CPP regulatory period, we have chosen an option available in the CPP IM to modify our depreciation allowances using a non standard depreciation approach. This is the only mechanism available to us (within the regulatory methods we must use) to reduce the building blocks within the CPP regulatory period, for a given expenditure plan.

Our proposed approach, which reduces the depreciation to be recovered within the CPP period relative to the standard approach, allows us to better align the recovery profile for our return of capital allowance with the economic recovery expected in Canterbury over the same period. This is also consistent with our desire to minimise price shocks within the CPP regulatory period as much as possible, consistent with consumer feedback we received on our draft CPP proposals in late 2012.

We propose to recover depreciation on new assets constructed following the earthquakes at a slower rate than the standard straight line method applied for DPPs and the default method for CPPs. We believe this is consistent with the long term interests of consumers as the recovery profile better matches the demand for our services which is expected to recover relatively slowly over the CPP regulatory period.

Our proposed depreciation approach reduces the amount of revenue we propose to recover during the CPP regulatory period, and it increases the amount we propose to recover in later years, once demand has recovered. Our proposed approach is consistent with the standard approach, in present value terms, over the life of the assets concerned.

Our proposed claw-back allowance uses the same methods as prescribed in the CPP IMs for the forward looking component of the price path. In determining the value of claw-back we have deducted from BBAR, the actual revenue we have and expect to receive over the claw-back period, including our insurance proceeds.

1.4.7 Proposed price path

Our proposed price path comprises maximum allowable revenue (MAR) before tax of $156m for FY15, and an X factor of -1.19% for FY16 - FY19 to apply in the CPI-X component of our price path. The present value of the MAR series after tax is equivalent to the present value of the series of BBAR after tax. This is illustrated below.

Derivation of maximum allowable revenue series ($000 nominal)	**CPP Period**				
	FY15	**FY16**	**FY17**	**FY18**	**FY19**
Inflation rate		2.17%	2.17%	2.17%	2.17%
X factor		-1.19%	-1.19%	-1.19%	-1.19%
Weighted average growth in quantities		0.79%	0.80%	0.85%	0.76%
MAR before tax	155,598	162,136	168,974	176,185	183,540
Regulatory tax allowance	14,234	15,742	16,437	17,183	17,852
MAR after tax	141,364	146,394	152,536	159,002	165,688
TF_{REV}	1.028	1.028	1.028	1.028	1.028
MAR after tax year end	145,252	150,420	156,731	163,375	170,245
	PV at 1 April 2014				
PV of series of MAR after tax	**642,505**				

Note: The annual rate of change in the price path is specified as CPI-X, thus an X factor of -1.19% means real price increases of 1.19%

Present value of series of BBAR after tax ($000 nominal)	**CPP Period**				
	FY15	**FY16**	**FY17**	**FY18**	**FY19**
BBAR before tax	151,819	164,599	169,450	176,095	185,020
Regulatory tax allowance	14,234	15,742	16,437	17,183	17,852
BBAR after tax	137,585	148,857	153,012	158,912	167,168
TF_{REV}	1.028	1.028	1.028	1.028	1.028
BBAR after tax (year-end)	141,369	152,951	157,220	163,282	171,765
	PV at 1 April 2014				
PV of series of BBAR after tax	**642,505**				

We also propose that our CPP price path includes the recovery of claw-back. The following table summarises the value of claw-back which we have determined for the period 4 September 2010 – 31 March 2014. The present value of claw-back at the commencement of the CPP regulatory period is $86.3m.

The value of claw-back ($000 nominal)	Current Period			Assessment Period	
	FY11a	FY11b	FY12	FY13	FY14
BBAR before tax (year end)	57,569	90,313	135,466	160,570	193,207
Actual and projected revenues (year end)	64,195	76,681	129,322	141,091	143,937
Difference	(6,626)	13,632	6,144	19,479	49,270
PV of difference for FY11	8,808				
PV of difference			7,157	21,023	49,270
Total PV of difference (at 1 April 2014)	**86,259**				

Our proposed claw-back recovery increases MAR before tax in FY15 to $164.8m, as illustrated below. The proposed claw-back recovery in FY16 - FY19 is consistent with the slope of our MAR before claw-back over the CPP period. That is, it is consistent with an annual CPI-X rate of change where X is equivalent to -1.19% (and hence provides for annual average price increases of CPI + 1.19%).

MAR including recovery of clawback ($000 nominal)	CPP Period				
	FY15	FY16	FY17	FY18	FY19
MAR before tax	155,598	162,136	168,974	176,185	183,540
Clawback recovery over CPP period	9,175	9,560	9,964	10,389	10,822
MAR before tax plus claw-back recovery	164,773	171,696	178,937	186,574	194,362

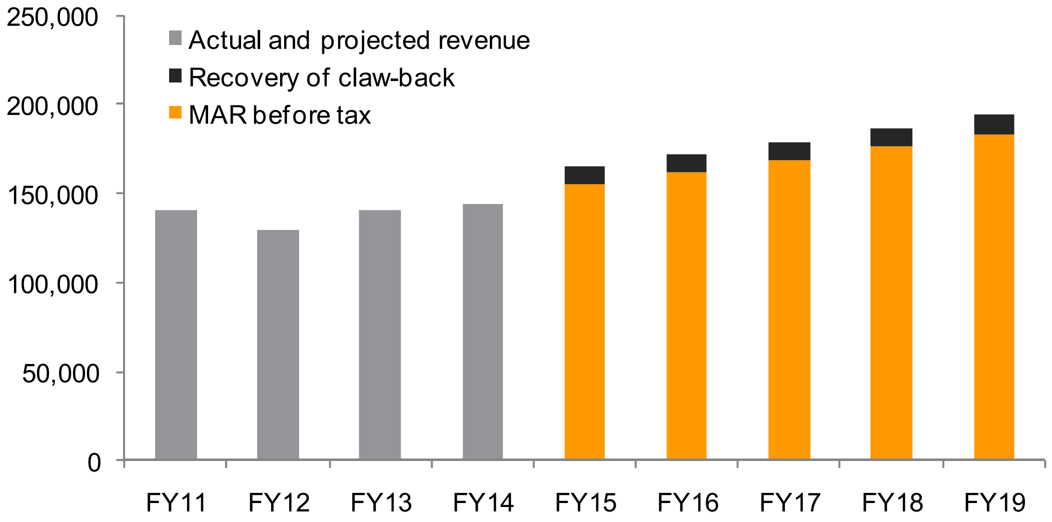
Our proposed price path will not fully recover our claw-back costs within the CPP regulatory period. Our CPP period will be 5 years. We propose to recover our claw-back over 10 years in order to mitigate the price impact on consumers during the CPP period. We propose to recover $43.13m (in present value terms) of the $86.3m of claw-back (half) over the CPP regulatory period.

We propose to recover the remaining $43.13m (in present value terms) in the 5 years immediately following the CPP period (to FY24). The table below shows the value of claw-back, and the proportions recovered during the CPP regulatory period and subsequently.

Claw-back recovery ($000 nominal)		
	PV at 1 April 2014	PV at 1 April 2019
Value of clawback	86,259	
Value of clawback to be recovered in CPP period	43,130	
Value of clawback to be recovered after CPP period	43,130	57,418

The chart below illustrates actual and projected revenues in the years prior to the start of the CPP regulatory period and the MAR (including the claw-back component) during the CPP period.

MAR before tax plus claw-back recovery ($000 nominal)



Our proposed price path (including claw-back) represents a nominal increase to allowable revenue of 18.5% in FY15, and approximately 4.2% each year from FY16 to FY19. After removing the effects of forecast inflation and growth in quantities, this represents real price increases of 15.0% in FY15 and 1.19% each year from FY16 to FY19.

1.5 Expenditure plan

The key objective of our capex and opex programme is to restore network resilience and meet the long term needs of our consumers for a safe, reliable and cost effective electricity distribution service.

Our capex and opex forecasts are for the following core activities, which are consistent with how we manage our business and plan our future needs.

Capex	**Network**	**Major Projects**	
		Reinforcement	
		Replacement	
		Customer Connection / Network Extension	
		Underground Conversions	
		Asset Acquisitions	
	Non Network	**Non System Assets**	
Opex	**Network**	**Maintenance**	**Emergency**
			Scheduled
			Non-Scheduled
	Non Network	**Network Management and Operations**	
		General Management, Administration and Overheads	

In our proposed capex programme we will:

- build new assets to restore resiliency to our network and to meet new demand from consumers (including for the rebuild and new subdivisions)
- purchase local spur assets from Transpower and integrate them into our subtransmission network
- replace existing assets to ensure we continue to meet our network performance targets
- construct a new head office as our office buildings have been demolished following extensive earthquake damage.

In our opex programme we will:

- maintain our network and operate it in accordance with good industry practice
- respond to unplanned events in a timely and effective way
- accommodate the Christchurch rebuild
- ensure the performance of our assets is maintained, consistent with consumers needs.

We aim to ensure our expenditure is prudent and in the long term interests of our consumers. However it has been and continues to be necessary to increase our opex and capex, over pre earthquake levels, for the foreseeable future. This increase is necessary to restore the resilience in our network and improve our service levels to those which are more consistent with the level our consumers expect from us. We are very mindful of the impact of this on our costs to deliver electricity and we continue to seek to find ways to improve our planning and project execution.

We believe that our outsourced field work model facilitates competition in our local contracting market. It enables us to acquire the most efficient prices for our works programme commensurate with the quality of service, skill levels and expertise we require for our network.

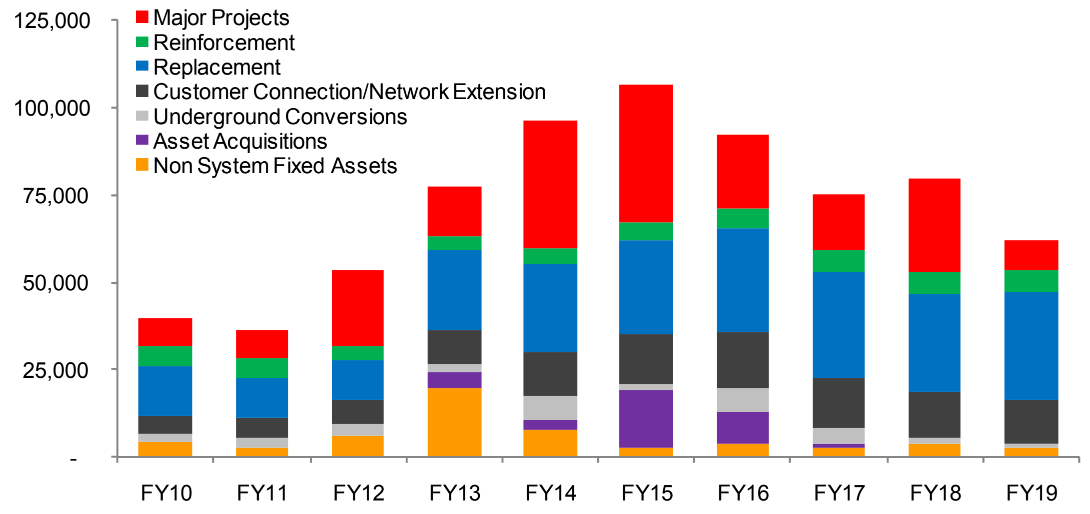
We have benchmarked our historical capex and opex costs against other EDBs and believe that these measures demonstrate that our project delivery practices are consistent with the efficiency objectives of the Part 4 purpose statement.

We note that there is increasing pressure in Canterbury for infrastructure resources and we are starting to see upward pressures on contract prices and labour costs. We are confident that our competitive tendering processes will continue to ensure that we are able to deliver our planned projects as efficiently as possible but we have not been able to maintain our unit costs at pre-earthquake levels due to local demand pressures.

1.5.1 Planned capex

Our historical and forecast capex programme, by activity, is illustrated below. Our capex data is presented for the period FY10 to FY19. Our opex data (refer below) is presented for the period FY08 to FY19. Due to damage to our records and financial systems from the 2011 earthquakes we have not been able to re-categorise our FY08 or FY09 capex data into this CPP presentation format.

Nominal capex by expenditure category ($000)



Nominal capex by expenditure category ($000)	Current Period			Assessment Period		CPP Period				
Expenditure Categories	**FY10**	**FY11**	**FY12**	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Major Projects	8,119	7,855	21,236	14,346	36,329	39,442	21,068	15,623	26,961	8,354
Reinforcement	5,304	5,318	4,480	4,150	4,939	5,348	5,725	6,135	6,310	6,544
Replacement	14,361	11,465	11,181	22,903	24,907	26,433	29,739	30,225	28,058	30,600
Customer Connection/Network Extension	5,113	6,058	6,898	9,650	12,829	14,523	15,616	14,612	13,100	12,703
Underground Conversions	2,588	2,475	3,627	2,300	6,570	1,768	6,862	4,460	1,758	1,096
Asset Acquisitions	-	-	-	4,188	2,700	16,784	9,419	1,198	-	-
Non System Fixed Assets	4,134	2,912	5,880	20,030	7,977	2,409	3,771	2,601	3,633	2,621
Total	**39,618**	**36,083**	**53,301**	**77,567**	**96,252**	**106,708**	**92,200**	**74,854**	**79,820**	**61,920**

Our capex projects and programmes are mainly associated with network security, resilience, new consumer demand and maintaining our service capability. Before spending capital on our network, we consider a number of options including those available in demand side management and distributed generation.

The earthquakes caused significant damage to our network. We are proud of our pre-earthquake network architecture and engineering strategies to minimise the impacts of such events and we are pleased with our operational response during the response and recovery phases. There is much to be learnt from an event of this scale and this, coupled with permanent network damage, is resulting in inevitable changes to our pre-earthquake network development plans.

In particular the earthquakes have prompted us to review:

- the architecture of our network
- our network security of supply standard
- some of our design standards
- our load forecasts
- our embedded mobile and fixed standby generation strategy.

While these reviews are ongoing, our capex forecast incorporates our most up to date knowledge and thinking on each of these.

The key driver for our urban network capex programme over the CPP period is our drive to restore network resiliency, and accommodate the post earthquake relocations and rebuild.

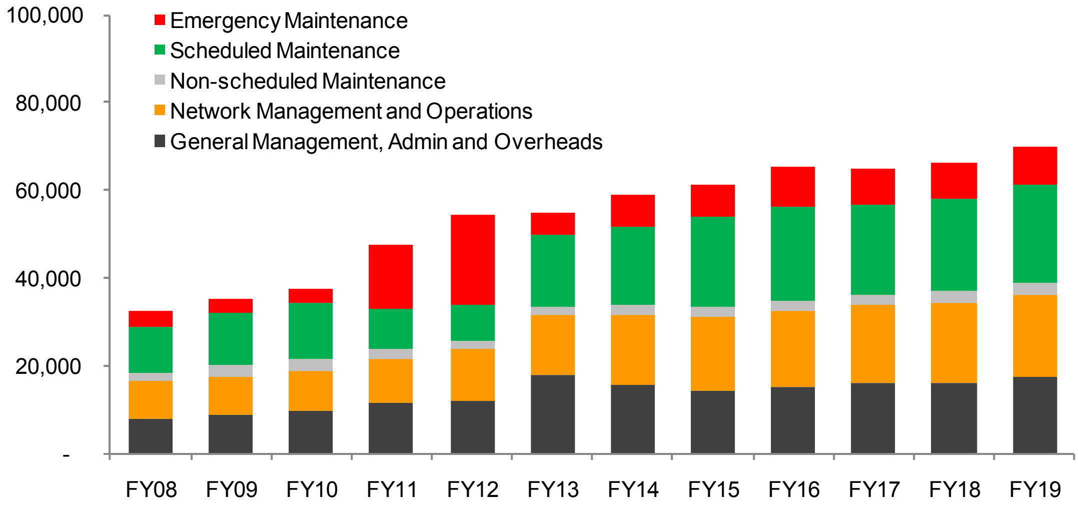
The acquisition of Transpower spur assets located within our network supply area is a core part of our urban subtransmission development plan.

The key driver for our rural capex programme is meeting growth (particularly relating to the dairy industry) and maintaining appropriate quality of supply.

1.5.2 Planned opex

Our historical and forecast opex programme, by activity is illustrated below.

Nominal opex by expenditure category ($000)



Nominal opex by expenditure category ($000)	Current Period					Assessment Period	
Expenditure Categories	**FY08**	**FY09**	**FY10**	**FY11**	**FY12**	**FY13**	**FY14**
Emergency Maintenance	3,608	3,122	3,495	14,534	20,603	4,925	6,903
Scheduled Maintenance	10,443	11,887	12,577	9,045	7,910	16,210	18,009
Non-scheduled Maintenance	1,888	2,426	2,684	2,494	1,829	1,995	2,118
Network Management and Operations	8,410	8,712	9,498	10,122	11,795	13,681	15,989
General Management, Admin and Overheads	8,038	8,928	9,484	11,414	12,181	17,829	15,736
Total	**32,387**	**35,076**	**37,738**	**47,609**	**54,319**	**54,640**	**58,753**

	CPP Period				
Expenditure Categories	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Emergency Maintenance	7,311	9,197	8,092	8,443	8,810
Scheduled Maintenance	20,323	21,138	20,619	21,042	22,065
Non-scheduled Maintenance	2,250	2,394	2,502	2,614	2,732
Network Management and Operations	16,916	17,487	17,706	18,166	18,661
General Management, Admin and Overheads	14,406	15,025	15,965	16,154	17,584
Total	**61,205**	**65,242**	**64,884**	**66,419**	**69,852**

Our opex plans have been prepared consistent with our overarching asset management planning practices, which reflect our lifecycle management strategy for our electricity assets. We use condition based maintenance practices for our network equipment and this is reflected in this plan. We aim to manage our assets prudently to provide a reliable and appropriate quality service for the long term benefits of our consumers.

Our support activities, those not directly related to constructing, maintaining and renewing our electricity distribution system, support our core asset management processes. Our infrastructure team is responsible for developing and implementing our asset management policies and practices. Our corporate teams (corporate, finance, commercial, information technology (IT), human resources (HR), communications) provide the necessary systems, management support and direction to enable these functions to operate efficiently and effectively.

Our opex on network assets is dominated by scheduled maintenance. FY11 and FY12 are exceptions to this, and as illustrated above we incurred large emergency maintenance expenditure following the earthquakes in these years.

Our scheduled maintenance forecast increases in FY13 and continues to be higher than that we have spent pre-earthquakes. This reflects two key factors: the need to restore the condition of our damaged network assets; and the cost pressures we face in our local contract market due to the accelerating construction activity in Canterbury.

Our forecast opex also includes significant expenditure in network and corporate support services which are predominantly office based. This is represented by the network management and operations and general management, corporate and overheads opex categories.

1.5.3 Deliverability

We use a range of contracting resources to deliver our works plan. Our ability to respond so quickly to the unforeseen demands resulting from the earthquakes and re-prioritise our projects and programmes accordingly demonstrates the flexibility that we have available to us in our market. Notwithstanding the resources available we apply project prioritisation assessments when scheduling our planned works.

We are confident we can deliver the capex and opex programme we have included in this proposal. Our use of a number of contractors for field work is a core component of this deliverability objective. In addition we have recently increased and are continuing to increase our office based resources to provide the necessary planning, operations and contract management support for these projects.

1.6 Forecasting uncertainty

In applying for a CPP we are required to put forward detailed forecasts for a seven year period (ie: a two year assessment period and a five year regulatory period). Once a CPP proposal is submitted, and the Commission has completed its assessment, we are unable to modify our forecasts. This differs to our AMP planning process where we update our forecasts annually on the basis of further information and analysis.

Under normal circumstances, we would expect to be able to adequately manage forecasting uncertainty within a regulatory period. Indeed the five year DPP price path and quality standards require us to do so. However we are not currently operating under normal circumstances and new information is constantly emerging about the condition of our assets, the future needs of our consumers, our input costs and the development of the Canterbury region.

We have collated together all of the information we can reasonably acquire, and used our expertise and judgement to prepare the forecasts on which this CPP proposal is based. No doubt, information will emerge subsequent to submitting this proposal which, if incorporated, would cause us to modify our views and/or forecasts. This is the nature of the process however, and as we are constrained by the two year catastrophic event application window, we have proceeded with this application in good faith. It is therefore appropriate to consider the challenges which face us in committing to a long term plan during a period of unprecedented uncertainty.

Our expenditure forecasts include no contingency allowances other than an annual scheduled maintenance allowance of $1.5m (real) per annum over and above our asset specific scheduled maintenance forecasts. This allowance is regularly included in our AMP forecasts and is used to provide for uncertainties that impact maintenance (predominantly scheduled maintenance, but potentially also non-scheduled and emergency) expenditure. In addition in our corporate opex we have a special projects budget. This is an annual provision to accommodate responses to specific issues which may arise. For example this budget has been used to fund the preparation of our CPP proposal this year. In FY11 and FY12 it was directed to the abnormal costs we incurred in responding to the earthquakes.

We have included no provisions in our CPP proposal for future catastrophic events. Should we experience high impact events during our CPP regulatory period, which are unable to be accommodated in the CPP price path and quality standards, we will seek to re-open the Commission’s CPP Determination in accordance with catastrophic event provisions of the CPP IM.

The time constraints and our focus on rebuilding our network have resulted in a CPP proposal which concentrates primarily on our consumers’ needs, our associated investment requirements, our network performance, and the appropriate price and quality standards which are consistent with those needs. Accordingly we have not included in our proposal any efficiency sharing incentive mechanisms. While we might consider these when operating in more normal circumstances, we do not believe they are appropriate for us at this time given our primary focus is in returning to a business as usual position.

2 Introduction

2 Introduction

2.1 Summary

This section introduces Orion including our network supply area, our ownership, governance and organisation structures. In addition in this section we describe the Part 4 Commerce Act 1986 price and quality regulations which apply to us. We explain how default and customised price and quality standards are provided for under the Act. In addition we set out in some detail the regulatory provisions for CPPs, the processes for applying for a CPP and how the Commission will assess our proposal. We conclude with a summary of how our proposal meets the Commission's assessment criteria.

2.2 Background

2.2.1 Introduction

Orion owns the electricity distribution network servicing the Christchurch and central Canterbury region. The major earthquake activity experienced in Christchurch and surrounding areas since 2010 has resulted in considerable damage to Orion's network and reduced electricity demand due to disruption to the economic activity in the region. It has also caused significant damage to homes, particularly in the eastern suburbs of Christchurch.

This has been reflected in reduced revenues and higher costs for Orion. The damage to the network has also compromised its performance, resulting in more network outages than experienced before the earthquakes.

We note that over the years we have managed our business efficiently and prudently. We have insured our assets where it is economically viable to do so and we have invested to enhance the resilience and diversity of the network. Orion believes that the relative lack of earthquake-related damage to our key substations, and our effective responses to the earthquakes, have confirmed our asset management practices and meant that earthquake related costs and losses to Orion and our consumers have been minimised.

In addition, the earthquake effects are ongoing. Even though major emergency repairs are finished, there is still work ahead to build strength back into the electricity network. Continuity of electricity supply is absolutely vital to the future of the city. The most important contribution Orion can make to boosting both business and community confidence in Christchurch is to keep the power on where it is needed, quickly respond if supply is disrupted, and promptly provide accurate information during major power cuts.

These earthquake impacts and the need to build strength back into our network mean we have incurred and will continue to incur costs and losses that are not reflected in our current prices. We must invest appropriately in our network as the long term consequences of under investment are severe for consumers. Accordingly, Orion must now apply for modifications to the rules which determine how our revenue allowances and reliability targets are set.

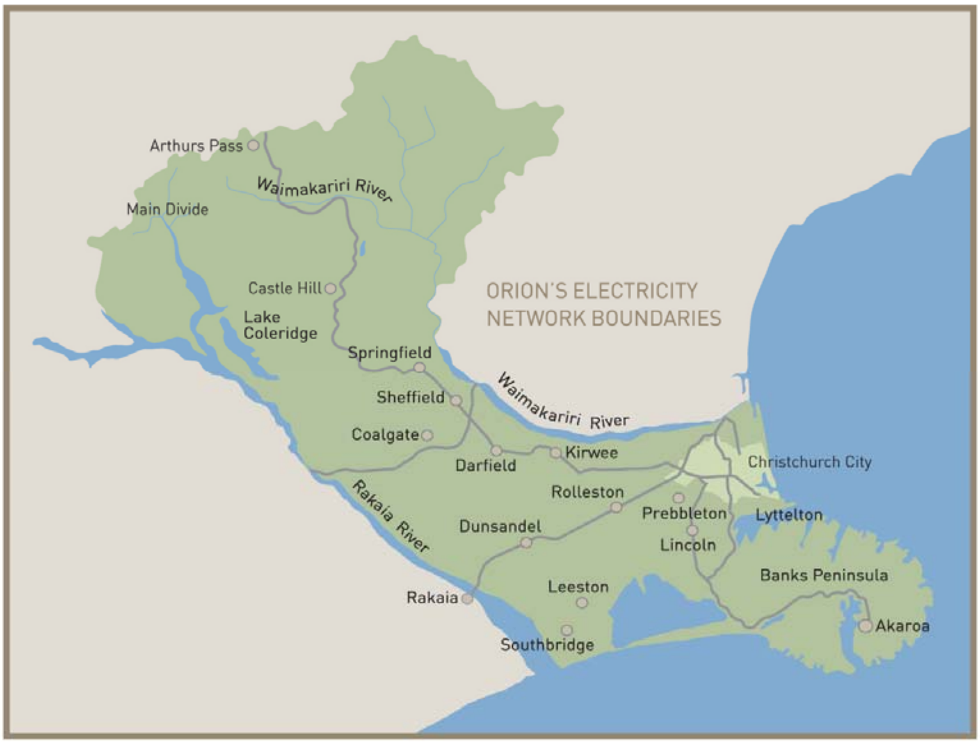
This document sets out Orion’s proposals for revenue allowances and reliability targets from 1 April 2014 to 31 March 2019, along with supporting explanations and evidence. Approval of the proposal will not affect prices until 1 April 2014. It has been prepared in accordance with the requirements for a CPP as set out in Part 4 of the Commerce Act 1986. These requirements are explained in Section 2.3 below.

The Commission will assess this proposal and consult with interested parties before making a CPP Determination as to the price path and quality standards which will apply to Orion over the CPP period.

2.2.2 Orion’s network

Orion’s electricity distribution network is located in central Canterbury between the Waimakariri and Rakaia rivers, and from the Canterbury coast to Arthur's Pass. Our network covers 8,000 square kilometres of diverse geography, including Christchurch city, Banks Peninsula, farming communities and high country.

The following map illustrates Orion’s supply area.



Orion’s network is fundamental to Canterbury’s social and economic well-being. We transport electricity from 15 Transpower grid exit points (GXPs) to more than 190,000 homes and businesses. With the exception of a few major consumers, we charge electricity retailers for this delivery service and retailers, in turn, charge homes and businesses. Retailers also charge consumers for the cost of generating electricity plus their retail charge.

The vast majority of our consumers – over 85% – are residential households. The rest are commercial or industrial premises. Business consumers use around 60% of the electricity delivered via our network, while residential consumers account for the other

40%. To reach all of our consumers, we manage a sophisticated network of electrical assets, load control equipment and multiple computer systems.

Our network is both rural and urban, with consumer densities ranging from an average of five connections per kilometre of line (excluding street-lighting circuit) in rural areas to an average of 26 per kilometre in urban areas. Approximately 90% of our consumers are located in the urban area of Christchurch with the remaining 10% in the rural area. We have some 320 major business consumers with loads between 0.3 MW and 5MW.

Network Summary	
Measure	**At 31 March 2012**
Number of consumer connections	190,682
Network maximum demand (MW)	633
Electricity delivered (GWh)	3,070
District/zone substations	52
Distribution/network substations	10,673
Kilometres of 66kV line and cable	200
Kilometres of 33kV line and cable	336
Kilometres of 11kV line and cable	5,657
Regulatory value of network assets ($m)	$844m

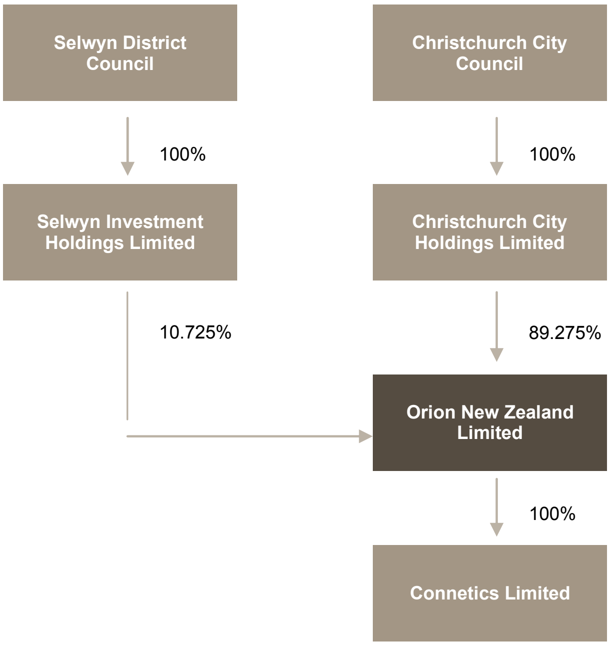
Further information about Orion can be found on our website http://www.oriongroup.co.nz

2.2.3 Ownership and governance

Orion is directly owned by Christchurch City Holdings Limited (CCHL) (89.275%) and Selwyn Investment Holdings Limited (SIHL) (10.725%). CCHL is the wholly owned investment arm of Christchurch City Council (CCC) and SIHL is the wholly owned investment arm of the Selwyn District Council (SDC). In simple terms, Orion's ultimate shareholders are CCC and SDC, who act on behalf of the local community, ie their ratepayers.

Orion also wholly owns the electrical contracting business, Connetics. Connetics contracts to construct and maintain substations, overhead and underground lines and associated equipment. The company also operates an equipment supply and distribution business and provides engineering design and consultancy services.

The following diagram illustrates our group structure.



Our directors are appointed by the shareholders to govern and direct the company's activities. The board is the overall and final body responsible for all decision-making within the company. Our board is responsible for the direction and control of the company including stewardship of commercial performance, business plans, policies, budgets and compliance with the law. The Board has approved a delegated authority policy that specifies actions which staff can take within set levels of expenditure without reference to the board. Anything significant outside of this policy is put before the board as required.

The board comprises the following members as at 31 December 2012.

- Chair, Craig Boyce
- Directors, Michael Andrews, George Gould, Paul Munro, Geoff Vazey.

Further information about Orion's Board can be found on our website at: http://www.oriongroup.co.nz/company-profile/company-directors

2.2.4 Statement of Intent

Orion is classified as an energy company in accordance with the Energy Companies Act 1992. Each year Orion publishes a Statement of Corporate Intent (SOI) which is prepared in accordance with section 39 of that Act and Orion's constitution. The SOI sets out the nature and scope of the activities we undertake, our objectives and our key performance targets.

Section 36 requires Orion, as its principal objective, to operate as a successful business. This means that Orion is obliged to ensure the company achieves a fair, but not excessive return on its shareholders' investment. In addition, Orion seeks to:

- achieve our objectives, both commercial and non-commercial, as specified in the SOI
- be a good employer

- exhibit a sense of social and environmental responsibility by having regard to the interests of the community in which we operate
- conduct our affairs in accordance with sound business practice.

As set out in our SOI our top priority is the efficient and effective management of our electricity distribution network. We aim to provide consumers with a high level of service, a reliable and secure supply at an efficient and cost effective price.

The SOI is reviewed annually in consultation with our shareholders and covers a three year period. Our most recent SOI was published in March 2012 and covers FY13, FY14 and FY15. A copy of our most recent SOI can be found on our website at: http://www.oriongroup.co.nz/publications-and-discloures/statement-of-intent

Our next SOI, covering the three years FY14, FY15 and FY16 will be available in March 2013.

2.2.5 Management and organisation structure

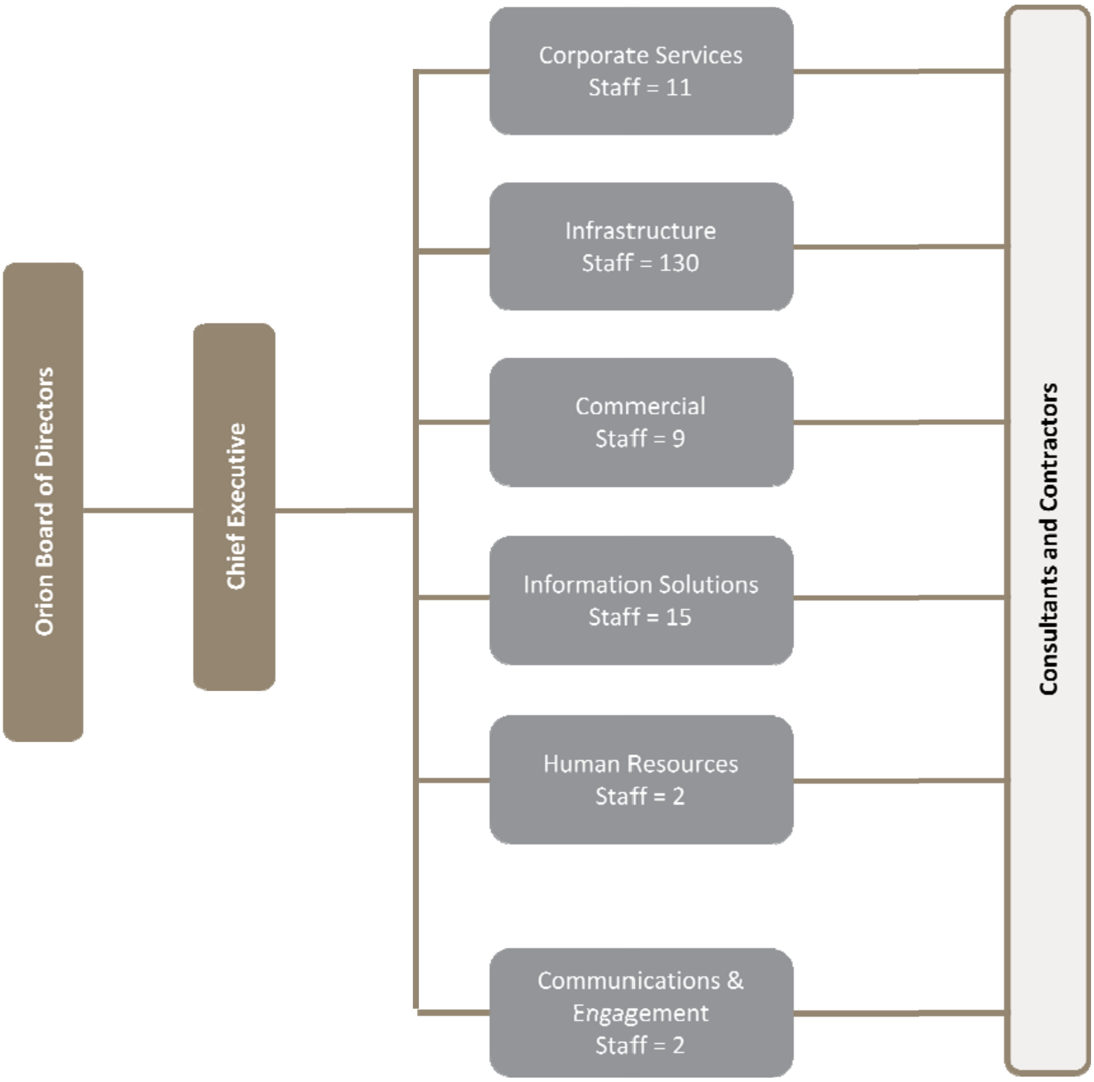
Orion's corporate management team is headed by Rob Jamieson, CEO. The following table sets out the members of the team and their responsibilities.

Corporate management team	
Executive	**Role**
Rob Jamieson Chief Executive Officer	Rob was appointed Orion's chief executive officer in August 2011. He has worked for Orion since 1994 in various capacities, most recently as General Manager Commercial.
Gina Clarke Communications And Engagement Manager	Gina manages the communications and engagement functions at Orion, responsible for consumer and stakeholder relationships, consultation and seeking consumer feedback on service performance.
David Freeman-Greene General Manager Commercial	David leads Orion's commercial team, which manages regulatory matters and compliance, industry relationships, pricing, billing, investment analysis and consumer relationships.
Brendan Kearney General Manager Corporate Services	Brendan leads the Orion corporate services team, which is responsible for the corporate and finance functions of the business. Brendan is also a director of Connetics Limited.
Craig Kerr General Manager Information Solutions	Craig manages the information solutions function within Orion, which delivers information solutions infrastructure and provides and enhances information systems to support Orion's business processes.
John O'Donnell Chief Operating Officer	John leads Orion's infrastructure team, which manages the safe construction, maintenance, engineering and operation of Orion's network.
Adrienne Sykes Human Resources Manager	Adrienne is responsible for the human resources function of Orion, working at both strategic and operational levels within the company.

Further information about Orion's corporate team can be found on our website at: http://www.oriongroup.co.nz/company-profile/company-managers

Overall management of our network assets is undertaken at our Christchurch office. Our main office has been demolished following earthquake damage and we are currently working from temporary accommodation on site. We are proceeding to build new offices to IL4 lifelines standard at another location.

The following chart sets out Orion's organisation structure. At October 2012 we had 169 full time employees.



We summarise the main responsibilities of each of our corporate groups below.

Corporate Groups	
Group	**Responsibility**
Corporate Services	Our corporate services group is responsible for supporting the other corporate groups in areas such as:

	• reporting to the board and shareholders, including regulatory and statutory requirements • insurance and financial planning • treasury management • debt management • creditor processing • tax obligations • financial accounting systems • payroll • fleet management
Infrastructure	We maintain in-house technical and administrative competence within our infrastructure group to: • manage risk to our assets as well as operational and environmental risk • manage and develop asset and network policies along with design and construction standards • scope network extension and maintenance work and prepare budgets • review designs and prepare contract documents for tendering work • manage projects/contracts and interact with contractors • maintain strategic asset records and reliability statistics • manage and monitor the network • manage corporate property • manage safety and environmental compliance systems • assess new technologies • monitor asset emergency spares and supply systems • ensure that security and reliability levels are maintained when expansion is required to meet load growth • conduct load analysis and forecasting, asset capability monitoring and contingency planning • liaise with significant stakeholders who shape the development of our region • interface with Transpower over technical connection issues and provision of future national grid capacity • provide technical support on protection and control systems development, power quality and technical standards • investigate the potential and impact of embedded generation in our network e.g. diesel and wind generation • introduce new business initiatives associated with demand side management • provide consumer call answering and distribution network fault management services
Commercial	Our commercial team is responsible for: • pricing, billing and contracts with retailers • relationships with economic regulators (such as the Electricity Authority

	and Commerce Commission) • compliance with the industry rulebook • commercial contracts with Transpower • advice to retailers and major consumers
Information Solutions	Our information solutions team is responsible for: • delivery and management of our information systems infrastructure • the provision, support and enhancement of information systems that support our business processes • managing our SCADA system
Human Resources	Our human resources team is responsible for: • human resource strategy development and implementation • human resource advice and support • employment-related compliance
Communications and Engagement	Our communications and engagement team is responsible for: • communications planning and implementation • consultation and engagement on substantial projects • managing Orion's brand

Consultants and contractors

We contract in the services of consultants and contractors to assist us fulfil our obligations, particularly in relation to capex and maintenance. They do not have any management responsibilities, but operate on a fixed scope and/or period contracts to meet the specific needs of our project or programme requirements. Further information about our use of contractors is set out in Sections 8.5.5 and 9.11.2 of this proposal.

2.3 Regulatory overview

2.3.1 Regulatory regime

We are subject to a wide range of legislation. Our aim is to achieve compliance with all relevant legislation, regulations and codes of practice that relate to how we manage our electricity distribution network. Key legislation of relevance to our business includes the following:

- Building Act
- Civil Defence Emergency Management Act
- Commerce Act
- Electricity (Hazards from Trees Regulations)
- Electricity Act
- Electricity Amendment Act
- Electricity Industry Act
- Electricity Reform Act
- Electricity Regulations
- Energy Companies Act

- Health and Safety in Employment Act
- Local Government Act
- NZ Codes of Practice
- Public Bodies Contract Act
- Public Works Act
- Resource Management Act.

2.3.2 Commerce Act

The provision of the electricity lines services provided by Orion is regulated under Part 4 of the Commerce Act 1986, which is administered by the Commission. Orion is subject to Information Disclosure (ID) regulation and price-quality regulation which embodies DPPs and alternative CPPs for those suppliers which require more business specific price and quality terms.

Currently Orion's price limits are determined by the DPP price path which commences with weighted average prices as at 31 March 2010, with allowance for annual price escalation equivalent to the CPI, and full recovery of transmission costs, industry levies and local body rate expenses. Quality limits are based on Orion's historical (FY05-FY09) network reliability performance.

Each DPP is to apply for a period of five years, before being reset. In normal circumstances the next reset would be at 1 April 2015. However the Commission has recently determined a number of input methodologies (IMs) which impact on how regulatory profit is measured. An assessment of regulatory profit is an important component of determining the allowable price path under the DPP. Part 4 of the Commerce Act provides for a one-off mid period reset to incorporate the impact of the IMs, should they result in a materially different price path.

The Commission has recently determined a mid period DPP reset for all EDBs which are subject to the DPP, with the exception of Orion. This is to apply from 1 April 2013 and prescribes new price limits, but no changes to the quality standards. A further DPP reset will be made at 1 April 2015, at the end of the current DPP period. That reset will apply for a period of five years, to 31 March 2020 and will involve new price and quality standards for all EDBs which are subject to the DPP.

The current DPP has not been reset for Orion. This is because the DPP reset is unable to accommodate the unique and specific circumstances which we have faced since the earthquakes.

Orion must therefore apply for a CPP. A CPP is expected to provide Orion with a different price path and different quality standards than those which would otherwise apply under this current DPP and the next DPP. When the CPP regulatory period ends, Orion is able to choose whether to move back to the DPP, or apply for another CPP.

2.3.3 CPP input methodology

The IMs which apply to EDBs include methodologies for CPPs. These methodologies prescribe the information which must be included in a CPP proposal, the processes which must be followed by Orion when preparing its proposal, the methods Orion must use when calculating its proposed CPP price path and quality standards and how the

Commission will assess a CPP proposal. The CPP IM, which incorporates these methods, aims to ensure fair prices and quality standards which meet the long term interests of consumers.

Additional requirements for CPPs are set out in Subpart 4 of Part 4 of the Commerce Act 1986. These include timeframes for applying and assessing CPP proposals, what a CPP may include, and what happens when a CPP ends.

Orion's CPP proposal has been prepared in accordance with these requirements. By ensuring our CPP proposal is consistent with the CPP methods we are adopting an approach which we believe is fair for our consumers.

2.3.4 CPP application process

Prior to submitting a CPP application for consideration by the Commission, Orion must:

- appoint an independent verifier, who must be approved by the Commission
- obtain a verification report which must set out the verifier's opinion on Orion's service categories, opex and capex forecasts, policies, planning standards, demand forecasts, key assumptions, input data and the forecasting methods used in determining forecast demand and capex and opex requirements. In addition the verification report must identify the areas of the proposal and information the Commission should focus on when undertaking its assessment
- obtain an independent engineering review of Orion's proposed quality standard
- consult with consumers as to the likely price and quality impacts of the proposal should it be accepted by the Commission
- advise consumers of the Commission's assessment and consultation processes following a CPP application
- obtain an audit report as to the compilation and material accuracy of the information in the proposal, including whether the information complies with the CPP IM
- obtain director certification in support of the CPP application.

Orion has completed all of these requirements.

Section 6 describes our proposed quality standard and the independent engineering review we have obtained, which supports it. A copy of this report is included in Appendix 3.

Our CPP application includes the necessary directors' certificates, audit and verification reports and consumer consultation evidence. In this CPP proposal we have considered the feedback provided to us from consumers and other interested parties, the verifier and our auditor. We believe our proposal has benefited from this input and we have attempted to respond to the comments made, as fully as possible, within the time available to us.

2.3.5 What happens next

After submitting our CPP proposal, the Commission starts its assessment process. Within 40 working days the Commission will assess whether our proposal complies with the CPP IM, including whether it contains all of the required information. If the CPP does not comply with the CPP IMs the Commission may at its discretion:

- discontinue any consideration of the proposal; or

- request further information from Orion and receive responses within a further 40 working day period.

At the end of that period the Commission will determine whether or not its assessment of the CPP proposal will proceed. Assuming this is the case, the Commission then has a further 150 working days to make its CPP Determination. During that time it will seek submissions from interested persons and consider those submissions. The final CPP Determination will include a price path and quality standards which may be higher or lower than those Orion has proposed. It is expected that the CPP Determination for Orion will come into effect on 1 April 2014.

2.3.6 Assessment criteria

Orion's CPP proposal is to be assessed with reference to the following criteria:

a) whether Orion's CPP proposal is consistent with the methodologies specified in Part 5 of the Commerce Act (Electricity Distribution Services Input Methodologies) Determination
b) the extent to which a CPP in accordance with Orion's CPP proposal would promote the purpose of Part 4 of the Commerce Act (refer below)
c) whether data, analysis, and assumptions underpinning Orion's CPP proposal are fit for the purpose of the Commission determining a CPP under section 53V of the Commerce Act, including consideration as to the accuracy and reliability of data and the reasonableness of assumptions and other matters of judgement
d) whether proposed capital expenditure and operating expenditure meet the expenditure objective (refer below)
e) the extent to which any proposed quality standard variation better reflects the realistically achievable performance of Orion over the CPP regulatory period, taking into account either or both -
    i. statistical analysis of past outage duration (measured as SAIDI) and outage frequency (measured as SAIFI) performance
    ii. the level of investment provided for in proposed maximum allowable revenue before tax, as the case may be
f) the extent to which -
    i. Orion has consulted with consumers on its CPP proposal
    ii. Orion's CPP proposal is supported by consumers, where relevant.

Purpose of part

Criterion b) above refers to the purpose of Part 4 of the Commerce Act. The purpose of Part 4 is set out at section 52A as follows:

> 52A Purpose of Part
>
> (1) The purpose of this Part is to promote the long term benefit of consumers in markets referred to in section 52 by promoting outcomes that are consistent with outcomes produced in competitive markets such that suppliers of regulated goods or services -
>   (a) have incentives to innovate and to invest, including in replacement, upgraded, and new assets; and
>   (b) have incentives to improve efficiency and provide services at a quality that reflects consumer demands; and

(c) share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices; and
(d) are limited in their ability to extract excessive profits.

Expenditure objective

Criterion d) above refers to the expenditure objective, which is defined in the CPP IM as follows:

> The expenditure objective means the objective that capital expenditure and operating expenditure reflect the efficient costs that a prudent non-exempt EDB would require to -
>
> (a) meet or manage the expected demand for electricity distribution services, at appropriate service standards, during the CPP regulatory period and over the longer term; and
> (b) comply with applicable regulatory obligations associated with those services.

2.3.7 Assessment against criteria

We have considered these criteria in preparing our proposal and believe we have fully met the requirements set out above. Our approach to each of the assessment criteria and identification of relevant supporting evidence is summarised in the following table.

How our CPP Proposal addresses the Commission's assessment criteria

Criterion	Our proposal	Supporting evidence
a) Consistent with IMs	Our proposal applies all of the IMs as intended	Audit NZ Audit Certificate, Directors' Certificate, Verifier's Report, Independent Engineer's Report
b) Promote Purpose of Part 4	Our proposal specifically considers the long term needs of our consumers by ensuring sufficient and efficient investment is made to restore and maintain network resilience, by providing for significant improvements in network reliability over the CPP period, by smoothing the price impacts over a number of years and by ensuring Orion's shareholders earn returns which are commensurate with, and no more than, the risks associated with our business	Jeff Balchin's (PwC) Independent Expert Report (Appendix 1), James Mellsop's (NERA) Independent Expert Report (Appendix 2), Richard Gibbon's (Linetech Consulting) Independent Engineering Review Report (Appendix 3), along with the explanations and evidence included throughout this proposal
c) Information provided is fit for	Our proposal contains robust and comprehensive information which	Audit NZ Audit Certificate, Directors' Certificate, Verifiers

purpose	addresses all of the IM requirements. We have included our rationale for any judgements or estimates we have made. We have sought independent review of the information included	Report, Independent Engineer's Report (Appendix 3) along with the detailed information presented in this proposal in particular Sections 6, 7, 8 and 9, and our summary of compliance (Appendix 4)
d) Proposed capex and opex meets expenditure objective	Our capex and opex plan reflects our detailed planning processes, a careful assessment of the short term and long term needs of our consumers and our legislative obligations based on the knowledge and information we have available to us at this time	Evidence set out in Sections 8 and 9 of this proposal, and supporting material identified throughout those sections along with the Verifier's Report
e) Quality standard variation reflects realistically achievable performance	Our proposed quality standard variation specifically recognises our immediate challenge to restore our network resilience following the Canterbury earthquakes	Independent Engineer's Report (Appendix 3), along with evidence set out in section 6 of this proposal
f) Consultation with consumers	Our proposed quality standard which aims to restore our pre-earthquake network quality standards is consistent with feedback from our consumers. Our proposed price path accommodates consumer concerns regarding price increases by spreading the impact over a ten year period, and deferring cost where practicable.	Summary of consultation set out in our CPP application, further discussion included in Sections 6 and 7 of this proposal

2.4 Appendices and supporting documents

Section 2 – Appendices	
Appendix	**Title**
1	PwC Report on Catastrophic Event Cost Recovery
2	NERA Peer Review of PwC Report
3	LineTech Consulting Report on Proposed Reliability Standards
4	Satisfaction of CPP IM information requirements

Section 2 – Supporting Documentation
Title
Statement of Corporate Intent

3 Reasons for proposal

3 Reasons for the proposal

IM 5.4.2

3.1 Summary

This section describes the major earthquakes which have hit Canterbury since September 2010. It includes a description of the damage to our network, our preparation in advance of these catastrophic events and how we responded. We also quantify the impact of the earthquakes on our costs and revenue and our network reliability performance.

This section also includes a description of our DPP price and quality standards, the Order in Council (OIC) option we investigated in 2011 and our decision to apply for a CPP.

The key reasons supporting our decision to apply for a CPP may be summarised as follows:

- Canterbury has been hit by catastrophic earthquakes over a prolonged period which commenced on 4 September 2010. Evidence and explanations demonstrating the impact of those earthquakes on Orion and the wider Canterbury community are included in this proposal
- as a result, our revenues have fallen and costs have increased
- our network resilience and reliability has been impaired and we are unable to meet our DPP quality standards
- accordingly we must now invest in our network to restore its resiliency and regain reliability standards which meet the needs of our consumers
- our prices are currently regulated under the DPP, and these are insufficient for us to recover our costs and earn a fair return on our assets. While we had prudently insured our assets to the extent economically viable, it is not possible to fully insure lines and cables and we therefore must recover our costs on an ex-post basis from consumers. The DPP price path does not include allowances for the impact of catastrophic events.

This CPP proposal therefore seeks a new price path and new quality standards which better meet our post-earthquake circumstances, than those which currently apply to us under the DPP.

The remainder of this section of the proposal is structured as follows:

- Section 3.2 describes the earthquakes
- Section 3.3 explains the impact of the earthquakes on Orion
- Section 3.4 describes the OIC option we pursued prior to preparing this CPP application
- Section 3.5 describes the DPP price and quality regulation which otherwise applies to us
- Section 3.6 documents our decision to apply for a CPP
- Section 3.7 explains our approach to the CPP application
- Section 3.8 summarises the key evidence contained in the CPP proposal

- Section 3.9 lists the appendices and other supporting documents which support Section 3.

3.2 Earthquakes

On 4 September 2010 Canterbury was hit by a 7.1 magnitude earthquake. The earthquake had an epicentre near Darfield, about 40km west of Christchurch City. There were no fatalities as a result of this earthquake, which is believed to partly reflect the fact that the earthquake occurred in the early morning, and was centred in a rural location. There was however widespread damage to infrastructure. Many masonry buildings, which were largely unreinforced, sustained damage. In addition the eastern suburbs of Christchurch and Kaiapoi township were seriously affected by liquefaction and lateral ground movement.

An aftershock sequence of more than 12,000 aftershocks of varying magnitude began that day and is ongoing. All of the earthquakes experienced since are the result of ruptures on faults not known to be active prior to the September 2010 earthquake.

Major earthquakes followed, the most notable being the deadly and devastating 6.3 magnitude earthquake on 22 February 2011 that struck near Lyttelton on the Port Hills, the 6.3 and 5.7 magnitude earthquakes of 13 June 2011 and the 5.8 and 6.0 magnitude earthquakes of 23 December 2011. The event on 22 February was by far the most serious, resulting in 185 deaths. The fault that ruptured was at a shallow depth and had an epicentre in the Port Hills, just to the south of Christchurch. In the worst-affected suburbs, houses and businesses were without power, water and sewerage for some time, and roads were damaged and unsafe. The Government declared a State of National Emergency in New Zealand on the day following the 22 February 2011 Christchurch earthquake which remained in place for almost nine weeks. This is the first State of National Emergency in New Zealand's history following a civil defence emergency, illustrating the unique circumstances Orion is working in.

The 22 February earthquake had devastating consequences. Two buildings collapsed catastrophically, where 133 people lost their lives and others were seriously injured. Failure of other buildings along with rock falls and other consequences caused the deaths of 52 people and many injuries.

As a result of the earthquakes, the CBD was also altered irrevocably. By mid 2012, CERA estimated that more than 650 buildings had been demolished in the CBD. It is projected that the total number of demolitions will be about 1100. In addition, over 7,000 houses are to be demolished. This widespread destruction not only has a severe economic impact on Canterbury, it has also imposed significant social and cultural costs to our region.

The following photo taken from the Port Hills a few minutes after the 22 February earthquake shows the scale of the destruction, with dust rising from falling masonry.

Christchurch City immediately following the 22nd February 2011, 6.3 magnitude earthquake

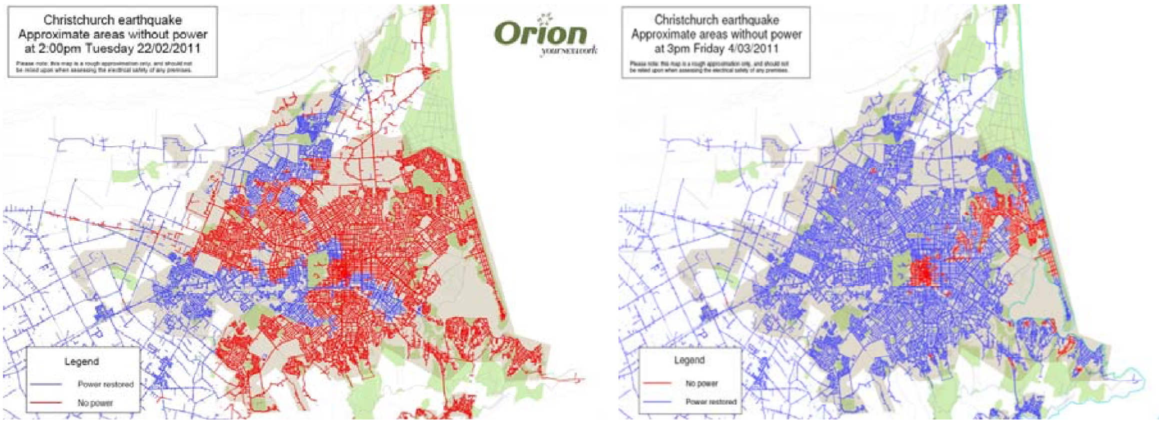
3.2.1 Immediate impacts on our network

On 4 September 2010, more than 150,000 consumers lost power. This is approximately three quarters of our consumer base. 90% of these had their power restored by nightfall that same day, and by the end of the week, supply was restored to virtually all consumers.

The damage caused by the February 2011 earthquake was about ten times greater than the September 2010 earthquake and approximately 20 times as severe as the most significant natural event to have previously occurred in Canterbury, a severe snow storm in 1992. Approximately two thirds of consumers lost power in the February 2011 earthquake. By the end of the next day we had restored power to 50% of our consumers; by the end of the week 86%; and within ten days 95%. With the exception of cordoned areas (and feeders originating within cordoned areas), we restored all consumers that wanted power within 24 days.

The extensive impact across our network is illustrated in the following diagrams.

Approximate areas without power on the day of the February 2011 earthquake and ten days later



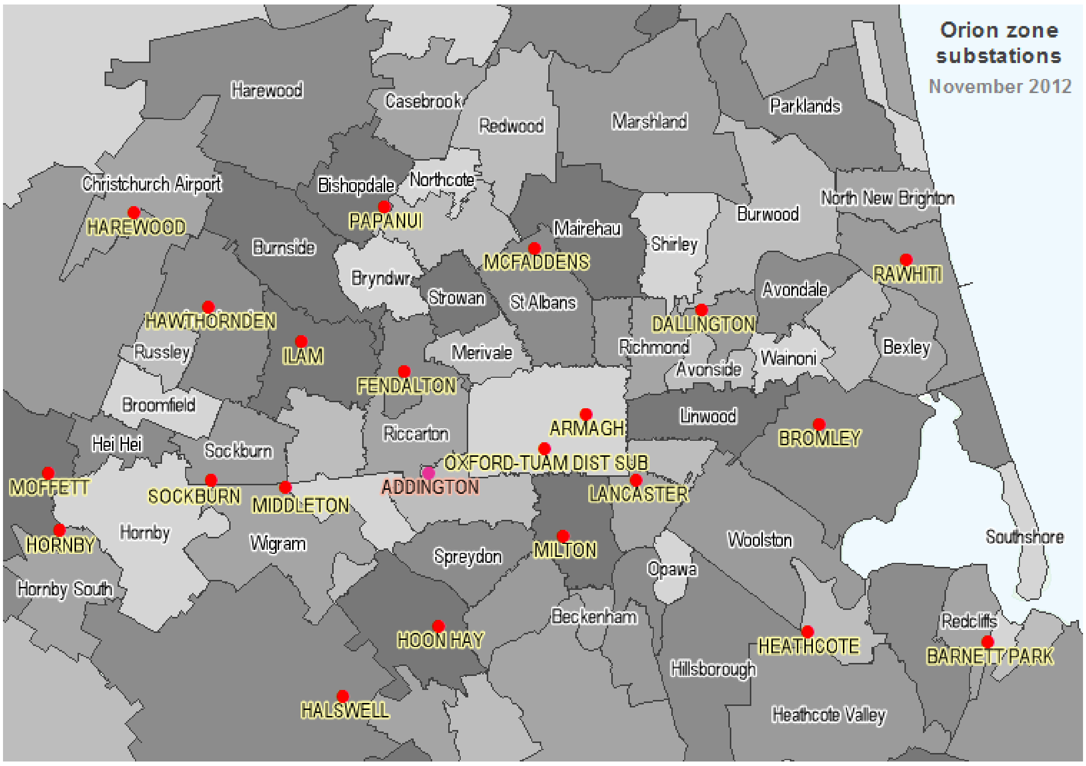
The 13 June 2011 earthquakes caused 56,000 consumers to lose power. 99% were restored within 48 hours. The 23 December 2011 earthquakes caused 31,000 consumers to lose power. 99% were restored by nightfall.

3.2.2 Damage to our network

Following the 4 September 2010 earthquake our network sustained the following damage:

- Greendale, Pages and Brighton zone substations were damaged, but remained operational. Minor damage was also incurred in other substations but seismic strengthening work undertaken previously prevented significant damage
- distribution buildings, kiosks, and associated transformers and switchgear sustained minor damage. Buildings had been strengthened and damage was confined to some cracking in walls and floors. There was also a few instances of ground subsidence
- damage occurred to underground cables in areas where ground moved laterally, mostly in the Brighton, Dallington and Avondale areas. The 66kV cables crossing the Avon River at Dallington were damaged but remained functional. Damage to 66kV cables at Brighton was also suspected, and these cables were down-rated. Multiple faults occurred in approximately 30 (4%) of the 11kV underground cables, particularly older cables. Some cable failures occurred in the CBD due to building damage
- overhead 66kV towers and poles appeared undamaged. Some insulators and binders were damaged along 33kV lines and rural 11kV lines. In addition some poles moved and pole foundations were damaged due to liquefaction and ground movement.

Our urban supply area showing the location of substations



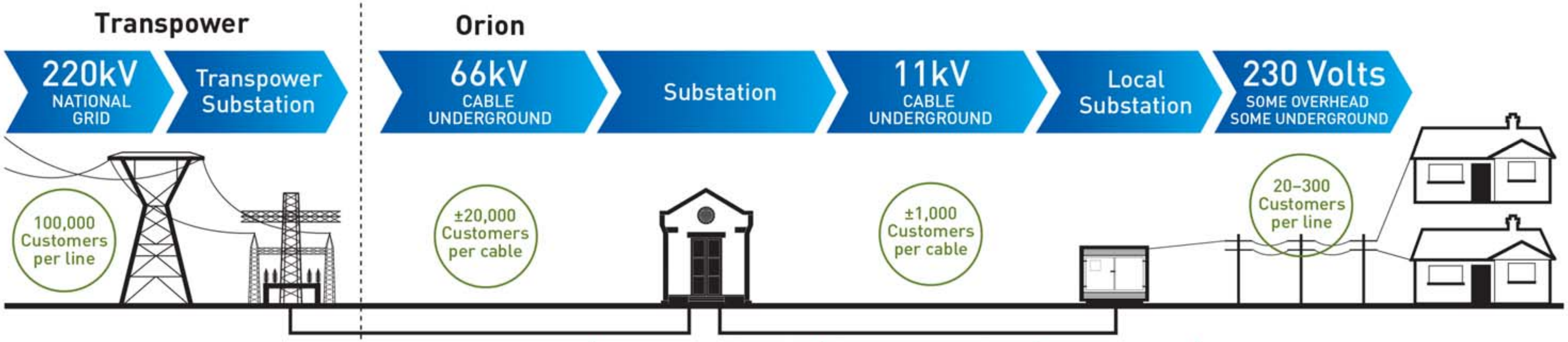
The February 2011 earthquake was considerably more destructive, severely damaging properties and infrastructure throughout the eastern suburbs of Christchurch and forcing the virtual abandonment of the central business district. A significant portion of the central business district remains off-limits. The most extensive network damage was to the underground cables in the north east suburbs of Christchurch. Four 66kV underground cables in this area were damaged beyond repair and the 11kV underground cables in the area also suffered many faults. Massive lateral forces caused more faults on the underground network than we would normally see in a decade. We anticipate that some damage to our underground cables may not become apparent for some time. The most significant damage comprised:

- major damage to the underground network as 50% of 66 kV cables suffered damage. The 66 kV cables supplying the Dallington and Brighton substations failed and damage also occurred to the Armagh Street 66kV cables
- 10 per cent of 11kV cables suffered multiple damage
- a small amount of damage impacted LV cables
- the New Brighton zone substation was lost due to liquefaction, as water up to 0.5 meters entered the substation building
- one substation suffered extensive ground failure, two further substations were damaged by rock fall and a few kiosks moved
- damage to overhead lines was light with approximately 80 poles moving.

Damage was compounded by the 13 June 2011 and the 23 December 2011 earthquakes. These aftershocks caused around 10 times the number of underground cable faults per week that we would usually have seen pre-earthquakes. We experienced 130 11kV cable faults. No damage was incurred on the 66kV cables.

A summary of the damage that our network suffered in the February 2011 earthquake is shown graphically overleaf.

Impact and response following the 22 February 2011 earthquake



- 50% of cables damaged – 30km out of a total of 60km
- Built two temporary 66kV overhead lines from Bromley to New Brighton and Dallington to replace four underground cables which were damaged beyond repair

- Four of 314 substations severely damaged
- Built a new major substation in Keyes Road, New Brighton to replace the damaged Pages Road substation
- Assessing options to repair or replace the other three damaged substations

- 15% of cables damaged – 330km out of a total of 2,200km
- 1000+ faults
- At least 12 hours of work needed to repair each fault
- 95% of all known faults have been repaired

- Some damage
- 4,500 local sub-stations being individually assessed – some have moved

- Some damage, including cracked insulators and poles affected by liquefaction
- Repairs are underway – it will take three to five years to find and fix all the damage

- Badly damaged buildings need to be disconnected before we start repairs

The following images illustrate the ways in which our network was affected by the larger earthquakes.

66kV underground cables stretched and broke through ground movement

11kV cables were similarly damaged

Substation buildings were badly affected by liquefaction

Poles also moved due to lateral spread

Flooding caused by liquefaction inundated some substations

3.2.3 How we prepared for an earthquake

Over the last 20 years risk mitigation has been an important part of Orion's planning. We believed that a network planned for resilience could play an important part in the rapid resumption of electricity services post a disaster. As it turned out we were unfortunately proven right.

Over the years, in collaboration with national grid owner Transpower, we engineered a strong electricity supply network for Canterbury. Where risk to the power supply couldn't be easily eliminated we controlled the level of risk through the use of emergency training, staff competency, safe work practices, planning and network design. For instance, rather than have a single line or cable into an area, we have multiple links, so if one fails, there is an alternative power supply route. This meshed approach to network architecture is one used most often in urban networks and it greatly increased our ability to restore power promptly after the earthquakes.

Also, as part of our risk mitigation planning, during the mid-1990s Orion participated in an 'engineering lifelines' study into how natural disasters would affect Christchurch. That study prompted us to spend $6m on seismic-protection and strengthening work. This included:

- reinforcing bridges carrying cables across rivers
- strengthening our substation buildings, many of which are of an older brick construction type
- bolting down transformers, a lesson from the 1986 Edgecumbe earthquake
- other minor preventative measures such as tying the batteries used for control systems to substation walls.

Investment in technology also assisted us during the earthquake response. For instance we installed innovative wireless communications equipment that continued to operate throughout the earthquakes. This technology helped us restore power in rural Canterbury sooner that we otherwise would have been able to.

Also, our commercial incentives to large electricity consumers, such as hospitals and the Police, had encouraged them to install diesel generators and use them during periods of peak power demand. This meant many were well prepared with back-up power supply that worked when earthquakes struck.

Prior to the earthquakes, we developed and maintained 'Mutual Aid Partner' agreements with other electricity distribution companies to provide support in situations where a network was affected by a large scale natural disaster. This prearranged support was vital in the aftermath of the February 2011 earthquake.

In addition, we regularly contributed to emergency readiness programmes run with Civil Defence and other utility organisations. Participating in these exercises enabled Orion to test its emergency processes and procedures and make improvements from any key lessons learnt.

An independent study, ‘The Value of Lifeline Seismic Risk Mitigation’ commissioned by the Earthquake Commission, reported that Orion's earthquake-strengthening work and planning resulted in substantial of repair and replacement costs being avoided by Orion. Avoided detriment to Canterbury's economy was estimated at many times more.

We note that our pre earthquake planning was informed by our proximity to the Alpine fault. The recent earthquakes were not associated with that fault. It is expected that earthquake activity will arise as a consequence of the Alpine fault at some stage in the future. We need to be prepared for that.

3.2.4 Our response

Our responses to the earthquake damage involve:

- repairs where economic
- replacement where repairs are not economic or where repairs cannot occur quickly
- temporary alternatives where replacement cannot occur quickly
- planned projects brought forward to improve network capacity and security of supply to areas where our network is still vulnerable
- new diesel generator sets to provide backup power supply.

In the following paragraphs we describe our immediate responses to each of the major events which have occurred since September 2010.

September 2010

Orion’s control centre located in Manchester Street suffered little damage in September 2010 and no failure of control systems occurred. Additional staff started arriving at the control centre within 30 minutes of the earthquake. An initial visual assessment indicated that assets sustained only limited damage. This proved accurate and the majority of the network was quickly restored.

February 2011

Our head office buildings were badly damaged in the February 2011 earthquake and we were forced to relocate to our ‘hot site’. The hot site is a live and operational network control centre that we maintained for such an emergency. In addition to our regular contractors, we soon had more than 240 extra fault staff working on repairs. These additional resources came from our mutual aid partners (other EDBs), and local electrical contractors. We were also able to divert resources from planned work to fault restoration.

Our initial focus was on isolating damaged properties at the request of consumers or under the instruction of emergency services. Over the first few days we identified a number of areas where we were unable to restore supply quickly due to the degree of damage to underground cables. In these instances it was necessary to isolate faults and use temporary generators to restore supply as quickly as possible, prior to repairing cables.

Orion's (now demolished) head office post February 2011

We sourced additional generators from other providers and EDBs. At one point we had 24 generators operating to supply electricity to 10,000 consumers. We were able to progressively remove the generators once damage was repaired with the last being removed in mid April 2011, nearly 2 months after the earthquakes.

Our immediate major recovery initiatives included building a new substation in Rawhiti Domain in New Brighton to replace the severely damaged Pages Road substation. The new substation began to supply load to consumers in early July 2011.

We also built two temporary 66kV overhead lines to bypass the damaged underground cables. The first temporary line extends from the Transpower GXP in Bromley to Pages Road substation and from there to our new Rawhiti substation, over a distance of four km. The second temporary line also starts at the Transpower GXP in Bromley and extends to our Dallington substation, a length of four and a half km. These lines were needed to keep power on to 20,000 consumers in north-east Christchurch, until a permanent supply from Bromley to the existing Dallington substation, and the new Rawhiti substation is completed in 2014.

June and December 2011

The June and December 2011 earthquakes weren't so damaging, although our head office building sustained further damage. This fully insured building has since been demolished and we are operating from a temporary site until permanent offices are built. On the network, fault levels have been higher than normal since the earthquakes and it is expected that further cable damage may yet be discovered. It is also expected that earthquake damage to overhead lines will emerge over time. This is consistent with our expectations that we will move into a recovery phase once the immediate consequences have been addressed. Recovery is the final 'R' of our '4 Rs' risk management philosophy which incorporates Risk Reduction, Readiness, Response and Recovery. We anticipate our Recovery activities will take many years.

Current network status

All of our major emergency repair work was completed by September 2011. During this time we were also responding to normal outage events, which were not related to the earthquakes, such as weather and third party interference.

Residents and businesses across our network area (except in the CBD red zone) could use power as normal from September 2011. We have also installed diesel generators in the north east of the city, and have a number of others on standby.

As the majority of our network repair and enhancement responses to the earthquakes are now completed or underway, our priority is to return our network to an acceptable level of resiliency and security. In addition we have commenced building new offices, to an IL4 lifelines standard, consistent with our obligations under the Civil Defence Emergency Act. Our current temporary office building is due to be demolished as part of the CERA CBD development project.

The earthquakes have tested our security of supply standards, our policies, our investments and our procedures. Over the years we have invested to enhance the resilience and diversity of the network. Orion believes that the relative lack of earthquake-related damage to our key substations, and our effective responses to the earthquakes, have confirmed our asset management practices.

We engaged Kestrel Group to independently review our preparedness for our response to the earthquakes and they have endorsed our approach. The Kestral Group are experts in emergency management, business continuity and crisis management.

The main conclusions drawn by the Kestral Group are:

- Orion's management approach, featuring systematic and sustained investment in seismic mitigation, was central to rapid and effective electricity restoration
- since the September earthquake, Orion has demonstrated an ongoing willingness to seek self-improvement
- the importance of maintaining safety as a top priority despite the pressure of work.

In addition, the report makes the following observations in its Executive Summary:

- for many years, Orion has actively sought continued service improvements to meet consumer needs. Orion's approach has included identifying and initiating work to improve network resilience so as to minimise economic impacts caused by outages including outages caused by earthquakes
- the improvement programme can be traced back to the mid-1990s Christchurch Lifelines report: 'Risks and Realities'. This report led to the inception of an ongoing seismic strengthening programme that commenced in 1996 and progressed systematically each year

- since the mid 1990s, Orion has invested $41 million in increasing the resilience of its network, learning from events such as the 1987 Edgecumbe earthquake and from engineering and geotechnical assessments. All new structural assets and existing strategic structural assets, e.g. subtransmission lines and zone substations, are designed to withstand a 500 year seismic event with little or no service disruption
- the seismic strengthening component cost $6 million, an investment Orion has estimated to have saved Orion $60 to $65 million in direct asset replacement costs in the earthquakes. The balance between costs and benefits is even more pronounced when societal benefits (i.e. gains to the community that don't appear in Orion's accounts) are taken into account
- Orion and Orion's contractors worked effectively to restore electricity as rapidly as possible following the earthquakes. Design and construction work for new overhead lines following the February earthquake were achieved extremely quickly
- Orion's operations and engineering groups experienced huge workload increases following both earthquakes – the teamwork culture that Orion fosters assisted greatly in maintaining morale and restoration momentum
- much of the earthquake damage to electricity (and other) assets were a result of liquefaction and lateral spreading. The seismic strengthening generally, and successfully, addressed shaking hazards.
- while much electricity supply was lost as a result of cable damage, the extensive interconnections in Orion's 11kV and 400V network facilitated electricity restoration by providing routing options not available in radial (non-networked) distribution systems
- risk management is prominent in Orion's management practices. For example, Orion has adopted the '4 Rs' (Risk Reduction, Readiness, Response and Recovery) in its emergency management arrangements quite explicitly. Integration of emergency management with operational management functions in this way may be unique in New Zealand Lifeline circles
- looking ahead, a balance will need to be found between longer-term reliability and expenditure on security. It is unlikely that electricity supply reliability will recover to previously favourable levels without a significant ongoing commitment of resources to underground repairs.

A full copy of the report is available at http://www.oriongroup.co.nz/publications-and-disclosures.aspx

Lessons learned

As borne out by this independent review, preparation and planning meant Orion was able to respond well to the earthquakes. However, we still learnt some valuable lessons about risk management which we are implementing (for example moving away from basement substations) in order to make ourselves more resilient should our city suffer disaster again.

For instance, in the weeks following the February 2011 earthquakes, we were the first EDB in New Zealand to invest in a portable computer centre to house our operating and control systems. This mobile 'nerve centre' allows us to place the backup equipment at a different location from the main computer room to help mitigate risk.

This mobility allows us to operate from many locations throughout the city, if our main head office location were to ever again become uninhabitable.

In addition, during 2011 we implemented the final stage of our new network management system (PowerOn), which allows us to keep track of the real-time state of our electricity network. This technology significantly improves our ability to manage network emergencies and restore power faster when outages occur. The heart of the system is a computer-based model which holds information about every circuit breaker, transformer, line, cable and all the other equipment on our network. The system helps us better manage our assets, plan maintenance in smarter ways and minimise the potential for equipment overload.

Our preparation for, and response to, earthquakes and other natural hazards is subject to ongoing review, with a focus on where we can improve. We will continue with a prudent risk-based approach to our network planning and management.

What happens next?

Even though major emergency repairs are finished, there is still work ahead to build strength back into the electricity network. This is our recovery phase. Continuity of electricity supply is absolutely vital to the future of the city. The most important contribution Orion can make to boosting both business and community confidence in Christchurch is to keep the power on where it is needed, quickly respond if it goes out, and promptly provide accurate information during major power cuts.

In this respect two city and regional strategy documents have been recently published which are key to the recovery of Christchurch:

- the CERA Recovery Strategy for Greater Christchurch, published May 2012
- CERA's Christchurch Central Recovery Plan, published July 2012.

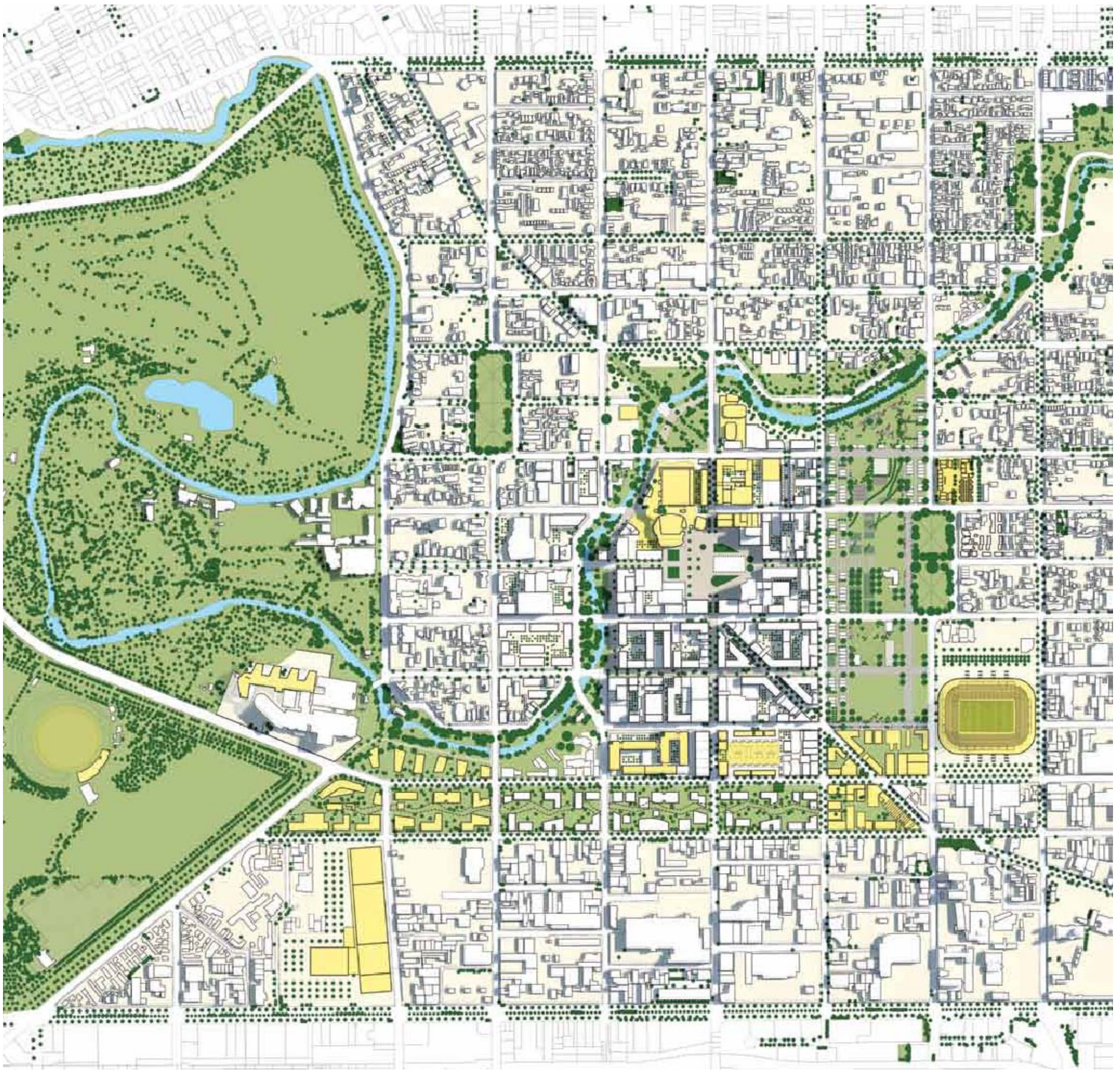
Both of the above documents have been approved by the Minister for the Canterbury Earthquake Recovery. These are critical to restoring confidence in the city. The proposed central city blueprint plan is illustrated overleaf.

Consistent with CERA's strategy documents, Orion's principal roles during the recovery phase will continue to be to:

- protect and enhance our electricity network, restore network resiliency and support future growth
- co-operate with property developers, local authorities and other agencies to ensure timely provision of network services
- make it easy for consumers to connect to our network
- support growth and the provision of on-site and distributed electricity generation such as solar power and wind generation where this is economically justifiable.

We consider we have a critical role in assisting to restore confidence in the city.

Proposed central city blueprint plan



3.3 Impact on Orion

As explained above, the Canterbury earthquakes have caused considerable damage to our network, particularly in the eastern suburbs of Christchurch. Our network resilience and reliability has reduced following the earthquakes and we are working hard to restore the network to its pre earthquake performance. Our electricity distribution network is fundamental to Canterbury's economic and social well being and we need to accommodate Christchurch's rebuild which includes redevelopment of the central business district and the creation of new residential and business subdivisions.

Accordingly we are no longer operating in a business as usual environment and it will be some time before this can be achieved. This CPP proposal is a direct response to these circumstances.

3.3.1 Impact on revenue, opex and capex

The following table summarises the material incremental financial impacts (compared to budget) which have arisen as a result of the earthquake, to 31 March 2012, as disclosed in our FY12 financial statements. We note that as time goes by it is becoming more difficult to distinguish between earthquake and non earthquake impacts.

Financial impact of earthquakes		
($m pre-tax)	**FY11**	**FY12**
Increased operating expenses	12.6	14.0
Increased major capex	-	10.6
Reduced electricity delivery revenue	3.1	20.6
Insurance settlement revenue	-	22.3

Opex

Our operating costs increased in direct response to the earthquakes as we undertook substantial emergency works and repairs. These were offset to some extent by deferral of planned opex. We estimate $6.1m of planned opex was not completed in FY12 due to prioritisation of earthquake recovery activities. We note that there is a need to prioritise the earthquake response in order to manage the large number of tasks to be completed and accommodate the needs of consumers and other external agencies such as CERA.

Capex

We also incurred extraordinary capital costs once we started to repair and rebuild the network. The major projects completed in FY12 comprised the temporary 66kV overhead lines ($1.6m), the new New Brighton substation ($8m) and investment in standby diesel generators ($1m). No major capex projects were cancelled in the year, although a number were postponed until future years. Major earthquake related capital work is ongoing and Sections 8 and 9 of this proposal describe our current and planned projects in this respect. We note that we must invest appropriately in our network as the long term consequences of under-investment are severe for consumers.

Delivery revenue

As many of our consumers suffered substantial damage to their homes and businesses, electricity consumption declined and many connections (particularly in the CBD) were either cordoned off or abandoned. This impact was most pronounced following the February 2011 earthquake. This meant our electricity delivery revenue fell as a result of the immediate loss of supply following each event, and the ongoing disruption to our consumers, even once supply was restored to those who were able to receive it. Accordingly, electricity volumes across our entire network were about 10% below budget for FY12. Our projections of the future electricity demand on our network are set out in Sections 7.2 and 9.7 of this proposal. We note that we do not have perfect information about the likely future development of the city. We are doing everything possible to gather the information we need to contribute to city planning and determine our own investment requirements.

Insurance settlements

Orion's network was insured to the fullest extent that was economically viable. The group has two key insurance policies relevant to the recent earthquakes as follows:

- material damage – this is a full replacement policy and covers the group's corporate properties and most of its key substations (it excludes those substations sited in consumers’ premises). Network overhead lines and underground cables have not been insured as it has not been economic to do so

- business interruption – lost revenues and additional costs are claimable if they arise ‘…as a consequence of…’ damage to the group’s insured assets and occur within the first eighteen months following the event.

We note that our loss of revenue claims are expected to be minor because most of our lost revenues are as a result of depopulation effects and damage to our cables and lines.

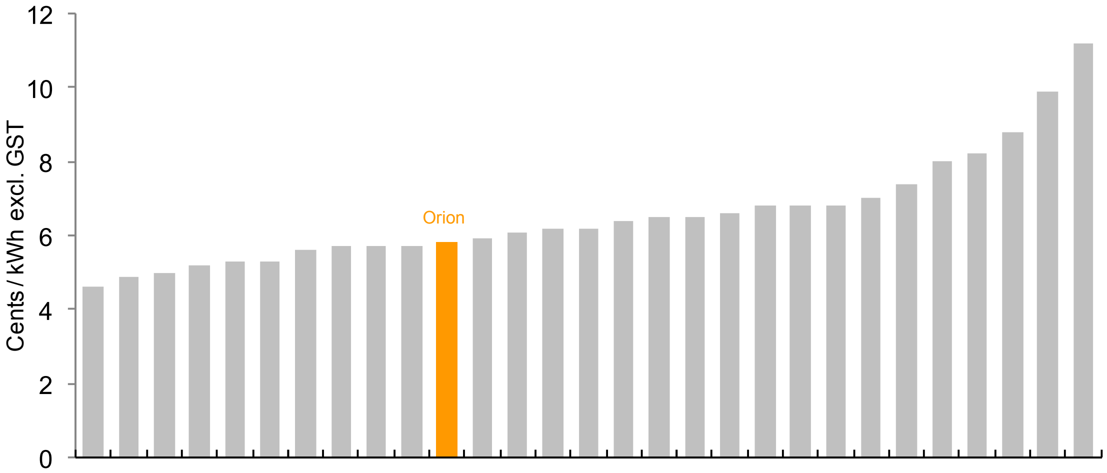
Orion’s main head office buildings suffered significant damage. We have reached agreement to cash settle with our insurers on three of our significant buildings on the head office site, and their unrecoverable contents, for the impacts of the 22 February 2011 and 13 June earthquakes. Further settlements are expected in the current year and our revenue forecasts include allowances to this effect. This information is set out in Section 7.3.7 of this proposal.

However, we face significant unanticipated and uninsurable costs and losses arising from the catastrophic and unprecedented events. It has not been and continues to not be economically practical to fully insure Orion’s overhead lines and underground cables for catastrophic events. These assets comprise approximately 65% of the replacement value of our network. It has been economic to ensure our key substation assets, which we have consistently done and will continue to do. Further information regarding Orion’s approach to insurance is set out in Sections 7.1.3 and 9.23.7 of this proposal.

As our current prices were set before the February 2011 and subsequent earthquakes, we need to consider how we pay for the unanticipated and uninsurable costs that we have incurred as a result of these catastrophic events.

We note that we have increased our line charges at less than the rate of inflation over the last decade, and we did not increase them at all this year, i.e. at 1 April 2012. Our line charges are relatively low when compared to other networks as shown in the table below.

Orion's price relative to other New Zealand electricity distributors (FY10 average kWh price excl. GST)



In addition, the detrimental financial impacts on our business are ongoing, yet our network is as needed today, as it was before the earthquakes in order to support the rebuild and maintain economic and social activity. Our forward looking expenditure plan (which is set out in detail in Sections 8 and 9 of this proposal) includes significant remedial expenditure necessary to restore our network to its pre-earthquake condition. In addition, we must accommodate the changes to our region which have been brought about by the earthquakes, as people and businesses relocate. It has therefore been necessary for us to review our asset management plans, revise our capex and opex projections and accordingly review how we will set our prices over the near to medium term.

Impact on long term plans

It is difficult to quantify the earthquake impact on our longer term expenditure plans, because these plans are updated annually to reflect new information and further investigation into likely network constraints and solutions.

A direct comparison between our CPP forecasts and our 2010 AMP (published in March 2010, prior to the first major earthquake in September 2010) demonstrates, that for the FY13 to FY19 period we are now forecasting:

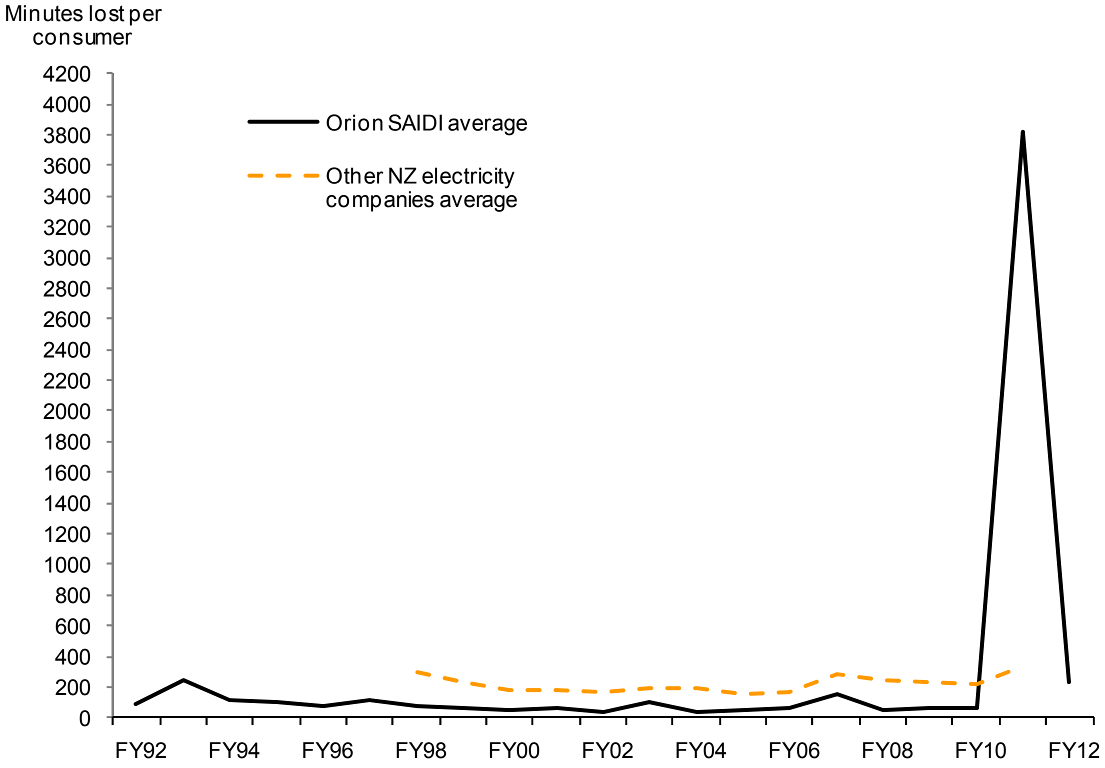
- $156m more in network capex than we were in 2010
- $22m less in network maintenance than we were in 2010.

These values are expressed in FY13 real terms and exclude the impact of increases in non-network expenditure, such as our new head office site and building. As we have not in the past prepared long term forecasts for our non network capex and opex it is not possible to present a similar comparison for non network expenditure. We note that we will include long term forecasts for non network expenditure in our AMP to be published in March 2013.

3.3.2 Impact on performance

The damage experienced to the network has compromised our network resilience and reliability, and we are working hard to restore it to pre-earthquake levels as we recover over the next few years. We are reviewing our fundamental network architecture and other assumptions which will determine our network resilience and reliability performance. Historically our network reliability performance has consistently been in the top (best) quartile of New Zealand EDBs, as expected for urban/metropolitan networks. This is illustrated in the information provided in Section 6.2.1 of this proposal, and the diagram below.

Orion's position relative to the SAIDI average of other NZ electricity network companies



Consumers have experienced a considerably less stable network since the earthquakes, as a result of the outages experienced in the days after the earthquakes and the ongoing network failures since. The massive impacts of the earthquakes on our reliability can be seen in the graph below.

In FY12 and the months since, our reliability remains below where it was pre-earthquakes. As explained in detail in Section 6 of this proposal, despite our best endeavours, we do not expect that our network reliability will return to pre-earthquake levels for the foreseeable future although we do expect it to improve within that time. Specifically, in the near to medium term:

- we are carrying out a program of cable testing that is estimated to take in excess of five years to complete
- it will take a number of years to replace the temporary overhead 66kV lines in the urban area and to restore our necessary level of security to the Rawhiti and Dallington zone substations
- the significant repair and rebuilding of other infrastructure (roads, water and waste water services) exposes our assets to a higher level of risk of damage
- we anticipate we will require more planned outages to accommodate not only our own repairs, but the other construction activity to be undertaken in and around our assets.

As our network has been subject to catastrophic impacts and as it will take some time to restore our network resilience and performance, it is necessary for us to review our quality standards and prices for the near to medium term.

3.4 Order in Council

During 2011, Orion sought an OIC under the Canterbury Earthquake Recovery Act to address our electricity distribution pricing. We anticipated that an OIC would have enabled us to recover some or our entire earthquake related costs and lower revenues in a timely way and to spread that financial recovery over several years.

However, in February 2012 it was decided that applying for a CPP in accordance with the Commerce Act was a more appropriate approach. We note that at the time we were applying for an OIC there were no provisions available to us to apply for a CPP in response to a catastrophic event – the relevant provisions were not gazetted until February 2012.

Accordingly, we are now required to make a CPP application to address our abnormal circumstances. This is required to provide us with new regulatory quality standards and a new price path.

We were disappointed with this outcome. We believe that an OIC would have provided a superior solution for our consumers because we would have been able to provide more certainty earlier, and at lower cost.

The CPP process is extremely resource intensive and we have had to divert resources from developing and implementing our earthquake recovery programme, to preparing the material which we are required to include in this CPP proposal. This has placed additional burdens on our staff during a time of unprecedented pressure and uncertainty for them. Many of our staff have incurred personal losses as a result of the earthquakes, and as has been widely reported, reparation for these losses is taking significant time to resolve.

3.5 Default price-quality path

Orion is currently subject to price limits and minimum quality standards which are set by the Commission once every five years under a DPP Determination. Prices for electricity distribution services are currently able to be adjusted annually in line with CPI. The reliability standards which we must meet are constant for a period of five years, however in order to accommodate year on year variation in reliability performance, we are permitted to exceed these standards no more than once every three years. This recognises that factors such as external events and equipment failure influence the number and duration of our network outages. External events include storms or other parties working around our cables and lines which may inadvertently damage our equipment.

The DPP can no longer fully accommodate Orion’s circumstances given the significant impacts of the earthquakes on our network and our consumers. The current DPP price path and quality standards which apply to Orion were deemed to be reasonable in 2010, and for the next five years, based on what was known at that time. However, given the catastrophic nature of the earthquakes, that is now not the case.

Our network expenditure has increased as a result of the earthquakes. This reflects the costs of our immediate response in getting power back on to everyone as quickly as possible. It also reflects the ongoing costs associated with repairing our damaged network and offices and rebuilding the resilience in our network required to mitigate the impacts of potential future events such as storms, floods or earthquakes.

Further, as stated above, our revenue has fallen because of the extensive damage to the homes and businesses of our consumers, particularly in Christchurch city and the eastern suburbs of Christchurch. While Orion's network was insured to the fullest extent that was economically viable, and significant insurance proceeds have been obtained to assist to fund our repairs, it is not possible to fully insure our lines and cables for the impact of catastrophic events. We note that we had invested prudently in network resilience and diversity, which minimised the impacts of the earthquakes considerably. These factors mean we are unable to meet our costs, including a normal rate of return on our investment.

Finally we are currently not able to meet the DPP quality standards which were set for us in 2010, and apply to us until 31 March 2015. The quality standards impose minimum network outage duration (SAIDI) and outage frequency (SAIFI) limits on us. However, because our network was damaged so extensively during the earthquakes, it is no longer as reliable as it once was. In addition because there is so much rebuild activity expected over the next few years we are going to need to accommodate that by allowing for planned outages to ensure work can be completed safely in and around our network. We expect further disruption also due to unplanned outages arising from third parties who will be working around our assets.

Accordingly Orion must apply for a CPP in order to address these impacts on our network performance.

The DPP Determination anticipates that following a catastrophic event, new price paths and quality standards may need to be set for an EDB, via a CPP. A catastrophic event is defined at clause 5.6.1 of the IMs as follows:

> Catastrophic event means an event-
>
> (a) beyond the reasonable control of the EDB;
>
> (b) in relation to which expenditure-
>
> > (i) was neither sought in a CPP proposal; nor
> >
> > (ii) is explicitly or implicitly provided for in the DPP or CPP, as the case may be;
>
> (c) that could not have been reasonably foreseen at the time the CPP or DPP was determined; and
>
> (d) in respect of which-
>
> > (i) action required to rectify its adverse consequences cannot be delayed until a future regulatory period without quality standards being breached;
> >
> > (ii) remediation requires either or both of capital expenditure or operating expenditure during the regulatory period;

(iii) the full remediation costs are not provided for in the DPP or CPP; and

(iv) in respect of an EDB subject to a CPP, the cost of remediation net of any insurance or compensatory entitlements would have an impact on the price path over the disclosure years of the CPP remaining on and after the first date at which a remediation cost is proposed to be or has been incurred, by an amount at least equivalent to 1% of the aggregated allowable notional revenue for the disclosure years of the CPP in which the cost was or will be incurred.

The circumstances pertaining to the Canterbury earthquakes which have affected our business meet the definition of a catastrophic event because:

- they were beyond our control (5.6.1(a))
- resulting expenditure was not explicitly or implicitly provided for in the DPP Determination (5.6.1(b)(ii))
- they could not have been reasonably foreseen at the time the DPP was set (5.6.1(c))
- action to rectify the consequences cannot be delayed until the next DPP regulatory period without breaching the DPP quality standards (5.6.1(d)(i))
- remediation requires both capital and operating expenditure during the regulatory period (5.6.1(d)(ii))
- full remediation costs are not provided for in the DPP (5.6.1(d)(iii)).

The DPP Determination provides for a 24 month window following a catastrophic event in which an application can be made to the Commission for a CPP. This window expires for us on 22 February 2013.

3.6 Decision to apply for a CPP

Our decision to apply for a CPP has not been taken lightly. As the CPP process requires a large amount of information to be presented to the Commission, which is to be independently reviewed and consulted upon, the CPP process is necessarily quite long. It has taken us about 12 months to prepare our proposal and have it independently reviewed and audited. It will be more than another 12 months before the CPP comes into effect, on 1 April 2014.

We do have reservations about the appropriateness of this process in responding to a catastrophic event. In our view the CPP requirements are not tailored to the consequences of a catastrophic event. We are concerned at the amount of information and evidence we must provide which is not of direct consequence to the earthquakes and the earthquake response. This seems to be an unnecessary cost to us, at a time of intense demand for our resources.

However, we recognise that it is important to have an independent body, the Commission, review our proposed expenditure, price path and network performance standards which reflect the consequences of the earthquakes on our business.

We support using the rules set out in the Commerce Act for this purpose, and the role of the Commission in making a decision on how we should set our prices and quality standards for the next five years. We believe that the proposed price path and quality standards which we have put forward in this proposal are fair, realistically achievable and consistent with the needs of our consumers for a safe and reliable electricity network in Canterbury. We are seeking independent confirmation that our proposal is reasonable and, as required by the Commerce Act, in the long term interests of our consumers.

We must invest in our network to provide our consumers with the electricity supply service they need. The Commission's review of this proposal aims to ensure that our past and proposed expenditure is efficient, prudent and necessary in order to meet the long term interests of our consumers.

One of the important features of our CPP proposal is the application for claw-back which is intended to retrospectively account for the immediate consequences of the catastrophic events which have triggered our CPP application. The Commerce Act permits claw-back for CPP applications made under these circumstances. As we have not been able to fully recover our abnormal costs and our abnormal losses which have occurred since 4 September 2010, we have proposed an approach to claw-back which is spread over a number of years to ensure that the price impacts on our consumers are mitigated as much as possible. The methods and assumptions we have used to assess the value of claw-back are set out in Section 7.2 of this proposal. We have used the Commission's IMs for this purpose because we believe these are consistent with determining fair prices which are in the long term interests of consumers.

3.7 Orion's approach to the CPP

The CPP IMs prescribe the information that must be included in our proposal, the independent review, audit and certification processes we must undertake before it is submitted to the Commission for assessment; and the requirement to notify our consumers about our plans and invite their participation in consultation on the proposal. We have complied with these requirements. In Appendix 4 we include a table which includes references to relevant sections of this proposal which demonstrate our compliance with all of the information requirements for a CPP proposal.

This proposal is accompanied by additional information which together comprise our CPP application, namely:

- a description of our consumer consultation
- a verifier's report
- an audit report
- our Directors' certification.

Meeting the information requirements of the CPP IM

We understand our CPP application will be the first application made under the Commerce Act Part 4 provisions for CPPs, and the associated CPP IM. Accordingly we will be the first regulated supplier to be subject to the CPP rules, methods and processes. During our CPP proposal preparation we have discovered some elements of the CPP IM which are difficult to comply with. We believe this is partly because they have not been tested in practice before, and also other parts of the regulatory regime, which are relevant to the CPP IM, such as revised ID regulation, are still being implemented. Where possible we have discussed our concerns with the Commission before finalising this proposal.

In Appendix 5 we include a full list of the areas where we have had to make judgements about how we have met the information requirements contained in the CPP IM. We have discussed these with the Commission, and accordingly do not believe these judgements constitute IM variations, as provided for under section 53V(c) of the Commerce Act.

We note that during the 22 February 2011 and subsequent 13 June 2011 earthquakes our head office building sustained major, irreparable damage. We were forced to evacuate our main office building on 22 February and have had only limited access to it since to retrieve our business records. We have been operating from temporary accommodation and support buildings located on our head office site since that date, and are shortly to move to a new office building out of the city centre. Our current location will no longer be available to us as it is to form part of the ‘frame’ to the redesigned Christchurch CBD, consistent with CERA’s Christchurch Central Recovery Plan.

We lost some functionality in our financial systems during the earthquakes, and while we have been able to back up the majority of our historical financial records we have lost the ability to interrogate some information for periods prior to 1 April 2009. This means it is not possible for us to retrospectively apply all of the new CPP IM information requirements prior to 1 April 2009. The CPP IM requirements were determined in December 2010, and as Orion had not anticipated having to apply for a CPP, our information has not been collated in a way which mirrors all of the CPP requirements. We have reconfigured our information from 1 April 2009 to match the CPP information requirements as best as we are able to, but there is some disaggregated data missing for FY08 and FY09. Aggregated data is however available for those periods.

Information disclosures

The CPP IM assumes that EDBs which apply for a CPP will have made annual disclosures to the Commission consistent with Part 2 of the IMs, and relevant ID Determinations which incorporate those Part 2 methods. Orion has made no such disclosures, because the ID Determinations were not gazetted until 1 October 2012, and the first disclosures are to be made for the FY13 regulatory period later this year.

With the assistance of the Commission we have addressed this issue by completing regulatory returns (which were initiated by the Commission via section 53ZD Notices) which restate our previous regulatory position for FY10 to be consistent with the Part 2 IMs. These provide the starting position from which information which complies with the CPP IM can be derived. Our responses to the section 53ZD Notices have been audited and certified consistent with the Commission’s requirements.

A further linkage between ID and the CPP IMs is Orion's AMP which is published in accordance with Part 4 information disclosure regulation. Our latest AMP was published in March 2012 for the planning period commencing 1 April 2012, consistent with the Electricity (Information Disclosure) Requirements 2008. Since that date, we have made considerable progress with reviewing our future plans for the network. This has been brought about by the need to undertake unprecedented investment in our network due to:

- earthquake damage to our assets
- changes in load due to post-earthquake reconstruction and relocation
- projected load growth in the western part of our network, independent of earthquake effects.

Accordingly, our CPP proposal puts forwards our most up to date plans for our network which reflect the considerable planning undertaken since the last AMP was published. While much of the network information, and planning systems and processes which are documented in our current AMP remain largely unchanged, our core forecasts and expenditure plans have been revised and updated. Thus our forthcoming AMP, to be published in March 2013, will include:

- updated forecasts of demand and expenditure which are consistent with those included in this CPP proposal
- amendments to comply with the new AMP disclosure requirements as set out in the October 2012 ID Determination.

This AMP will cover the 10 year planning period commencing 1 April 2013 and ending on 31 March 2023. It will therefore extend beyond the CPP regulatory period, which ends on 31 March 2019.

Forecasting uncertainty

In applying for a CPP we are required to put forward detailed forecasts for a seven year period (ie: a two year assessment period and a five year regulatory period). Once a CPP proposal is submitted, and the Commission has completed its assessment, we are unable to modify our forecasts. This differs to the AMP planning process where we update our forecasts annually on the basis of further information and analysis.

Under normal circumstances, we would expect to be able to adequately manage forecasting uncertainty within a regulatory period. Indeed the five year DPP price path and quality standards require us to do so. However, we are not currently operating under normal circumstances and new information is constantly emerging about the condition of our assets, the future needs of our consumers, our input costs and the development of the Canterbury region.

We have collated all of the information we can reasonably acquire, and used our expertise and judgement to prepare the forecasts on which this CPP proposal is based. We anticipate however that information will emerge subsequent to submitting this proposal which, if incorporated into our thinking, would cause us to modify our views. This is the nature of the process however, and as we are constrained by the two-year catastrophic event application window, we have proceeded with this application in good faith. We therefore encourage the Commission to consider the challenges which face us in committing to a long term plan during a period of unprecedented uncertainty.

We note we have included no provisions in our CPP proposal for potential future catastrophic events. Should Orion experience high impact events during its CPP regulatory period, which are unable to be accommodated in the CPP price path and quality standards, we will seek to re-open the CPP Determination in accordance with catastrophic event provisions of Part 5, Subpart 6 of the IMs.

We also note that the time constraints and our focus on rebuilding our network have resulted in a CPP proposal which concentrates primarily on our consumer's needs, our associated investment requirements, our network performance, and the appropriate price and quality standards which are consistent with those needs. Accordingly we have not included in our proposal any tailored incentive mechanisms. This is discussed further in Section 9.24. While Orion might consider these when operating in more normal circumstances, we do not believe they are appropriate for us at this time given our primary focus is on returning to a business as usual position.

3.8 Key evidence supporting the decision to apply

IM 5.4.2(b)

The key evidence supporting our decision to apply for a CPP can be summarised as follows:

- Canterbury has been hit by catastrophic earthquakes over a prolonged period which commenced on 4 September 2010. Evidence and explanations demonstrating the impact of those earthquakes on Orion and the wider Canterbury community is set out in the following sections of this proposal:
    - Section 3.2
    - Section 3.3
    - Section 6.2.2
- as a result, Orion's revenues have fallen and costs have increased. These impacts are explained in the following sections of the proposal:
    - Section 3.3.1
    - Section 7.1
- Orion's network resilience and reliability has been impaired and we are unable to meet our DPP quality standards. This is explained in the following sections of the proposal:
    - Section 3.3.2
    - Section 6.3
- accordingly we must now invest in our network to restore its resiliency and regain reliability standards which meet the needs of our consumers. This is explained in the following sections of our proposal.
    - Section 6.4
    - Section 8.3
    - Section 9.11
- our prices are currently regulated under the DPP, and these are insufficient for us to recover our costs and earn a fair return on our assets. While we had prudently insured our assets to the extent economically viable, it is not possible to fully insure lines and cables and we therefore must recover our costs on an ex-post basis from

consumers. The DPP price path does not include allowances for the impact of catastrophic events. This is explained in the following sections of this proposal:

- Section 3.5
- Section 3.6
- Section 7.1

This CPP proposal therefore seeks a new price path and new quality standards which better meet our post-earthquake circumstances, than those which currently apply to us under the DPP.

3.9 Appendices and supporting documents

Section 3 – Appendices	
Appendix	**Title**
4	Satisfaction of CPP IM information requirements
5	Modifications to Schedule E templates

Section 3 – Supporting Documentation
Title
An independent study commissioned by the Earthquake Commission - The Value of Lifeline Seismic Risk Mitigation
Kestrel Group Independent Report – Resilience Lessons: Orion's 2010 and 2011 Earthquake Experience
CERA – Recovery Strategy for Greater Christchurch
CERA – Christchurch Central Recovery Plan

4 Priority of proposal

4 Priority of proposal

IM 5.4.1 and 5.4.3

4.1 Information requirements

When making a CPP application under normal circumstances, it is intended that a CPP proposal will include information regarding the priority of the proposal. This is to allow the Commission to assess the urgency of the proposal in order for it to prioritise its assessment, where more than one application is made at the same time.

Our CPP proposal does not include any information regarding the priority of the proposal, because our application has been made in response to the earthquakes. Where a catastrophic event such as a major earthquake has occurred, the Commission is able to prioritise it ahead of regular applications, i.e.: those not made in response to a catastrophic event.

The first major earthquake occurred in Christchurch on 4 September 2010. The earthquake which caused the most damage and subsequently became the trigger event for our CPP application occurred on 22 February 2011.

In March 2012, the Commission determined that the window for applying for a CPP in response to a catastrophic event would be 24 months. This is set out in the Commission's DPP Determination for EDBs dated 22 March 2012.

Accordingly, as our CPP application has been made within the 24 month window provided for in the DPP Determination, we have not included any information regarding the priority of our proposal in accordance with clauses 5.4.1 and 5.4.3 of the CPP IM.

5 Duration of regulatory period

5 Duration of regulatory period

IM 5.4.4

5.1 Regulatory period

It is proposed that Orion's CPP regulatory period applies for a period of five years commencing 1 April 2014. Accordingly the CPP will cease to apply on 31 March 2019.

Orion has considered and determined that there is no reason a shorter CPP period should apply, noting that CPP periods of three or four years can be considered as alternatives. There is no provision in the regulatory rules for a CPP regulatory period of greater than five years.

Given the magnitude of the earthquakes and the immediate and evolving impact on Orion, it is reasonable to provide for the maximum CPP regulatory period. This is necessary to accommodate the special circumstances which our network has experienced since September 2010 and now faces for the foreseeable future.

We are very mindful of the impact of price increases on consumers. We have approached our CPP proposal in a conservative manner in this respect, and we believe that the maximum allowable regulatory period is consistent with this philosophy. The maximum period allows us to smooth the pricing impacts as much as possible and provide as much certainty for our consumers as we are able to give them within the constraints of the regulatory regime. In addition it minimises our costs by ensuring we are only engaging in these regulatory processes when we absolutely must. More information on this approach is included in Section 7.1 and 7.2 of this proposal.

At the end of the CPP period we have the option of applying for a further CPP or reverting back to the DPP. We plan to make that choice towards the end of our CPP period.

5.2 Claw-back period

As our CPP application is in response to a catastrophic event, we are able to also look backwards to the date of those events.

A CPP application made in response to a catastrophic event may include the value of claw-back in its price path proposal. In this instance, claw-back reflects the shortfall in revenues required to recover our costs, which occurred following the catastrophic event(s), up to the date that the CPP comes into effect.

As the earthquake activity commenced on 4 September 2010, we have considered the impact of the earthquake events which have occurred from that date up to the commencement of the CPP period, ie: up to 1 April 2014. This is our proposed claw-back period.

We are also proposing that the value of our catastrophic event claw-back is recovered over a considerably longer period than the five year CPP regulatory period. This is consistent with the legislative intent to smooth price impacts on consumers while ensuring we are able to recover our fair costs and earn a normal return, which are also consistent with the long term interests of consumers.

The method we have used to calculate the claw-back amount is described in Section 7.1.2 of this proposal. Our proposed approach for recovering the claw-back amount is described in Section 7.2.2 of this proposal.

5.3 Claw-back recovery

Our proposal is to spread the catastrophic event claw-back recovery over 10 years. This comprises at least two regulatory periods – the initial five year CPP regulatory period followed by one or more CPP or DPP regulatory periods. Our key driver for spreading this recovery over more than one period is to minimise price shocks to our consumers. At the same time, it is essential that the catastrophic event claw-back is ultimately recovered in order to maintain long term incentives to invest in the Orion network, and all electricity distribution networks regulated under Part 4 of the Commerce Act.

The IM does not specifically refer to spreading claw-back of catastrophic event costs (under section 53V(2)(b) of the Act) over more than one regulatory period. However, we believe this option remains open to the Commission under clause 5.3.4(1) of the IMs, which refers to the price path for a CPP including '…any value of claw-back for the CPP regulatory period.' This does not limit recovery of the claw-back amount to a single CPP regulatory period. It refers to inclusion of the portion of the full amount that is to be recovered during that particular CPP regulatory period.

Our concern is that the IMs do not clearly specify how unrecovered claw-back arising under clause 5.3.4 may be recovered in subsequent regulatory periods. In order to gain certainty for our investment planning and our consumers about subsequent claw-back recovery timeframes we seek a clear commitment from the Commission within our CPP Determination to the 10 year recovery period and catastrophic event claw-back amount.

We have given considerable thought as to how the Commission can demonstrate this commitment in its CPP Determination. We propose the following approach.

For the initial CPP regulatory period, we seek express confirmation of:

i. the total quantum of the amount to be clawed back over time, in present value terms (as at 1 April 2014)
ii. the total time frame (10 years) over which the claw-back amount referred to in (i) is intended to be recovered
iii. the total quantum of the amount to be clawed back within the CPP regulatory period, in present value terms (as at 1 April 2014)
iv. the total quantum of the amount to be clawed back in the five years immediately following the CPP regulatory period, in present value terms (as at 1 April 2014)

v. the value of claw-back that will be recovered for each year during the CPP regulatory period, in nominal terms (our proposed recovery during the CPP regulatory period is set out in Section 7.2.2)
vi. the method for determining the value of claw-back, in nominal terms, to be recovered for each year of the five year period immediately following the CPP regulatory period (our proposed method is set out in Section 7.2.2).

At the end of the CPP regulatory period, we will revert to the DPP (or may, if necessary, apply for a further CPP). The DPP IMs can be interpreted so as to not allow catastrophic event claw-back, and the CPP IM is equally ambiguous as to recovery of remaining claw-back amounts determined during an earlier regulatory period. Therefore, in order to provide us with the necessary level of certainty as to cost recovery over time, we need to address now how the DPP (or CPP) process will enable us to recover the remaining claw-back amount in a subsequent regulatory period

We believe that the two most workable alternatives for recovery of the remaining claw-back amount under the DPP Determination (or a subsequent CPP) are:

- Option A - amending the IMs by changing the definition of recoverable costs for example in clause 3.1.3(1) under a DPP (and a CPP) to include remaining catastrophic event claw-back, the quantum of which has already been determined under a CPP Determination in response to a catastrophic event. This would enable supplier-specific consideration of the total claw-back quantum by the Commission during the initial CPP process, and thus remove the current impediment identified by the Commission in the IM Reasons Paper for recovery of catastrophic event costs by way of claw-back under the DPP
- Option B - altering the price-path for Orion under section 53P(8) of the Act at the time at which we transition from the CPP to a DPP.

In the absence of a DPP IM that covers this issue, the most secure way forward is Option A. We seek a clear commitment from the Commission in its CPP determination and Reasons Paper in support of this option going forward. Either way, it is important that the mechanism the Commission prefers is clearly signalled in the CPP Determination.

If the Commission cannot provide us with at least this level of assurance as to subsequent recovery of the remaining claw-back amount, Orion seeks recovery of the full claw-back amount in this CPP Determination and a single regulatory period. We have included an alternative price path in Section 7 of our proposal which assumes the claw-back amount is recovered fully within the CPP regulatory period.

6 Quality standard variation

6 Quality standard variation

IM 5.4.5

6.1 Summary

We seek a quality standard variation for the CPP regulatory period. We are unable to meet our current DPP quality standards (which are expressed as limits) due to the impact of the earthquakes on our network. The Commission set our DPP quality standards prior to the earthquakes and so our standards do not reflect the impacts of the earthquakes.

Our proposed CPP System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) quality standards are set out in the table below.

Our proposed standards (limits) better reflect the realistically achievable performance of our network over the CPP period. Our proposals have been derived using a similar approach to that inherent in the DPP quality standards.

Our current DPP standards and our proposed standards for FY15 to FY19 are shown in the table below.

CPP regulatory period

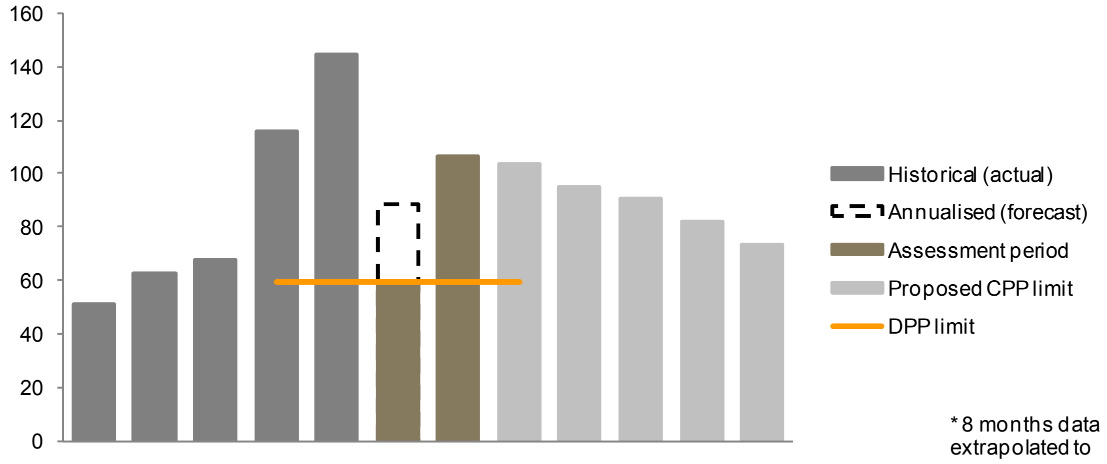
	FY15	FY16	FY17	FY18	FY19	Current DPP standards
µSAIDI	94.7	86.5	83.1	75.2	67.0	53.0
σSAIDI	9.0	8.2	7.9	7.2	6.4	6.7
SAIDI limit	103.8	94.7	91.0	82.4	73.4	59.7
µSAIFI	1.25	1.11	1.07	0.94	0.80	0.68
σSAIFI	0.11	0.09	0.09	0.08	0.07	0.10
SAIFI limit	1.36	1.21	1.16	1.02	0.87	0.78

Since FY11, our network reliability performance (SAIDI and SAIFI) has not met our current DPP standards.

The key feature of our proposed quality standard variation is that our quality limits increase in FY15 and then gradually reduce over the CPP regulatory period, reflecting our improving network resilience and reliability. This trend reflects our plan to re-establish the resilience of our network which was severely damaged by the earthquakes, consistent with our proposed expenditure plan and the needs of our consumers.

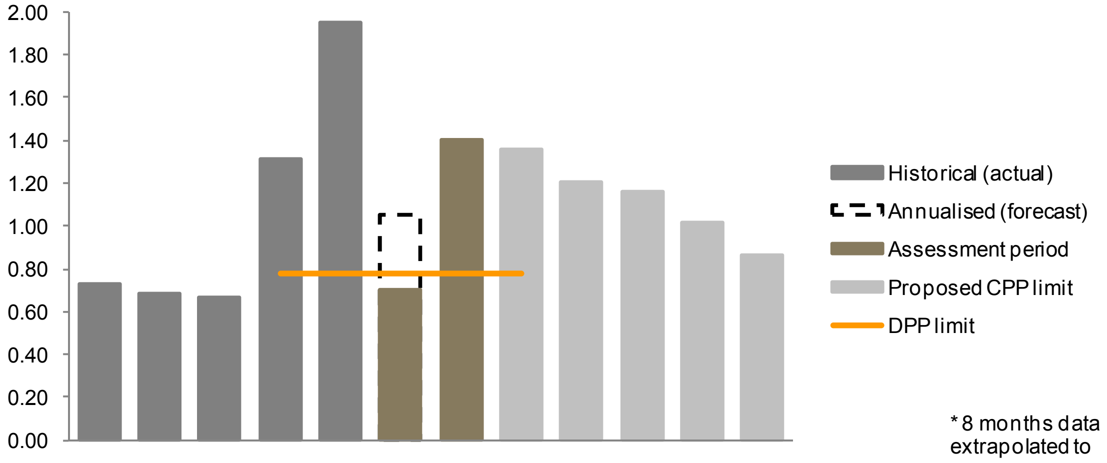
Our expenditure plan is described in Sections 8 and 9 of this proposal. Our consultation with consumers is described in our CPP application.

Historical normalised SAIDI (incl. earthquakes) with proposed CPP limit and DPP limit



*8 months data extrapolated to give annualised figure shown

Historical normalised SAIFI (incl. earthquakes) with proposed CPP limit and DPP limit



*8 months data extrapolated to give annualised figure shown

Due to the date of this application, we do not have full year SAIDI and SAIFI data for FY13. We have eight months of data which, annualised, generates SAIDI and SAIFI which is less than our proposed limits for FY15. We propose higher limits in FY15 than our forecast FY13 reliability performance because:

- the full extent of the damage to our network is still to emerge. It will take some years to identify and assess this damage, particularly for our underground cable network
- the Christchurch rebuild will result in increased planned and unplanned outages due to increased construction activities of third parties
- year on year variations are to be expected, particularly in relation to external events such as those caused by poor weather
- our urban sub transmission network is vulnerable and will continue to be until we are able to restore our network security standards.

Although FY14 falls outside the CPP regulatory period, we have derived an indicative limit for that year. This is necessary to establish our proposed limits for the CPP years which follow.

Our proposed CPP quality standards:

- are consistent with our proposed expenditure plan
- are realistically achievable
- importantly reflect expected significant improvements in our network reliability performance over the CPP period, consistent with the expectations of our consumers.

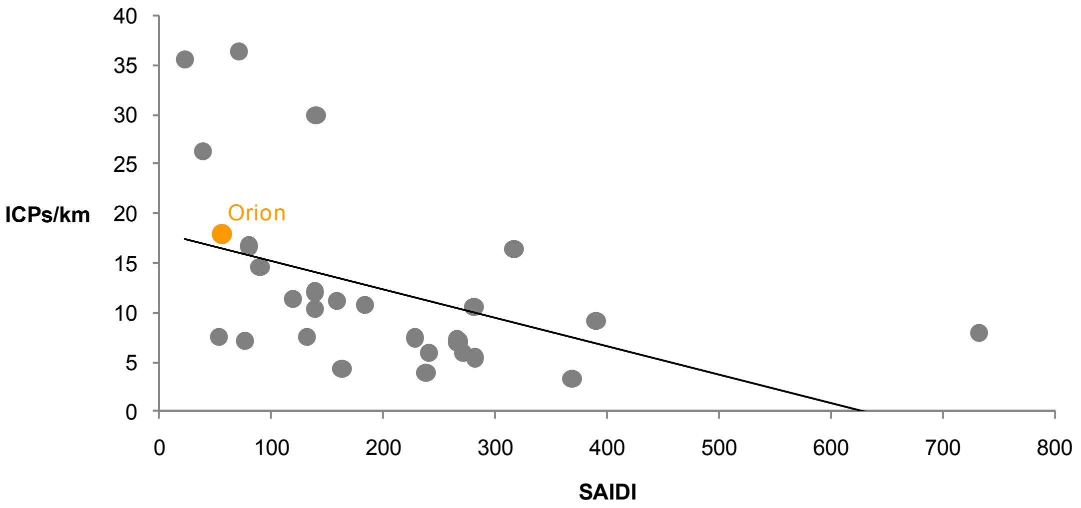
Our proposed limits use a similar approach that the Commission used to determine our current DPP limits. This approach attempts to accommodate expected year on year fluctuations in reliability performance.

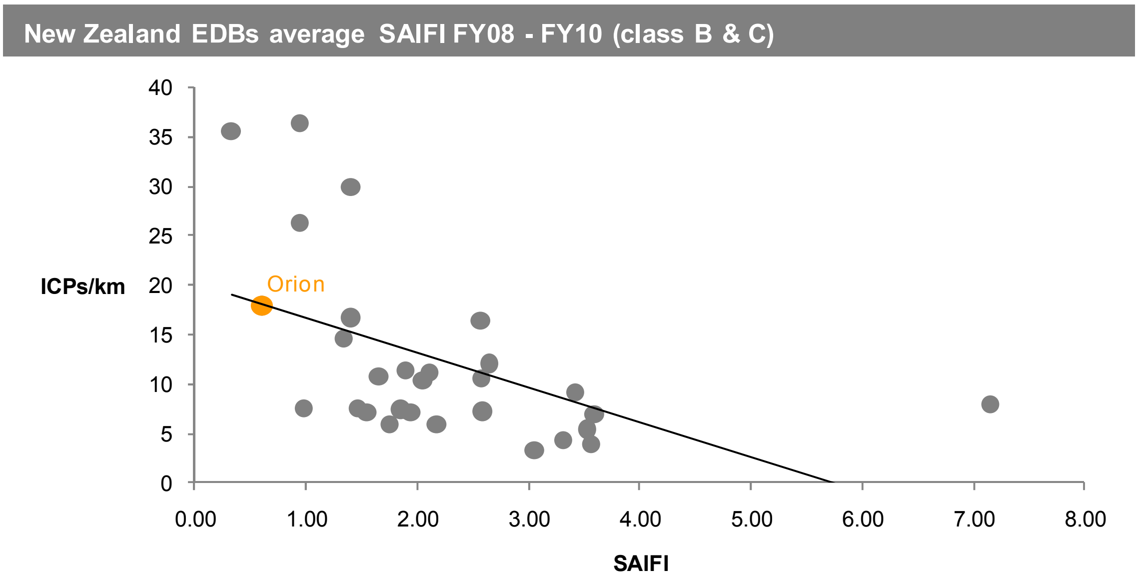
Our target is to return to near pre earthquake levels of network resilience and reliability by FY19. This is consistent with the regulatory regime which has applied to us since 2004 which established a ‘no material deterioration’ reliability standards for all EDBs subject to the Part 4A thresholds regime, and more recently the Part 4 price-quality regime.

Feedback sought from consumers in late 2012 supported our draft proposals to restore network resiliency and reliability.

While historically our network reliability performance has been better than many NZ EDBs, it falls within the expected range for urban networks with significant underground reticulation. The following charts show that our FY08 to FY10 performance was consistent with the expected trend for networks with relatively high connection density.

New Zealand EDBs average SAIDI FY08 - FY10 (class B & C)




New Zealand EDBs average SAIFI FY08 - FY10 (class B & C)

We believe that it is reasonable and in consumers' long term interests for us to restore network resilience and reliability to pre earthquake levels. This is consistent with consumer feedback. Our pre-earthquake performance is consistent with that expected for a relatively dense urban network.

The remainder of this section is structured as follows:

- Section 6.2 describes our historical network reliability performance
- Section 6.3 describes our current and expected reliability performance
- Section 6.4 describes our proposed CPP quality standard and the methodology, data and assumptions we have used
- Section 6.5 describes the counterfactual, calculated using the Commission's method to determine our current DPP quality standard. We also show how our proposed CPP quality standard method would have impacted on the DPP period if it had applied
- Section 6.6 describes the independent engineer's review of our proposed CPP quality standard. The independent engineer is LineTech Consulting
- Section 6.7 describes the consultation we undertook on our draft CPP quality standard proposals with our consumers in late 2012 and the feedback we received from consumers.

6.2 Reliability performance to date

IM 5.4.5(b)

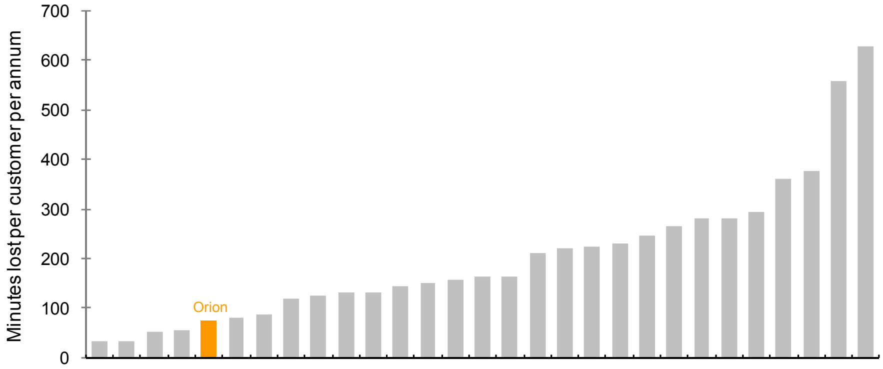
6.2.1 Historical performance

Prior to the earthquakes our network had been one of the most reliable in New Zealand. Our consumer consultation over many years told us that our consumers were happy with the service we provided, including the duration and frequency of network outages and the prices we charged for that service.

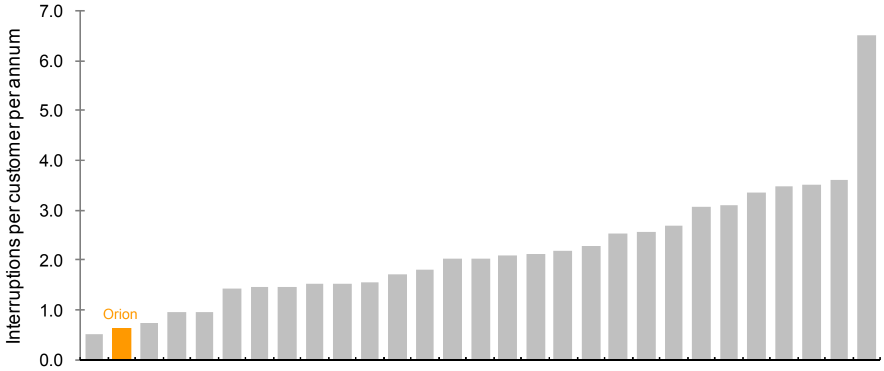
Using pre earthquake data for the five years to FY10, our electricity distribution network was on average (compared with other 28 electricity distribution networks in New Zealand) the:

- fifth best for SAIDI, the average number of minutes (duration) per annum that each consumer is without electricity
- second best for SAIFI, the average number of times (frequency) per annum that each consumer is without electricity
- eleventh lowest, in terms of line price (average price per kWh for FY10).

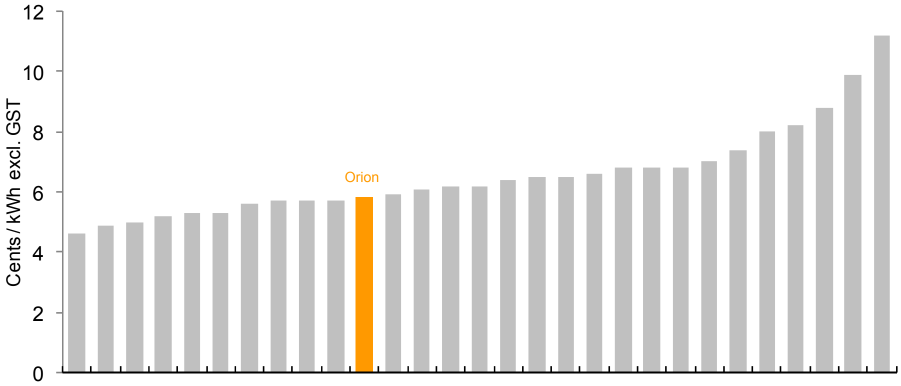
Orion's postion relative to other New Zealand electricity distributors, SAIDI (FY06 to FY10 average)



Orion's postion relative to other New Zealand electricity distributors, SAIFI (FY06 to FY10 average)



Orion's price relative to other New Zealand electricity distributors (FY10 average kWh price excl. GST)

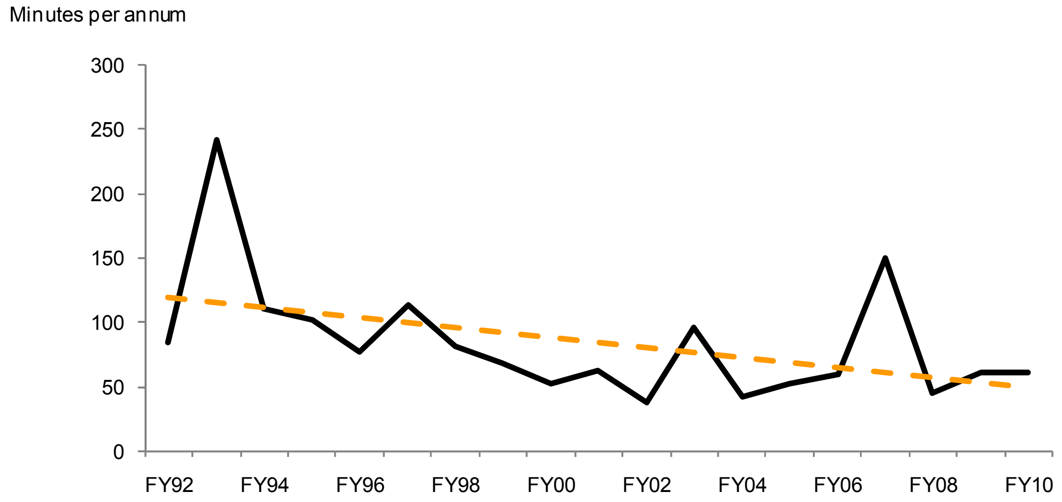


We serve urban and rural consumers. Our network has a mix of (mainly) rural overhead and (mainly) urban underground reticulation. Our network reliability performance is therefore subject to external weather events such as snow and high winds, particularly in our rural network.

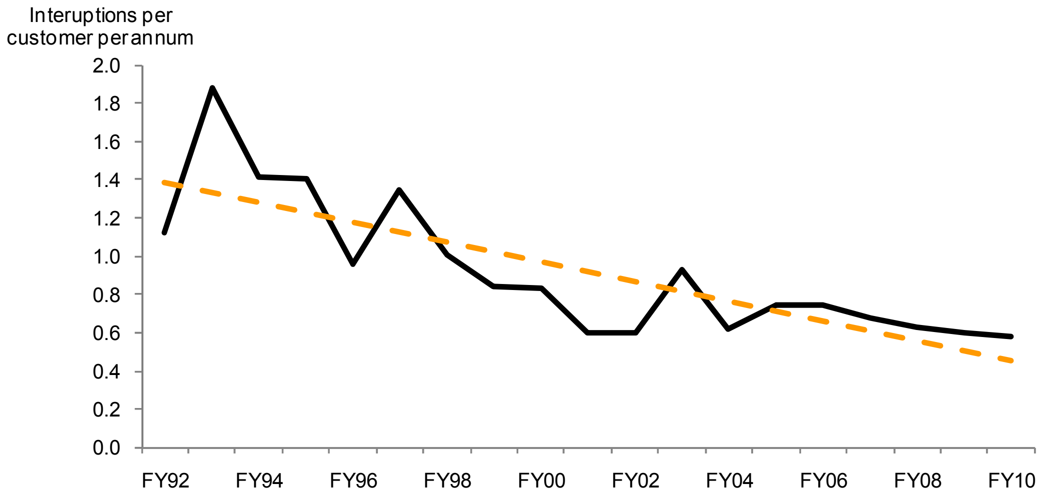
When considering performance from our consumers' perspective it is meaningful to look at the long term trends for SAIDI and SAIFI. The long term trend shows the impacts of extreme events which cause variations in electricity network reliability in any one year.

The following charts show the long term (improving) performance of our network and the impacts of extreme weather events with significant disruptions in FY93, FY97, FY03 and FY07 caused by severe snow storms in Canterbury.

Orion SAIDI performance from FY92 to FY10 with trend



Orion SAIFI performance from FY92 to FY10 with trend



We consult periodically with consumers over the level of service we provide. These consultations are described in Section 3 of our AMP, and more information is provided in Section 9.6 of this proposal.

Consumers expect a resilient and reliable supply of electricity with no reduction in service from current levels. In this respect 'current levels' refer to pre-earthquake service levels. Accordingly we have consistently endeavoured to provide a level of service which meets the expectations of our consumers in the long term as well as ensuring our safety, environmental, and legislative obligations are met.

Over the past decade we have improved the quality of supply for our consumers, while constraining our annual price movements to less than CPI, on average over the same period.

Although consumers have not explicitly requested improvements to our level of service, our network performance has improved over the past two decades (which is the period for which consistent and reliable data is available). This improving trend is a consequence of improvements we continually make in our business, such as our PowerOn network management system and our award winning wireless communications network which allows us to remotely switch our distribution network and protect key circuits without delay. It also reflects the incremental improvements in network performance achieved through investments required to meet system growth and our ongoing objective to improve the way we manage our assets over their life cycle.

To help meet consumer expectations, we analyse the performance of our network to determine just how 'reliable' it is. This information is then used to target areas for improvement. The measures we use and FY10 performance (pre earthquakes) is summarised below.

Pre-earthquake measures

Key service criteria	Quality measure (per annum)	Target level of service (FY10)	Level of service (FY10)	Outcome	New Zealand average (FY10)
Reliability	Faults/100km of circuit	< 11.0	6.7	Achieved	7.9
Reliability	SAIDI	< 63.0	61.0	Achieved	170.6
Reliability	SAIFI	< 0.76	0.58	Achieved	2.00
Reliability	CAIDI	< 83.0	106.0	Not achieved	85.9
Power quality	Non compliances	< 70.0	29.0	Achieved	Not available

All service level and reliability figures are based on our network only. They exclude those interruptions or complaints caused by failures on Transpower's transmission network.

In FY10 we were able to operate our network to targeted levels of service, with the exception of our consumer average outage duration (CAIDI) measure (reflecting higher than normal planned outages – which typically are of a longer duration).

A range of factors contributed to our strong reliability performance in FY10, continued network improvements throughout the year, comprehensive maintenance programmes, sound engineering practices and a year free of severe weather storms.

Our service level targets are based on an ‘average’ year of weather, not a year with severe weather. As a result, we are unlikely to meet our service level targets when severe external events occur. For example, when a major snow storm hit Canterbury in 2006, we were unable to meet our service level targets for FY07.

Network reliability is one of the service measures we use to assess our performance and ensure we meet the needs of our consumers. Section 9.6 sets out a full explanation of our other service measures, target service levels and performance.

6.2.2 Earthquake impacts

On 4 September 2010 Canterbury was hit by ongoing earthquakes that began with the 7.1 magnitude earthquake near Darfield. Since that time more than 12,000 aftershocks of varying magnitude have occurred in Canterbury. The most notable subsequent earthquakes have been the 4.9 magnitude earthquake on 26 December 2010; the devastating 6.3 magnitude earthquake on 22 February 2011 that struck near Lyttelton on the Port Hills; the 5.7 and 6.3 magnitude earthquakes on 13 June 2011; and the 5.8 and 6.0 magnitude earthquakes on 23 December 2011.

The 22 February earthquake in particular severely damaged properties and infrastructure throughout the eastern suburbs of Christchurch, and forced the virtual abandonment of the central business district, which still remains largely off-limits. We have included a number of images which show how our network was affected by the major earthquakes in Section 3.2.2 of this proposal. Section 3 also includes a detailed description of the damage sustained following each major earthquake and our response to each event.

6.2.3 Risk mitigation and management

During the mid 1990s we took part in an “engineering lifelines” study which examined how natural disasters would affect Christchurch. That prompted us to spend $6 million on seismic protection work and a further $35 million building resilience into our network.

Many older brick buildings in Christchurch were hard hit in the initial earthquake and ensuing aftershocks, but strengthening of Orion’s 271 brick substations (of the 248 network substation buildings and the 283 distribution substation buildings) meant none sustained serious damage in the September 2010 earthquake. Only a small number were damaged in the February 2011 earthquake.

Standard building substation strengthening compared to the distribution substation on the right which had been decommissioned prior to the earthquake and was un-strengthened (it was no longer owned by Orion).

Some of our preventive measures cost very little; for example, the 10 cent plastic ties which prevent batteries for our substation computers falling off the wall and smashing. Our transformers are bolted down, a lesson learned from the 1987 Edgecumbe earthquake where large transformers fell over leaving some areas without power for weeks.

Darfield - bolting down solution - note the additional support beams utilised to minimise turnover

We also reinforced bridges carrying cables across rivers. The benefits of this work can be seen in Dallington where a footbridge strengthened to carry a cable performed superbly, allowing the power to keep flowing, while another unreinforced footbridge 500 metres away was dramatically twisted.

66kV cable bridge over the Avon River showing strengthening work

Earthquake damage to a walk bridge nearby to 66kV cable bridge

Without our pre earthquake strengthening work, it's likely that our total earthquake repair costs would have been considerably higher, with damage to Canterbury's economy due to longer outages many times this again. In terms of hours without power, the impacts would have been much worse, with further weeks of continuous power cuts in parts of Christchurch and Canterbury.

We also maintain "Mutual Aid Partner" agreements with other South Island electricity distribution companies to provide support in situations where we are affected by large scale natural disasters. This support was vital in the aftermath of the February earthquake.

Risk management policy

We have developed many of our response techniques and risk management strategies as a result of earlier major events over the past 20 years. The following is an extract from our 2010 Network Quality Report which we published in July 2010, before the earthquakes struck:

2010 network quality report (extract)

Risk management

Risk management is integral to how we manage our electricity distribution network. We have designed our network to cope with a range of potentially damaging effects, such as:

- natural disaster
- earthquakes
- storms
- network asset failure
- contaminants entering the environment.

We recognise that risk cannot always be eliminated, as natural disasters can take various forms and differ in severity. Where risk cannot be eliminated, we use emergency training, staff competency, safe work practices, planning and network design to control the level of risk. Detailed information on our risk management is contained in our published asset management plan.

Network improvements to minimise risks

Earthquakes and storms are our network's major natural event risks, and we continue to invest significant time and money to ensure the network is protected against such events.

To cost-effectively minimise overall risk to our network we have:

- spent approximately $13m to install additional 66kV transmission capacity from a second point of supply, Bromley, to the central city. This cable, combined with numerous diesel generators around the city, gives the Christchurch CBD a more secure power supply than in Auckland or Wellington CBDs
- spent approximately $6m on earthquake strengthening for bridges, cable supports and buildings. All of our district substations and all major 33kV and 66kV cables now meet a seismic structural standard. Around 98% of Orion-owned network and district substations also meet the standard
- addressed communications risk at the two main communication sites serving Christchurch and surrounds – Sugarloaf and Marley's Hill. Generators now back up the primary network feed to these sites and we have replaced 'high risk' overhead supply lines with underground cable
- improved security of power supply to the airport by installing a cable to allow power supply from both Harewood and Hawthornden district substations. Backup generation is also located on site

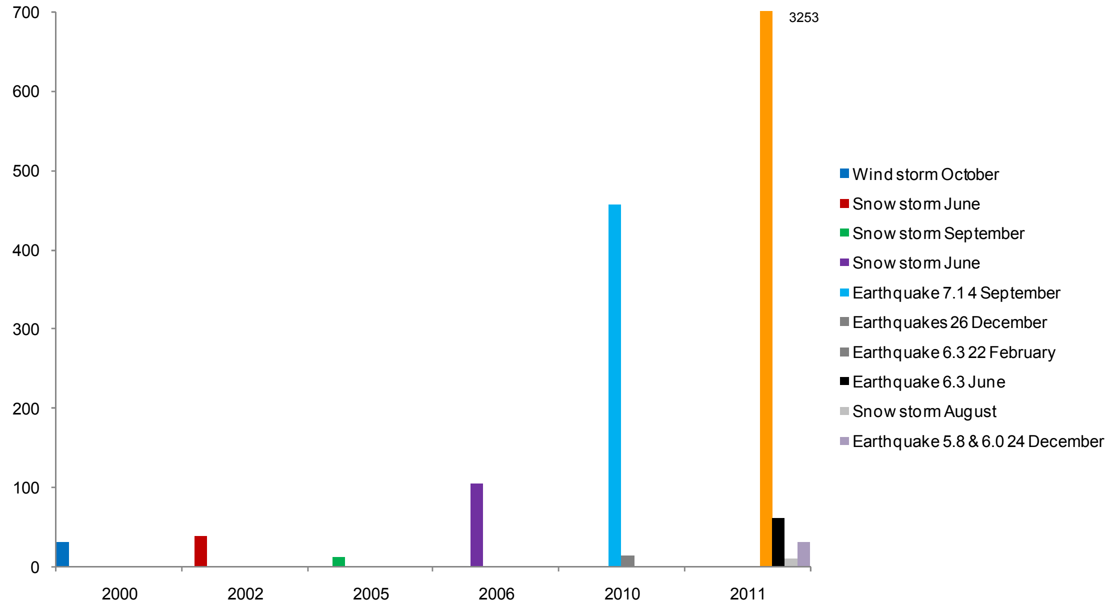
- located an 800kVA generator in Lyttelton to mitigate any loss of power to the port.

We regularly contribute to emergency readiness programmes, and our backup control centre is located off-site so we can continue to function if anything happens to our primary control centre (located in the first floor of our head office, to avoid flood risk).[4]

In recent years, we have reduced the risk of a major asset failure through periodic in-the-field electrical testing of equipment (partial discharge testing), replacing joints between 66kV cables (to prevent the mechanical problems that can occur when cables expand as they warm up) and introducing more ripple injection plant around the network to help reduce peak load.

While our outage management and response policies, and major event planning placed us in a very good position when the earthquakes struck, the earthquake impacts were unprecedented, as demonstrated on the chart below.

Major events which have resulted in outages greater than 10 SAIDI minutes since 2000



From the chart it can be seen that the other major SAIDI impacts are caused by snow storms and high wind events, which are predominant in Canterbury. While we design parts of our network to accommodate snow loadings, economic analysis shows that it is not cost-effective to design and reinforce the network to withstand severe weather events. The DPP quality limits acknowledge this and include allowances for normal year on year variation: an EDB is only considered to have breached its DPP reliability limits if it exceeds either the SAIDI or SAIFI limits in two out of three consecutive years.

Our risk management approach best prepares our network and our responses to mitigate the impact of extreme weather and earthquake events.

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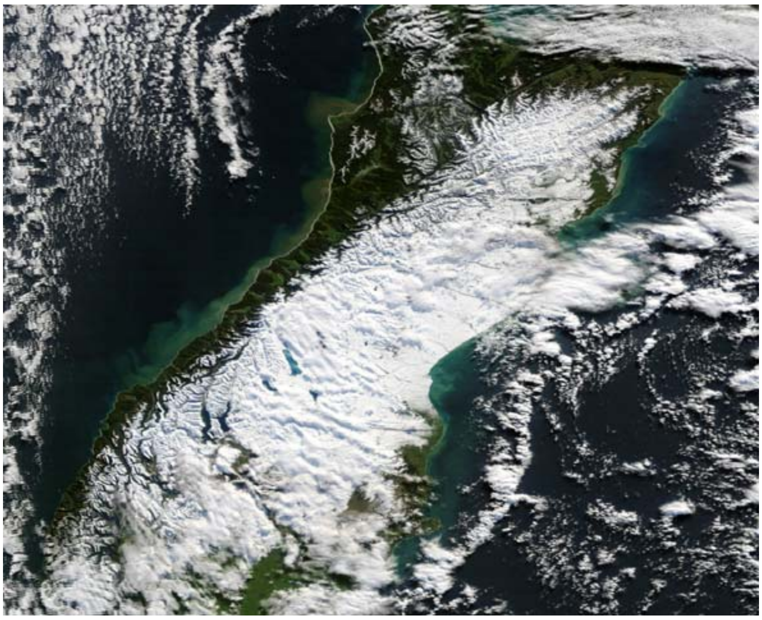
[4] We are currently using our back-up site as our head office has had to be demolished as a result of earthquake damage.

South Island covered in snow and response vehicle hindered by snow conditions



One of the mechanisms that mitigates the impacts of extreme weather events and earthquakes is our system security planning. This is described in Section 6.2.7.

6.2.4 Our immediate response minimised the impact of outages

Orion responded quickly to minimise the impact of the earthquake outages. Approximately three quarters of consumers lost power in the September 2010 earthquake, by the end of that day we had restored 90%, and by the end of the week supply was restored to virtually all consumers that wanted power.

Following the 22 February 2011 earthquake, we immediately called on help from other EDBs (our mutual aid partners), employed local electrical contractors, and diverted all of our contractors from planned work to repair and fault restoration. In addition to our regular contractors, we soon had more than 240 extra fault staff working on repairs.

In some areas (particularly the eastern suburbs) we were unable to restore supply quickly due to the extent of damage to underground cables. We isolated faults and installed temporary generators to restore supply while we worked on repairing cables.

In addition to our own generators, we sourced generators from a number of providers and other distribution companies. At one point we had 25 generators operating and we were providing approximately 9,000 litres of diesel per day to keep them running. We progressively removed the generators as normal supply was restored, with the last being removed on 18 April 2011, almost two months after the earthquake. In all, we used approximately 350,000 litres of diesel in the generators used to provide alternative supplies to consumers.

Approximately two thirds of consumers lost power in the February earthquake. By the end of the next day we had restored 50%, and by the end of the week 86%. With the exception of cordoned areas (and feeders originating within cordoned areas), we restored all consumers who wanted power within 24 days. Within four months we had completed our last 11kV cable repair that could be safely fixed and we were promptly responding to cable faults as they occurred.

Our emergency measures included building a new zone substation in Rawhiti Domain off Keyes Road in New Brighton to replace the severely damaged Brighton zone substation.

We also built two 66kV overhead lines to bypass damaged sub transmission underground cables. The first extends from the grid exit point in Bromley to our damaged Pages Road substation and from there to our new substation in Rawhiti Domain, over a distance of four km. The second is a four and a half km line from the grid exit point in Bromley to our Dallington substation in Coopers Road.

New Rawhiti zone substation and Bromley-Rawhiti 66kV temporary overhead line

Our own head office buildings, including our primary control centre, were badly damaged in the 22 February earthquake and we were forced to relocate to our “hot site”. The hot site is a live and operational network control centre that we maintain for such an emergency and is located in our Armagh district substation adjacent to our (now demolished) head office buildings.

Our staff and contractors spent much of the first few days isolating hundreds of damaged properties at the request of consumers or under the instruction of emergency services. Three months after the 22 February 2011 earthquake, power remained off in some areas of the cordoned off CBD. The power remained off due to a combination of remaining faults, access restrictions and Civil Defence / CERA instructions. In addition, a significant number of consumers could no longer take power following the earthquake due to property damage.

Our temporary (hot site) control room – February 2011

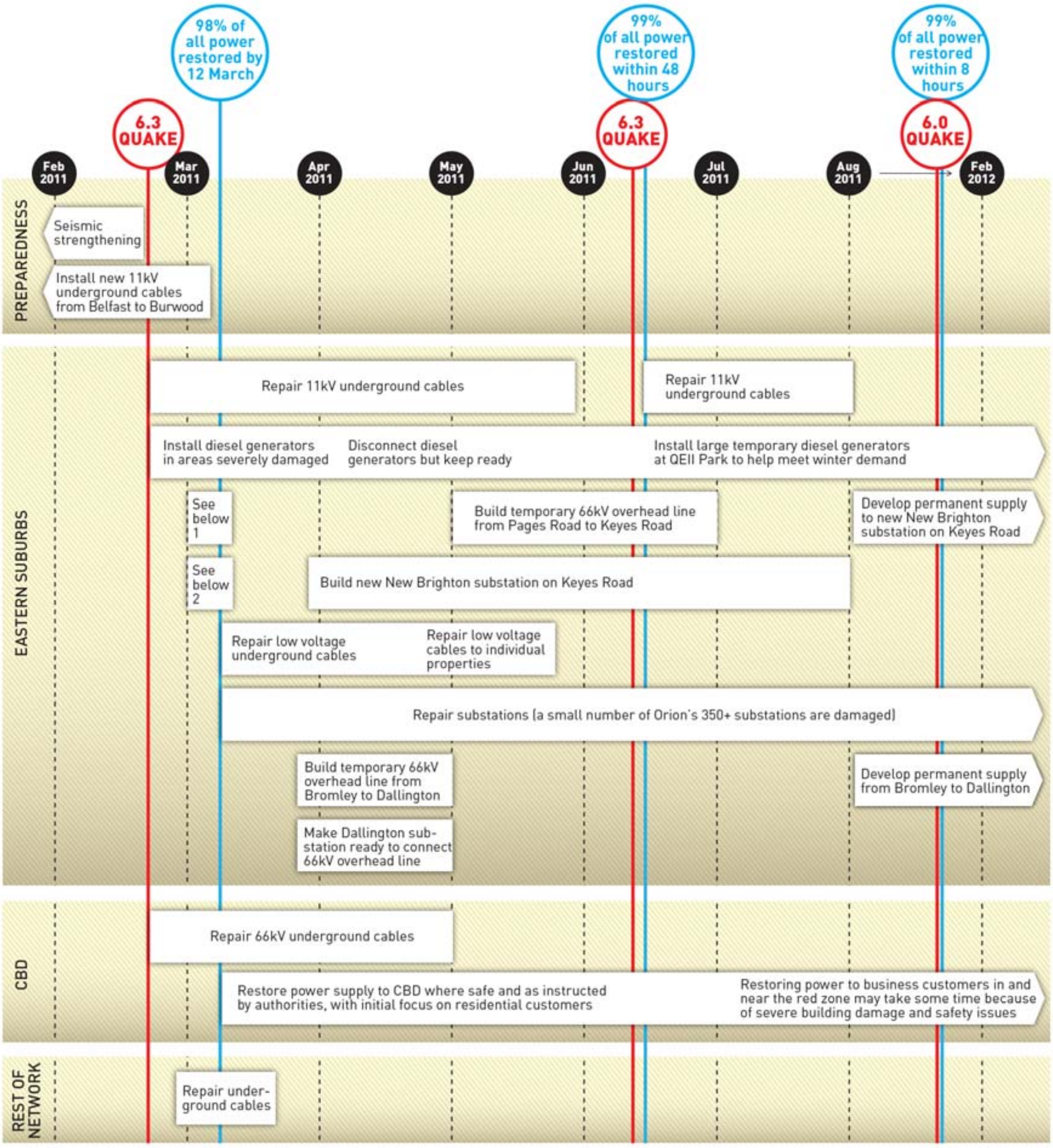
Further supply disruptions occurred following the June 2011 and December 2011 earthquakes. In June approximately 25% of consumers lost power and 99% were restored within 48 hours. In December approximately 20% were affected, and 99% were restored on the same day.

Our past investment in network resiliency, especially in our key substations, and diversity, significantly mitigated and minimised the earthquake impacts for consumers and the wider community.

6.2.5 Network components affected

The earthquakes have impacted our network in a number of ways. The following timeline illustrates the damage incurred and our immediate response, undertaken in the period following the earthquakes. The significant response effort included building temporary lines and a new zone substation and repairing hundreds of cable faults. Our strengthening of substations carried out before the earthquakes, and our very good levels of network resilience meant that we were able to respond quickly and restore power to large amounts of the network in a short period of time.

Earthquake impact and response timeline

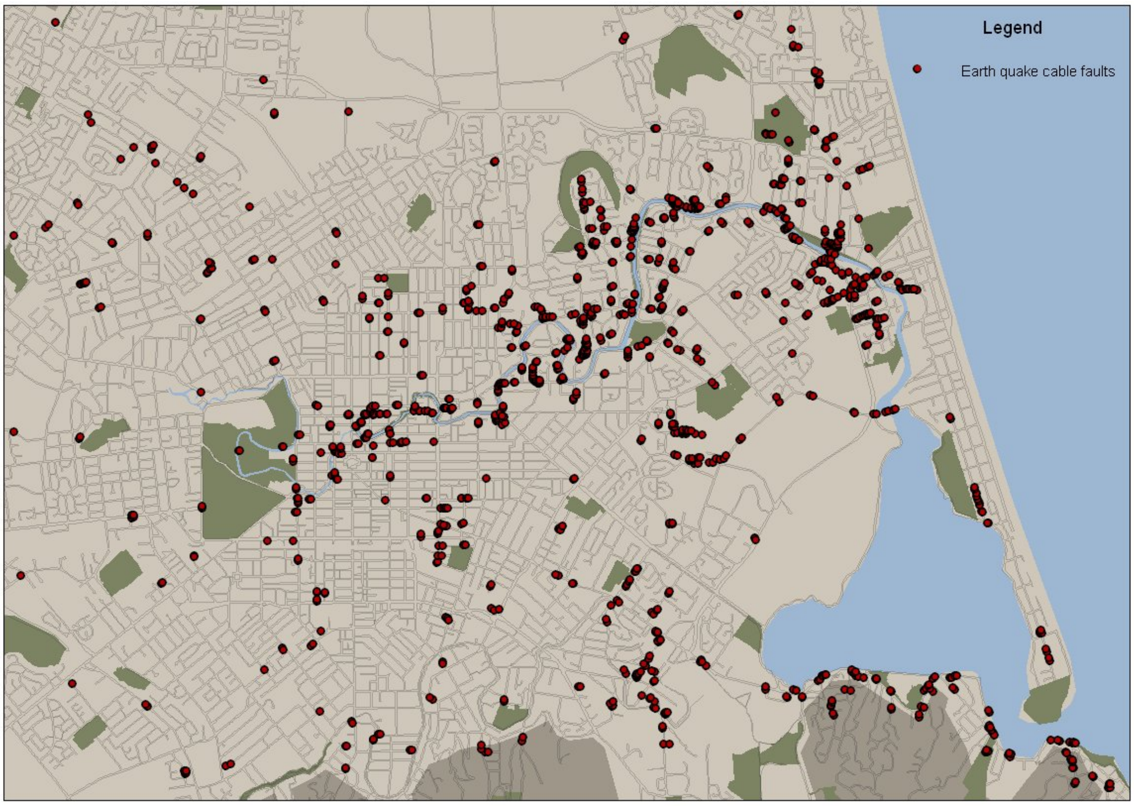


1) Build emergency 3.5km 66kV overhead line to supply existing New Brighton substation at Pages Road.

2) Install temporary transformer at New Brighton.

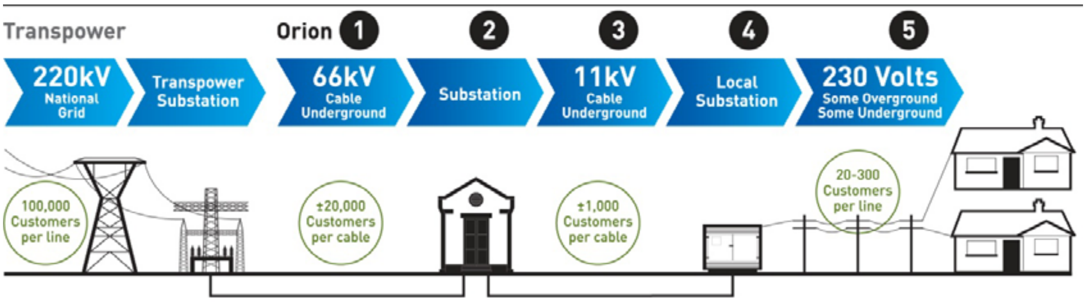
The impact on our urban network has been severe and a large amount of our response efforts were focused on assets in the eastern suburbs and the CBD. The following diagram illustrates the high incidence of high voltage cable faults caused by earthquakes that were resolved in the period following the earthquakes.

High voltage cable faults from earthquakes



Current status of our repair programme

The major components of our network are shown in the diagram below, labelled 1 – 5.



In the following table we set out for each of our five core network components:

- the combined impacts of the earthquakes since September 2010
- the work completed to date to restore power
- the levels of service that the network is currently operating at
- our progress to date in our earthquake recovery programme
- our projected timeframe for earthquake recovery.

All of our major emergency repair work was completed by September 2011. Residents and businesses across our network area can now use power as normal with the exception of the CBD red zone. However, our restoration and rebuilding of the network is ongoing. A summary of the current status of our repair programme as at November

2012 is presented below. In it, we use the following terms to explain our expected level of service.

- Temporary service: Service restored using temporary or non-standard solutions providing normal or lower levels of service
- Impaired service: Service restored to normal levels of service (but with possible lower levels of reliability) utilising conventional asset configurations but where components of the network are compromised and will require rehabilitation or replacement
- Normal service: Service restored to normal levels of service where network components require only normal levels of operations and maintenance from now on.

Current status of repair programme

Network Component	Impact of quakes	Work completed to restore power	Current level of service	Progress to date	Timeframe for recovery
❶ 66kV network	50% of cables known to be damaged – 30km out of a total of 60km	Built two temporary 66kV overhead lines from Bromley to New Brighton and Dallington to replace four underground cables which were damaged beyond repair	North-eastern Christchurch – temporary service Rest of Christchurch classified as impaired service while assessments are carried out	North-eastern Christchurch – assess community needs and design and build permanent replacements for temporary lines Rest of Christchurch – assess cables for damage then schedule any necessary works 45% of assessments are complete 26% of repairs are complete	3 – 6 years

❷ Zone and building substations	Four of 314 Orion owned substations severely damaged 268 privately owned substations have sustained some damage	Built a new zone substation in Keyes Road, New Brighton to replace the damaged Bexley Road and Pages Road substations Two further substations have been repaired or replaced	Impaired service	All zone substation buildings have been assessed 11% of repairs are complete Simeon Quay landslide damaged the main substation supplying Lyttelton. A review is under way	3 – 5 years
❸ 11kV underground network	410 cables out of 6,622 have been damaged 1000+ faults A further 10 cables damaged as a consequence of 23 December quake	100% of all known faults have been repaired	Classified as impaired service while assessments are carried out	Recheck and assess cables for damage hidden underground 0.8% of assessments are complete 0% of repairs are complete	3 – 6 years
11kV overhead network	3,248 km of network. Some damage including cracked insulators	100% of all known faults have been repaired	Classified as impaired service while assessments are carried out	58% of assessments are complete 58% of repairs are complete	3 – 5 years
❹ Local substations (kiosks)	3,392 local substations. Some substations have moved on their foundations	All substantial damage has been repaired	Classified as impaired service while assessments are carried out	All local substations have been assessed and findings collated 100% of assessments are complete 6% of repairs are complete	3 – 5 years

❺ 400V overhead network	3,059 km of network. Some damage, including poles which have sunk or are on a lean due to liquefaction	Repairs to make safe have been completed	Classified as impaired service while assessments are carried out	81% of assessments are complete 38% of repairs are complete	3 – 5 years
Main office/network control room	Main office building badly damaged and evacuated. Computer system servers compromised by the damaged building	Relocated control centre to our ‘hot site’ and established temporary accommodation Sourced and commissioned a portable data centre and standby generation	Impaired service	Build new administration centre to ‘Level 4’ building standard. A site has been purchased. The existing building on the new site has been demolished and work on the new building has commenced Our 1939 and 1984 Manchester Street buildings have been passed to CERA for demolition. The demolition is complete	1 year

Variables outside our control that will affect our rate of recovery

Some variables will impact on how and when we restore parts of our electricity network. These factors include:

- the rate at which buildings are demolished, particularly in the CBD. We can’t fully assess our network in the central city red zone, or plan repairs with any level of certainty, until demolitions are complete
- more than 650 CBD buildings had been demolished by mid 2012 and this number is projected to exceed 1,100
- the rate at which people request new connections to the network
- population movement out of the residential red zone
- the results of geotechnical assessments
- the results of public consultation about options for permanent high-voltage power supply into north-eastern Christchurch
- any further significant aftershocks.

6.2.6 Outage and restoration policies and procedures

Network management system

In November 2011, we commissioned an outage management system to operate under our ‘PowerOn’ SCADA network management system. Significantly, the new system maintains a ‘live model’ of our high voltage network which includes information on consumer connection points.

For planned outages and following network faults, our network controllers follow sequential operating orders to carry out switching and configuration changes on the network to bypass affected assets and facilitate planned or remedial work. At each point during these operating orders PowerOn determines and records the number of connections affected, together with switching points and switching times.

Prior to using this system, our hard-copy operating orders were manually interrogated to determine the number of connections affected. This required us to run a trace on our separate GIS mapping system to determine the number of consumers affected, with adjustments where the GIS configuration did not match the network configuration during outages.

In all cases, the control centre reliability log information is then loaded in a reliability database, and reliability statistics are queried from this database as required. To establish our system average reporting measures, the total number of connected consumers on the network is obtained from our connections database. We maintain details of all our network connections on this database, and we regularly undertake reconciliations with the Electricity Authority Registry.

We are further developing our PowerOn system to collate a record of outage results over time, and this will further enhance our capabilities in future. Currently, we are maintaining our control centre reliability log by manually recording the results of operating orders including information for:

- substation name
- feeder name
- switching device where isolation occurred
- asset type affected
- cause of interruption
- time/date off
- time/date for each restored section
- number of consumers affected in each restored section
- explanatory notes.

The 22 February 2011 earthquake occurred before we commissioned the outage management component of our PowerOn system. The magnitude of the damage required us to take a different approach to outage recording for this event. Significant network reconfiguration was required to bypass damaged assets and progressively restore supply following the earthquake. We also installed generators in a number of situations.

With ongoing configuration changes, it was not possible to use a network-trace in the largely static GIS network model to establish the number of connections affected. Instead, our control centre engineers assessed the number of connections affected based on loading levels and knowledge of the network (rather than using the GIS network trace).

Orion’s outage and restoration processes are set out in the following policy documents:

- NW20.40.01 Contingency Plan – Equipment Failure
- NW20.40.02 Contingency Plan – Emergency Generators
- NW20.40.03 Continuity Plan – Loss of Supply
- NW20.40.05 Disconnection of Demand as Required by ECom Rules
- NW20.40.08 Contingency Plan – Relocating the Control Centre
- NW20.40.09 Contingency Plan – Security of Supply, Participant Outage Plan
- NW70.60.04 Business Continuity Plan – Infrastructure Management
- OR.00.00.07 Major Outage Communication Plan
- OR00.10.17 Building Emergency Plan – 200-210 Armagh St

6.2.7 System security planning

Security of supply is the ability of a network to meet the demand for electricity in certain circumstances when electrical equipment fails. The more secure an electricity network, the greater its ability to continue to perform or the quicker it can recover from a fault or a series of faults. Security of supply differs from reliability – reliability is a measure of how the network actually performs and is measured in terms such as the number of times supply to consumers is interrupted.

We strive for overall resiliency in terms of security of supply, but also in terms of our processes, systems, capabilities and culture. We believe this is in the long term interests of our consumers as it enables us to provide electricity at a quality which is consistent with the needs of our community, while recognising that we must provide this service at a fair price. This ultimately limits how much we are able to invest in our network security.

With community input we developed our first security of supply standard in 1998, which forms the underlying basis for our reliability. It is based on the United Kingdom's P2/6 which is the regulated standard for distribution supply security in the UK. Currently there is only one industry guide published by the Electricity Engineers' Association of NZ (EEANZ) and no regulated national standard is in force. The underlying principle for security of supply is that the greater the size or economic importance of the demand served, the shorter the interruption time that can be tolerated.

In 2006, we reviewed our standard. In reviewing the standard we were conscious of the need to balance investment in our network (which influences the performance of our network) with the value which consumers place on reliable electricity supply. This theme continues to influence our thinking, for example in how we prioritise repair work versus improving the resilience of our network. This is discussed further below.

Consumer consultation

In our 2006 review we undertook substantial consultation with stakeholders on our proposed security of supply standard. We proposed a number of changes. The implications for consumers of our proposed changes to the standard were that:

- we would maintain our historical levels of network reliability for existing Christchurch city consumers
- electricity reliability in new subdivisions on the outskirts of Christchurch would have slightly lower levels of network reliability, by around fifteen minutes per consumer every three years, on average

- we would maintain historical levels of network reliability for rural consumers.

We consulted with the following stakeholder groups on our proposals:

- Christchurch City Council
- Selwyn District Council
- Environment Canterbury
- Meridian Energy
- Contact Energy
- Mighty River Power
- Canterbury Regional Energy Group (Meridian/Transpower/Chamber of Commerce/ECAN)
- Retailer CEOs
- Major Electricity Users Group
- Chamber of Commerce
- Canterbury Manufacturers Association
- The Meridian Community Group which consists of Christchurch Budget Advisory Services, Power Consumers Society, Greypower, Lincoln Community Care, a representative of the disability sector, the Tenants Protection Society.

No party indicated that our proposed standard needed alteration. A number of comments were received commending us on our efforts to discuss this matter with community and consumer groups and the amount of consideration we had given the issue.

Accordingly we adopted our revised security of supply standards and incorporated them into our subsequent AMPs. These standards form the basis of our system planning, design and performance of our network.

Trade-offs between electricity distribution prices and network resilience and reliability have been a focus for us, and remain so post earthquake. Generally, the more we invest in our network, the more resilient and reliable our network becomes.

The key trade-off is that the more we invest, the higher our prices become, as we need to recover our costs. Over the decade up to the earthquakes, we improved the quality of supply for our consumers, while constraining our annual average price movements to less than CPI over the same period. As demonstrated in Section 6.2.1 our pre-earthquake reliability performance is well within the top quartile of NZ EDBs. We have achieved this with average prices which are lower than the median of NZ EDBs.

We are committed to seeking our consumers' views on the trade-offs between price and service quality to ensure that our network investment decisions consider consumer preferences. Our most recent consultation undertaken as a direct consequence of this CPP proposal is summarised in our CPP application.

Our proposal to increase prices to consumers partly reflects our plans to restore the performance of our network to pre earthquake standards, over time. These standards were developed via earlier consultation. The recent consultation we have undertaken on our CPP proposal has not identified demand for reduced network performance.

Network security of supply standard

The thresholds for each demand/location group which are set out in our security of supply standard tend to err on the side of caution and generally provide a level of security that is slightly above the requirements of the average consumer connection. This is because within each demand/location group there is a mix of consumer types, some with more critical needs than others. For example, our (pre-earthquake) analysis determined that it was appropriate to provide a slightly higher level of network security for the Christchurch CBD. This approach ensures that consumers who place a high value on security of supply are adequately serviced in areas where a mix of consumer types exists.

Our current network security of supply standard is set out below.

Network security of supply standard

Class	Description	Load Size (MW)	N-1 Cable, line or transformer contingency	N-2 Cable. line or transformer contingency	Bus fault or switchgear failure
Urban Transpower GXPs					
A1	Lines, buses and supply banks	15 - 200	No interruption	Restore within 2hrs	No interruption for 50% and restore rest within 2hrs
Rural – Transpower GXPs					
B1	Lines, buses and supply banks	15 - 60	No interruption	Restore within 4hrs (1)	No interruption for 50% and restore rest within 4hrs (1)
B2	Supply banks	0 - 1	Restore in repair time	Restore in repair time	Restore in repair time
Urban – Orion network					
C1	Zone substation with CBD or special industrial load	15 - 40	No interruption	Restore within 1hr	No interruption for 50% and restore rest within 2hrs
C2	Zone substation without CBD or special industrial load	15 - 40	No interruption	Restore within 2hrs	No interruption for 50% and restore rest within 2hrs
C3	Zone substation or 11kV ring with CBD or inner urban load	2 - 15	Restore within 0.5 hr	Restore 75% within 2hrs and the rest in repair time	Restore within 2hrs
C4	Outer, mainly residential zone	4 - 15	Restore within	Restore 75% within 2hrs and the	Restore within

	substations		2hrs	rest in repair time	2hrs
C5	Inner 11kV distribution feeder	0.5 - 2	Restore within 1hr	Restore in repair time	Restore 90% within 1hr and the rest in 4hrs (use generator)
C6	Outer, mainly residential 11kV distribution feeder	0.5 - 4	Restore within 1hr	Restore in repair time	Restore 90% within 1hr and the rest in 4hrs (use generator)
C7	11kV distribution spurs	0 - 0.5	Use generator to restore within 4hrs	Restore in repair time	Use generator to restore within 4hrs
Rural – Orion network					
D1	Subtransmission feeders	15 - 60	No interruption	Restore within 4hrs (1)	No interruption for 50% and restore rest within 4hrs (1)
D2	Zone substations and subtransmission feeders	4 - 15	Restore within 4hrs (1)	Restore 50% within 4 hrs and the rest in repair time (1)	Restore within 4hrs (1)
D3	Small zone substations and 11kV distribution feeders	1 - 4	Restore within 4hrs (1)	Restore in repair time	Restore 75% within 4hrs and the rest in repair time (1)
D4	11kV distribution spurs	0 - 1	Restore in repair time	Restore in repair time	Restore in repair time

(1) Assumes the use of interruptible irrigation load for periods up to 48 hours

Current network not consistent with security of supply standards

In the short term, regardless of the future incidence of earthquakes, our underlying reliability and resiliency has materially altered and we are not able to meet our system security standards across our network. A number of factors have affected our underlying reliability, including:

- many assets, particularly underground cables, have been damaged during earthquakes but do not fail until sometime later. Often this delayed failure will occur when seasonal changes lead to wetter conditions and a higher water table resulting in moisture entering damaged insulation, or as the network becomes more heavily loaded during winter. We have already seen these effects on our network. It would be cost-prohibitive to replace cables on a precautionary basis, and it is not always possible to establish if earthquakes were the original cause of any specific failure

- some areas of our network are operating with a lower level of security than we would normally provide. This occurs where our backup supply systems are damaged, or where our primary supply systems have been damaged and we are relying on backup systems. In these situations, outages last until we can fix a fault, rather than being able to restore supply via alternative routes while repair work is carried out
- increased civil works in relation to repair work for other services (roading, water, waste water and telecommunications) has led to a higher incidence of third-party damage to our assets. This is expected to continue throughout the CPP period as the Christchurch rebuild works proceed. Orion currently has a number of on-going legal disputes against various contractors. For example we have recently filed court proceedings against two companies that damaged a 66kV sub-transmission cable while repairing a broken water main
- we have installed a number of temporary over-head high-voltage feeders to restore supply in our eastern suburbs. A normal attribute of overhead lines is that they provide a lower level of reliability than underground cables. We have observed a number of outages that have affected large areas of the city as a result of faults (such as bird strike) on these lines
- there is an increasing number of requests for planned outages as the demolition work in the city continues, and as we begin to enter a long rebuilding phase. Much of this work requires alterations to our network which result in planned outages.

As a result, we consider that our network security levels and associated reliability performance has fundamentally changed, and the current regulatory methods which assess our reliability performance against historical levels are no longer appropriate in the short to medium term.

Network architecture review

Our network reliability as measured by SAIDI and SAIFI is ultimately determined by our network architecture. As a consequence of the damage to our network we are now reviewing our network architecture. The outcome of this review will set the long term reliability characteristics of our network once fully implemented and increase levels of resiliency. To date we have completed the review of the sub-transmission network and our future sub-transmission planning (including capital expenditure set out in sections 8-9 of this report) reflects these decisions. A summary of this review is included at Appendix 6.

We have also undertaken a review of our 11kV architecture. A summary of this review is included at Appendix 7.

Our requirement for N-2 standard (three 66kV cables for two zone substations) applies to load groups of 80MW and above. This is consistent with the UK P2/6 standard which requires at least partial restoration of load for demand in the range of 60-300MW and greater restoration for loads in excess of 300MW for N-2 events which is ‘almost N-2’.

Our network security of supply standard was developed following a comprehensive study culminating in the publishing of our standard in 2006. This used VOLL figures published by the Electricity Commission and included public consultation, benchmarking and an external review.

The cost to provide this interconnectivity is very modest. By way of example, the proposed link that provides this resiliency in our northern urban loop is the Marshland to McFaddens link (which is to be built after the end of the CPP period). This is primarily required in the longer term to provide uninterrupted N-1 security for Dallington, Rawhiti and Marshlands, so it serves a dual purpose.

Impact of third parties on network resilience and reliability

One of the biggest risks to our planned improvements to network resilience and reliability in the short to medium term is that third parties, including CERA and Stronger Christchurch Infrastructure Rebuild Team (SCIRT), can impact both planned and unplanned outages as follows:

- risk to planned outages: CERA and SCIRT currently control the speed, intensity and priorities of the Christchurch rebuild. These factors, including the requirement for SCIRT to manage all in-ground civil works, will impact Orion's level of planned outages. We may have to defer our own planned work programme (including the work required to improve to network resilience) if the incidence of CERA/SCIRT driven planned outages is significantly higher than present levels. This would result in a slower rate of improvement in overall network resilience and reliability
- risk to unplanned outages: CERA and SCIRT will also influence the level of work undertaken by third party contractors as a result of their rebuild plans. This is expected to have a direct impact on the level of unplanned outages, for example as a result of accidental cable strikes. If unplanned outages caused by third party contractors significantly increases above present levels we may also have to defer our own planned work in order to respond to unplanned outages.

Prioritisation

Scheduling of network projects will take into account a number of factors. We need to prioritise our network response in order to manage the large number of tasks to be completed and accommodate the needs of our consumers and other external agencies. Of particular relevance for the CPP period are the following:

- satisfying individual or collective consumer expectations: We consider satisfying consumer expectations as the most important factor and give priority to the constraints that are most likely to impact supply to consumers through extended or frequent outages or compromised power quality
- coordination with NZ Transport Authority (NZTA), CERA, SCIRT and local authority civil projects: These parties are responsible for key civil infrastructure projects such as the new Christchurch Convention Centre and central city redevelopment projects such as the Avon River Precinct which has recently commenced. As the shape of the redevelopment of Christchurch continues to evolve and we must maintain some flexibility in our own planning to accommodate the city's needs as they become more certain. We are doing everything we can to gather the information we need about the city planning in order to develop and implement our own plans and to contribute to the decisions of others as required

- Our asset replacement programme: We extensively review areas of the network where scheduled asset replacement programmes occur to ensure the most efficient and cost-effective solution is sought which integrates with the current and long-term network development plan. Due to the earthquakes, some replacement programmes were deferred. We have initiated a cable testing programme to inform future replacement work
- Resources: We need to make the best use of skilled resources for planning, scheduling, tendering and contracting. This may require some prioritisation between improving resiliency, managing CERA and SCIRT initiated outages and responding to unplanned interruptions.

After assessing the above factors, the final decision to undertake projects depends on urgency and resources available. We use our knowledge, research and assessments of risk to determine network priorities. We place a lot of emphasis on understanding our network. Other factors also apply, such as seasonal timing (to avoid taking equipment out of service during peak loading periods: winter for urban projects and summer for rural projects); contractor workflow; and the sequencing of interconnected projects. Professional engineering judgements based on our experience and expertise, are used when making these decisions.

6.3 Current reliability performance

IM 5.4.5(b)

6.3.1 DPP method

The Electricity Distribution Services Default Price-Quality Path Determination 2010 (2010 DPP) sets out the method for deriving the quality standards that each EDB is required to comply with for the FY11-FY15 regulatory period.

The DPP quality standards that apply to each EDB comprise a SAIDI and a SAIFI standard, determined using the following method:

- establish a historical outage Reference Dataset comprising all Class B (own network planned) and Class C (own network unplanned) outages for the five year period 1 April 2004 – 31 March 2009
- collate the dataset into daily SAIDI and daily SAIFI
- exclude all zero event days
- calculate a Boundary value for each of SAIDI and SAIFI as follows:

$$\mathbf{B}_{SAIDI} = e^{(\alpha SAIDI + 2.5\ \beta SAIDI)} \qquad \mathbf{B}_{SAIFI} = e^{(\alpha SAIFI + 2.5\ \beta SAIFI)}$$

where:

αSAIDI is the average of the natural logarithm (ln) of each daily SAIDI value in the non-zero dataset

βSAIDI is the standard deviation of the natural logarithm (ln) of each daily SAIDI value in the non-zero dataset

αSAIFI is the average of the natural logarithm (ln) of each daily SAIFI value in the non-zero dataset;

βSAIFI is the standard deviation of the natural logarithm (ln) of each daily SAIFI value in the non-zero dataset.

- normalise the Reference Datasets as follows:

For any day in the Reference Dataset where the daily SAIDI value is greater than B_{SAIDI}:

(i) replace the daily SAIDI value with B_{SAIDI}

(ii) replace the daily SAIFI value with B_{SAIFI} if the daily SAIFI value for that day exceeds B_{SAIFI}

calculate the SAIDI Reliability Limit ($SAIDI_{LIMIT}$) is as follows:

$SAIDI_{LIMIT}$ = μSAIDI + σSAIDI

where:

μSAIDI is the average annual SAIDI value in the Normalised Reference Dataset, which is given by:

$$\frac{\text{Sum of daily SAIDI values in the Normalised Reference Dataset}}{5}$$

σSAIDI is the standard deviation of daily SAIDI values in the Normalised Reference Dataset multiplied by $\sqrt{365}$

- calculate the SAIFI Reliability Limit ($SAIFI_{LIMIT}$) is as follows:

$SAIFI_{LIMIT}$ = μSAIFI + σSAIFI

where:

μSAIFI is the average annual SAIFI value in the Normalised Reference Dataset, which is given by:

$$\frac{\text{Sum of daily SAIFI values in the Normalised Reference Dataset}}{5}$$

σSAIFI is the standard deviation of daily SAIFI values in the Normalised Reference Dataset multiplied by $\sqrt{365}$

6.3.2 Our DPP quality standards

Our DPP Quality Standards (SAIDI and SAIFI Limits) were derived from information collated in our Reliability Database. We calculated our DPP Limits as follows:

- we extracted daily records on the sum of consumer minutes and sum of consumers affected during Class B (planned) interruptions and Class C (unplanned) interruptions on our network over the reference period (1 April 2004 to 31 March 2009)
- we then excluded days with no outages to develop a non-zero dataset
- using the above data and data as to the total number of consumers used in the derivation of annual reliability statistics we calculated daily SAIDI and SAIFI
- the SAIDI and SAIFI results are assumed to follow a lognormal distribution and the DPP method establishes Boundary values 2.5 standard deviations from the average

- any days where the SAIDI result exceeds this boundary value is classified as a major event day (MED) and the SAIDI results for that day are "normalised" by reducing them to their Boundary values
- if on the same day, SAIFI exceeds it Boundary, SAIFI results for that day are also normalised.

Orion's results

The SAIDI Boundary value is described by the expression:

$\mathbf{B}_{\text{SAIDI}} = e^{(\alpha\text{SAIDI} + 2.5\ \beta\text{SAIDI})}$

where

αSAIDI is the average of the natural logarithm of each daily SAIDI value, which we have calculated as -2.843

βSAIDI is the standard deviation of the natural logarithm of each daily SAIDI value, which we have calculated as 1.777

Substituting the average and standard deviation gives:

$\mathbf{B}_{\text{SAIDI}} = e^{(-2.843 + 2.5 \text{ x } 1.777)}$

= **4.95**

The SAIFI boundary value is described by the expression:

$\mathbf{B}_{\text{SAIFI}} = e^{(\alpha\text{SAIFI} + 2.5\ \beta\text{SAIFI})}$

where

αSAIFI is the average of the natural logarithm of each daily SAIFI value which we have calculated as -7.574

βSAIFI is the standard deviation of the natural logarithm of each daily SAIFI value, which we have calculated as 1.996

Substituting the average and standard deviation gives:

$\mathbf{B}_{\text{SAIFI}} = e^{(-7.574 + 2.5\text{x}1.996)}$

= **0.075**

The Reference Dataset is then normalised by replacing any daily SAIDI result that is greater than the SAIDI Boundary value with the SAIDI Boundary value, and on these same days, reducing the SAIFI value to the SAIFI Boundary value (if it is greater).

Our Reference Dataset includes two MEDs as follows:

- 19 September 2005: SAIDI of 12.20 reduced to 4.95 and SAIFI of 0.048 remains unchanged
- 12 June 2006: SAIDI of 100.29 reduced to 4.95 and SAIFI of 0.074 remains unchanged.

Both of these days were dominated by outages caused by severe snow storms.

Our reliability limits are then established as one standard deviation above the average for the Normalised Reference Dataset.

The SAIDI limit is described by the expression:

$SAIDI_{LIMIT} = αSAIDI + βSAIDI$

where:

αSAIDI is the annual average SAIDI in the normalised dataset, which we have calculated as 52.99

βSAIDI is the standard deviation of SAIDI in the normalised dataset which is annualised by multiplying it by the square root of the number of days in the year, which we have calculated as 6.74

Substituting the average and standard deviation gives:

$SAIDI_{LIMIT} = 52.99 + 6.74$

= **59.73**

The SAIFI limit is described by the expression:

$SAIFI_{LIMIT} = αSAIFI + βSAIFI$

where

αSAIFI is the annual average SAIFI in the normalised dataset, which we have calculated as 0.676

βSAIDI is the standard deviation of SAIFI in the normalised dataset which is annualised by multiplying it by the square root of the number of days in the year, which we have calculated as 0.100

Substituting the average and standard deviation gives:

$SAIFI_{LIMIT} = 0.676 + 0.100$

= **0.776**

6.3.3 Demonstrating compliance

During the DPP regulatory period, we must submit an annual compliance statement which sets out our compliance or otherwise with its DPP Quality Standards, the $SAIDI_{Limit}$ and $SAIFI_{Limit.}$

Each year Assessed SAIDI and SAIFI values are calculated, which are then compared to their corresponding SAIDI and SAIFI Limits. These are calculated as follows:

- normalise the Assessment Dataset for the Assessment Period. An Assessment Period is one regulatory year within the DPP Regulatory Period. This comprises the following:

For any day in the Assessment Dataset where the daily SAIDI value is greater than B_{SAIDI}:

(i) replace the daily SAIDI value with B_{SAIDI}

(ii) replace the daily SAIFI value with B_{SAIFI} if the daily SAIFI value for that day exceeds B_{SAIFI}

- calculate Assessed values as follows:

(a) The SAIDI Assessed value ($SAIDI_{ASSESS}$) is the sum of daily SAIDI values in the Normalised Assessment Dataset for the Assessment Period

(b) The SAIFI Assessed value ($SAIFI_{ASSESS}$) is the sum of daily SAIFI values in the Normalised Assessment Dataset for the Assessment Period.

This is represented by the following equations:

$$\frac{SAIDI_{ASSESS}}{SAIDI_{Limit}} \leq 1 \qquad \frac{SAIFI_{ASSESS}}{SAIFI_{Limit}} \leq 1$$

Compliance with the DPP Quality Standards is achieved by either:

(a) complying with the annual reliability assessment for that Assessment Period; or

(b) having complied with those annual reliability assessments for the two immediately preceding extant Assessment Periods.

6.3.4 Our DPP compliance position to date

This section describes our reliability results for the first two years of the DPP, FY11 and FY12.

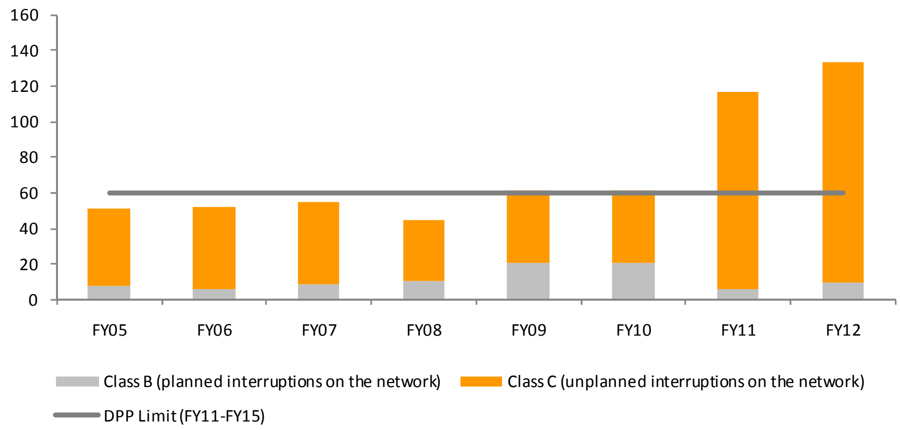
Our actual reliability results (prior to normalising the data for extreme events) were:

Orion's reliability results for the first two DPP assessment periods

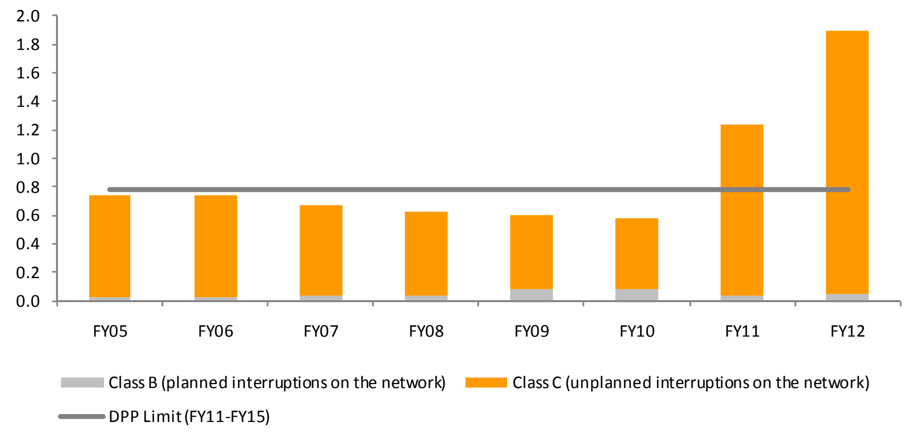
		FY11		FY12	
	Limit	Raw data	Normalised	Raw data	Normalised
SAIDI	59.7	3,811.6	106.3	230.6	133.7
SAIFI	0.78	3.04	1.24	2.22	1.90

Our raw results exceeded our reliability limits for both SAIDI and SAIFI, for both of the first two years of the DPP. Once the results were normalised in accordance with the DPP method, ie: MEDs were identified and the boundary values substituted for the actual daily result. Due to the earthquakes, our FY11 and FY12 results exceed our DPP limits. This is illustrated below.

SAIDI (normalised)



SAIFI (normalised)



At a more fundamental level, it is worth noting we have had difficulty establishing a meaningful measure of reliability in FY11, particularly in relation to areas of the city that were deemed too dangerous to occupy, and were cordoned off. While the power remained off in these areas, there were no consumers wanting supply. The point at which an outage ceases to be an outage, and becomes a normal disconnection is not clear.

Following the 22 February 2011 earthquake, we had a number of semi-permanent outages where we were unable to repair or were prevented from repairing our network assets, and/or there were no consumers in the area to receive supply. To finalise numbers for the year, we manually “ended” these outages at the end of the financial year, on 31 March 2011. After seeking agreement with the Commission, we have accumulated back the outage minutes for these events against the day that the outages began, and the results for these particular days are capped as MEDs.

In the first two Assessment Periods (ie: FY11 and FY12) we have identified 15 MEDs where the daily SAIDI exceeded the boundary value of 4.95. These are summarised in the following table.

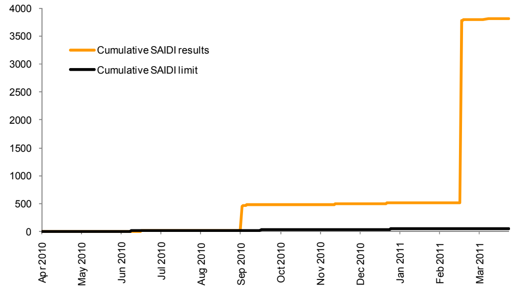
MED events where the boundary value for SAIDI was exceeded

MED	Daily SAIDI adjustment	Daily SAIFI adjustment	Primary Cause
4 September 2010	432.47 reduced to 4.95	0.861 reduced to 0.075	7.1 magnitude earthquake centred near Darfield
5 September 2010	12.59 reduced to 4.95	0.029 unchanged	Total of 232 aftershocks with 5 earthquakes in excess of magnitude 4.5
8 September 2010	12.99 reduced to 4.95	0.323 reduced to 0.075	Total of 138 aftershocks with 3 earthquakes in excess of magnitude 4.5
21 December 2010	5.14 reduced to 4.95	0.028 unchanged	Wind storm affecting rural parts of our network, with norwest winds gusting in excess of

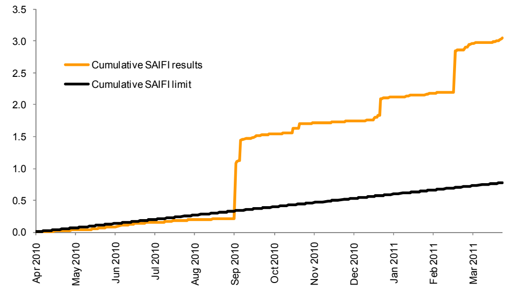
			100km/h
26 December 2010	8.63 reduced to 4.95	0.271 reduced to 0.075	“Boxing Day” earthquake, magnitude 4.9 close to Christchurch CBD
22 February 2011	3260.51 reduced to 4.95	0.650 reduced to 0.075	Devastating 6.3 magnitude earthquake centred under the Port Hills with significant energy release directed at Christchurch CBD
9 March 2011	7.60 reduced to 4.95	0.009 unchanged	Delayed faults from 22 February 2011 earthquake affecting less than 50 consumers in an area that remained cordoned off for an extended period of time
16 April 2011	8.94 reduced to 4.95	0.111 reduced to 0.075	5.3 magnitude earthquake caused a fault in our 66kV supply to a high density urban area for several hours
27 April 2011	6.91 reduced to 4.95	0.064 unchanged	Delayed fault to a communications cable led to loss of supply from one of our significant urban substations for a number of hours
13 June 2011	61.68 reduced to 4.95	0.275 reduced to 0.075	Magnitude 5.9 and 6.4 earthquakes centred under Port Hills, close to Sumner
24 July 2011	5.67 reduced to 4.95	0.018 unchanged	Snowstorm, reported as “The worst snow fall in 15 years blanketed quake-hit Christchurch overnight with up to 30cm of snow covering the city”
15 August 2011	6.16 reduced to 4.95	0.048 unchanged	Snowstorm, reported as “New Zealand's biggest snow storm in 50 years”. In Christchurch there was a little less snow than the snowstorm 3 weeks prior, but the snow was wetter, heavier and the poor weather conditions lasted longer
16 August 2011	6.39 reduced to 4.95	0.037 unchanged	
30 September 2011	9.49 reduced to 4.95	0.061 unchanged	Fault on temporary 66kV overhead line feeding Christchurch eastern suburbs for several hours. Suspected bird strike
23 December 2011	31.22 reduced to 4.95	0.159 reduced to 0.075	Magnitude 5.9 and 6.0 earthquakes centred near the coast close to Christchurch eastern suburbs

Graphing the cumulative SAIDI and SAIFI throughout the assessment periods shows that we remained within our limits until the earthquakes began on 4 September 2010, and the significant impact of the earthquakes.

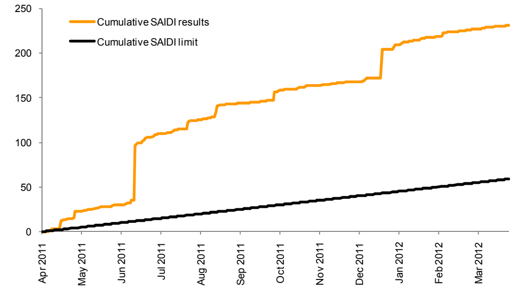
Cumulative SAIDI results - FY11



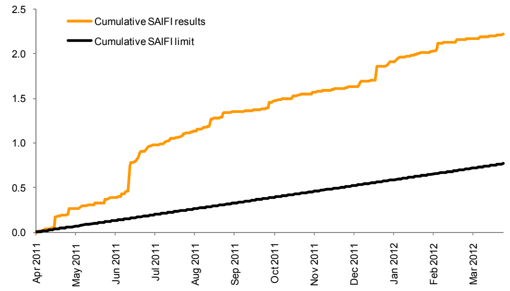
Cumulative SAIFI results - FY11



Cumulative SAIDI results - FY12

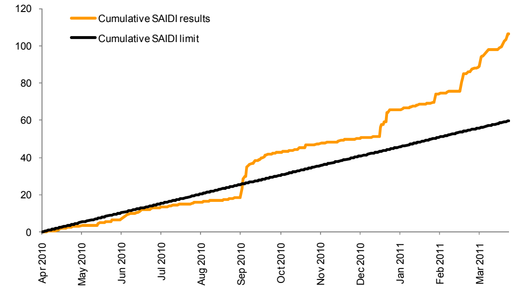


Cumulative SAIFI results - FY12

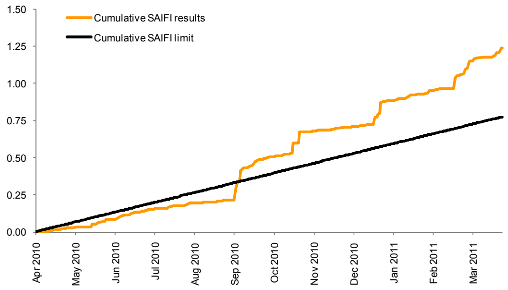


The corresponding graphs of our normalised results show the progression of our reliability results through the two assessment periods.

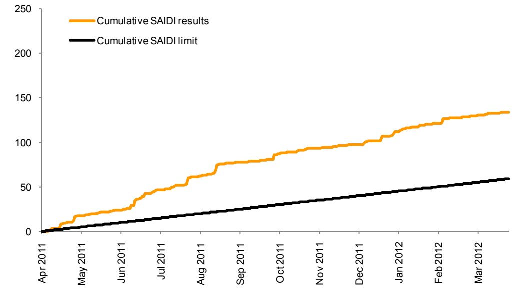
Cumulative normalised SAIDI results - FY11



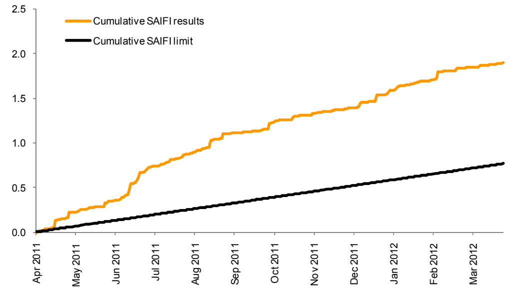
Cumulative normalised SAIFI results - FY11



Cumulative normalised SAIDI results - FY12



Cumulative normalised SAIFI results - FY12



As our assessed SAIDI and SAIFI results for both years exceed their respective limits, we have not complied with the DPP Quality Standards to date. We do not expect that our network reliability will return to pre-earthquake levels for some years yet.

Since the earthquakes, we have experienced a higher number of underground cable faults as damaged cables return to normal loading levels and/or are exposed to moisture. As noted above, we are carrying out a programme of cable testing that is estimated to take more than five years to complete. This timeline is driven by resource prioritisation, availability of cable testing equipment, and the need to perform testing at times when system loadings permits.

We will not fully replace the temporary single circuit overhead 66kV lines in the urban area to provide N-2 security to the Rawhiti and Dallington zone substations until the calendar year 2014.

The significant repair and rebuilding of other infrastructure (roads, water and waste water services) also exposes our assets to a higher risk of damage. In a recent example, a contractor repairing water services in the suburb of Milton, struck one of our 66kV oil filled sub transmission cables, which we had to take out of service and bring in specialist contractors to repair.

6.4 Proposed quality standard variation

IM 5.4.5(a)

Orion is proposing the following quality standard variation.

6.4.1 Proposed SAIDI and SAIFI limits for CPP period

The DPP methodology sets uniform SAIDI and SAIFI limits for the entire DPP period. We are not proposing uniform limits throughout the CPP period. Setting uniform reliability limits for the CPP period will disadvantage consumers and not reflect the impact of the investment provided for in the CPP proposal.

Accordingly in order to reflect the expected improvements in the reliability of Orion's network as network resilience is regained we have set decreasing SAIDI and SAIFI limits over the CPP period. These reflect the expected movement from the current abnormal network circumstances, to more a steady state operating environment consistent with Orion's expenditure plan. They also reflect significant progress towards restoring our service performance to the levels required by our consumers.

The table below shows the proposed SAIDI limit, in comparison to the DPP SAIDI limit. These limits include the normalisation adjustments consistent with the DPP method. Although FY14 falls outside the CPP regulatory period, we have derived an indicative limit for that year, as this has been necessary in order to establish the limits for the CPP years which follow. This also illustrates the transitional improvements we are expecting to make prior to the commencement of the CPP regulatory period.

		Assessment period	CPP period				
SAIDI	**DPP limit**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
µSAIDI	53.0	97.2	94.7	86.5	83.1	75.2	67.0
σSAIDI	6.7	9.3	9.0	8.2	7.9	7.2	6.4
$\text{SAIDI}_{\text{LIMIT}}$	**59.7**	**106.4**	**103.8**	**94.7**	**91.0**	**82.4**	**73.4**

The table below shows the proposed SAIFI limit, in comparison to the DPP SAIFI limit. The limits include the normalisation adjustments consistent with the DPP method. An indicative limit for FY14 year is also shown as this is required in order to establish the limits for the CPP years which follow.

		Assessment period	CPP period				
SAIFI	**DPP limit**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
μSAIFI	0.68	1.29	1.25	1.11	1.07	0.94	0.80
σSAIFI	0.10	0.11	0.11	0.09	0.09	0.08	0.07
$\text{SAIFI}_{\text{LIMIT}}$	**0.78**	**1.40**	**1.36**	**1.21**	**1.16**	**1.02**	**0.87**

6.4.2 Reason for the proposed quality standard variation

IM 5.4.5(b)

As explained in Sections 6.2 and 6.3 above, it is expected to be some time before our network achieves pre-earthquake reliability performance. This is due to the damage to the network and the increased infrastructure activity expected in Christchurch for the foreseeable future. Accordingly, as part of our CPP proposal we must propose new quality standards which better reflect what we can realistically achieve. The remainder of this section of the CPP proposal sets out how we have derived our proposed quality standards.

6.4.3 Methodology

IM 5.4.5(c) (i)

The CPP IM requires among other things that our CPP proposal contain:

- information supporting different SAIDI and SAIFI limits, and the statistical analysis supporting the derivation of those limits consistent with the DPP method
- an explanation of the reasons for the proposed quality standard
- an engineer’s report on the extent to which the proposed quality standard reflects the realistically achievable performance of the EDB over the CPP regulatory period based on statistical analysis of past SAIDI and SAIFI performance and level of investment provided for.

This section explains the methodology and rationale used to construct our proposed CPP quality standards.

General approach

We propose to retain SAIDI and SAIFI limits for the purpose of specifying quality standards for our CPP.

Our proposed approach is a forecast approach that uses historical data to inform the likely outage frequency, duration and affected consumers on our network for the CPP regulatory period. The approach is consistent with the DPP method, but incorporates the following refinements:

- our current DPP uses a top down approach by using total planned and unplanned (Class B and C) SAIDI and SAIFI from the reference period to determine the quality standards
- we propose a bottom up approach that disaggregates historical data into causes, voltages and regions (and also examining asset categories) in order to determine expected future performance of different parts of the network. The rationale for this is that historical performance is believed to be a reasonable predictor of future

performance for some parts of the network, while it is not believed to be a reasonable predictor of future performance for other parts of the network
- our current DPP uses the FY05-FY09 years as the historical reference period. Our approach uses the more recent FY08-FY12 years as the historical reference period. This is the most recent data available and is consistent with the DPP approach which uses the most recent data available prior to the reset to determine the quality standards. It also provides us with information about the impact of the earthquakes on different parts of our network
- we have also created an alternative historical reference period which comprises the 24 months following the first major earthquake in September 2010 (September 2010 – August 2012). This also provides us with information about the impact of the earthquakes on different parts of our network
- we normalise the data we use, using the DPP method for deriving boundary values, and then applying them to SAIDI on days (MEDs) where the boundary values are exceeded, and SAIFI, on the same day, if the SAIFI boundary values are exceeded. As we have used a bottom up approach, it has been necessary to allocate the boundary value on each MED between the interruptions incurred on each MED
- we have eliminated from the historical reference datasets the outages which were directly attributed to earthquakes. Accordingly our proposed reliability standards include no allowances for future earthquake activity. The CPP may be reopened following a catastrophic event, and should this occur, the quality standards could be reset. The October 2012 estimates from GeoNet[5] predict that within the next 12 months, within the Canterbury aftershock zone,[6] there is a:
  - 71% probability of a magnitude 5 0 – 5.4 earthquake
  - 30% probability of a magnitude 5.5 – 5.9 earthquake
  - 9% probability of a magnitude 6.0 – 6.4 earthquake
  - 3% probability of a magnitude 6.5 – 6.9 earthquake
  - <1% probability of a magnitude 7.0 – 7.9 earthquake.

Source data

Historical outage data for interruptions prior to November 2011 was sourced from our faults database which was manually populated by our System Controllers. Outage data for the interruptions which occurred after November 2011 was sourced from Orion's new Outage Management System, which operates under 'PowerOn', our SCADA Network Management System.

Our proposed approach involves separating historical outage data geographically into two distinct regions, 'urban network' and 'rural network'. Within each of these regions, data is grouped based on voltage, interruption cause and asset class.

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[5] A collaboration between the Institute of Geological and Nuclear Sciences and the Earthquake Commission

[6] Which extends from Hororata in the west to large parts of Banks Peninsula in the east, and from Kaiapoi in the north to Lincoln in the south

We have separated the urban network from the rural network because both sub transmission networks (but in particular the urban 66kV ring) will undergo major planned upgrades over the CPP period to improve network resiliency. In addition, the earthquake consequences are mainly limited to the area supplied by the urban 66kV sub transmission network, where underground cables were damaged from ground movement and liquefaction.

For the purpose of analysing historical data we have grouped the data into causes, by grouping together our standard reporting cause categories, as follows. This data is assessed at 66kV, 33kV and 11kV voltages.

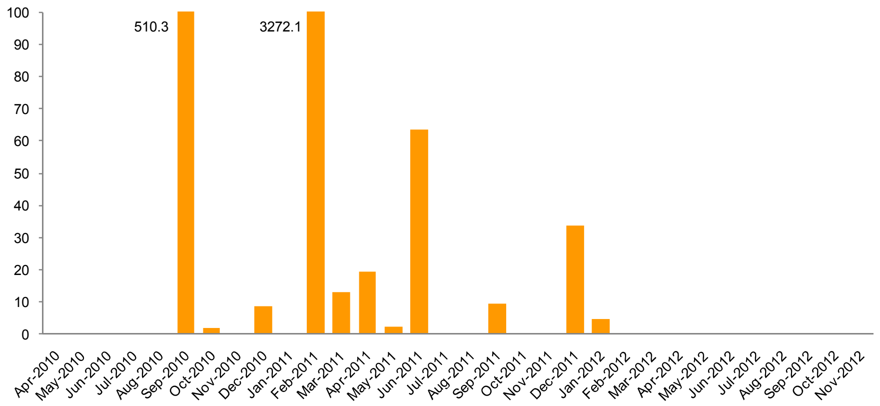
Orion network cause categories	
Analysis cause category	**Orion's cause category**
Planned outage	Programmed outage
Third party damage	Third party damage
External factors (excluding earthquakes)	Bird
	Miscellaneous damage
	Tree
	Weather and environment
	Vehicle collision
	Vermin
	Unknown
Earthquake	Earthquake
System failure	Human error
	Plant failure

We have also analysed the historical outages attributed to Transpower using our cause reporting categories, as follows:

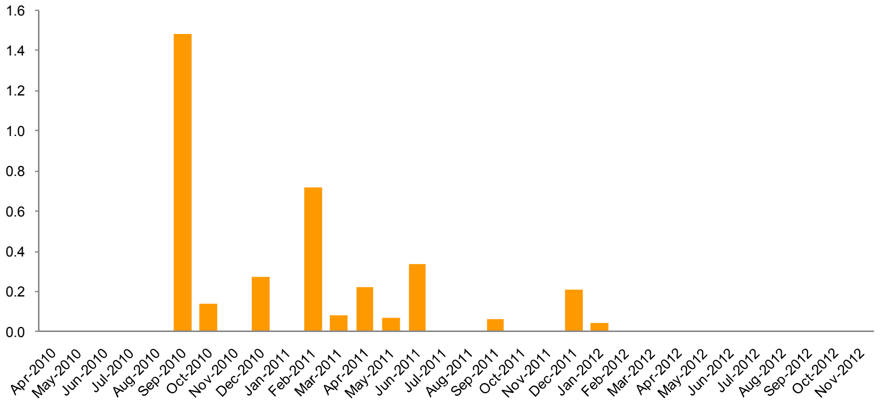
Transpower asset cause categories	
Analysis cause category	**Orion's cause category**
Transpower	Transpower unplanned
Transpower planned	Transpower shutdown
Transpower earthquake	Transpower earthquake

All outages for which the cause and/or commentary were identified as earthquake related have been separated out from the historical reference datasets. There have been no outages directly caused by earthquakes or aftershocks since 12 January 2012 as illustrated in the charts below (which exclude Transpower outages). There are however likely to be interruptions that occur as a result of earthquake damaged assets, for which the cause may not be attributed to earthquakes. For the reasons outlined above, outages caused by the earthquakes have not been included in any of the calculations used to derive the proposed CPP SAIDI and SAIFI limits.

Monthly SAIDI - Earthquakes



Monthly SAIFI - Earthquakes



For the purpose of analysing the pre and post earthquake performance attributed to different parts of the network, we also further disaggregated the historical cause and voltage data, into asset categories. We grouped together outages which were attributed against our standard asset categories as follows:

Asset categories

Analysis asset category	Orion's asset category
Line	Crossarm
	Insulator
	Line
	Pole
Cable	Cable
Other	Fuse
	Kiosk
	Pole switchgear
	Pole transformer
	SCADA
	Switchgear
	Transformer

In order to calculate historical SAIDI and SAIFI we have used the following ICP data.

ICP data	
Year	**Average ICPs for period**
FY05	176,083
FY06	179,130
FY07	181,873
FY08	184,617
FY09	188,158
FY10	191,232
2011 (1 April – 31 August 2010)	192,600
2011 (1 September 2010 – 31 March 2011)	193,133
FY12	191,958
2013 YTD (31 August)	190,136

Methodology applied in deriving the new standards

The general methodology and rationale for deriving the SAIDI and SAIFI attributed to each cause, region and voltage during the CPP period is set out below. We have also described how we have derived the boundary and standard deviation calculations, which have been replicated from the method used in the DPP. Together these methodologies combine to determine the proposed SAIDI and SAIFI limits over the CPP regulatory period.

In this section we have presented data for the relevant historical reference period and the CPP regulatory period. We have also included data for the CPP Assessment Periods (FY13 and FY14) where these are relevant to determining our proposed CPP limits. As noted above, all earthquake related interruptions have been removed from the historical datasets (ie: no allowances are made for earthquake activity during the CPP period).

In the remainder of this section we set out our methods for deriving the CPP Limits by estimating SAIDI and SAIFI attributable to the following cause categories:

Cause categories			
Number	**Cause**	**Sub category**	**Voltage**
I.	Third party damage	a. rural network b. urban network	all voltages 11kV and 33kV only
II.	External factors	a. rural network and urban network	all voltages 11kV and 33kV only
III.	System failure	a. rural network and urban network b. rural network and urban network	11kV only 11kV only 33kV and 66kV only 33kV only

IV.	Planned outages	a. rural network b. urban network	all voltages 11kV and 33kV only
V.	All causes	a. urban network	66kV only
VI.	All causes	a. Transpower assets purchased by Orion	66kV and 33kV

The data presented in the following tables is the raw outage data (ie: before normalisation for MEDs) but excluding all outages directly attributed to the earthquakes.

- **Cause: third party damage**

   a. rural network (all voltages)

The DPP method is used for estimating SAIDI and SAIFI attributed to third party damage in the rural network, to be included in the derivation of the SAIDI and SAIFI CPP limits. This is derived from the FY08-FY12 reference period dataset, being the most recent five year dataset available at this time.

The rationale for this is that interruptions from third party damage are external events that are beyond Orion's control and subject to random variation. As the rural area is not significantly affected by the earthquake-related repairs, historical data is able to be used to derive expected future SAIDI and SAIFI. This is consistent with the no material deterioration principle which underpins how the DPP limits were set. It is also consistent with consumer expectations for network performance to be restored to historical levels.

The result of applying this method to SAIDI is illustrated below. This shows the historical average of 1.5 SAIDI minutes extrapolated throughout the CPP period.

3rd party damage - Rural (all voltages) - Before normalisation - SAIDI							CPP period				
	FY08	FY09	FY10	FY11	FY12	FY14	FY15	FY16	FY17	FY18	FY19
11kV	1.1	0.9	1.9	1.8	1.5	1.4	1.4	1.4	1.4	1.4	1.4
33kV	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
66kV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**1.1**	**1.0**	**1.9**	**1.8**	**1.5**	**1.5**	**1.5**	**1.5**	**1.5**	**1.5**	**1.5**

The result of applying this method to SAIFI is illustrated below. This shows the historical average of 0.02 interruptions extrapolated throughout the CPP period.

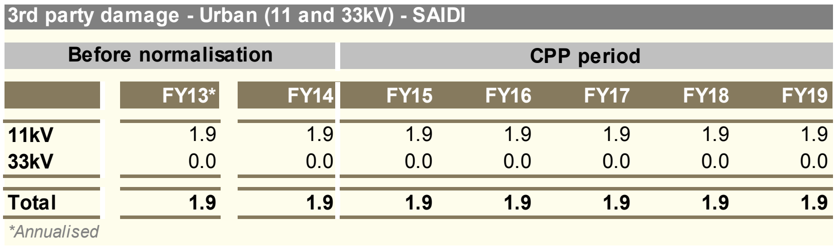
3rd party damage - Rural (all voltages) - Before normalisation - SAIFI							CPP period				
	FY08	FY09	FY10	FY11	FY12	FY14	FY15	FY16	FY17	FY18	FY19
11kV	0.02	0.01	0.02	0.03	0.01	0.02	0.02	0.02	0.02	0.02	0.02
33kV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
66kV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.02**	**0.02**	**0.02**	**0.03**	**0.01**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**

   b. urban network (11kV and 33kV)

In the urban network, we expect an increased level of work by third parties involved in rebuilding Christchurch, in particular SCIRT and other contractors. This is expected to manifest itself in increased interruptions from third party damage from 1 January 2012[7] continuing throughout the CPP period. The method used to estimate SAIDI and SAIFI attributed to third party damage in the urban network is based on annualised data for the period: 1 January 2012 – 31 August 2012. This figure is assumed to apply for the entire CPP period.[8]

This estimate does expose us to some risk that the speed and intensity of rebuild activities (which are influenced by external agencies) are greater than current levels. If the intensity of the rebuild increases significantly above current levels, it is expected to result in increased SAIDI and SAIFI attributable to third parties.

The result of applying this method to SAIDI is illustrated below. This shows the annualised FY13 SAIDI minutes of 1.9 extrapolated throughout the CPP regulatory period.

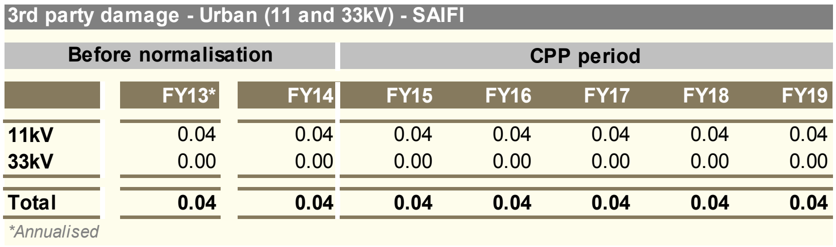


3rd party damage - Urban (11 and 33kV) - SAIDI

Before normalisation			CPP period				
	FY13*	FY14	FY15	FY16	FY17	FY18	FY19
11kV	1.9	1.9	1.9	1.9	1.9	1.9	1.9
33kV	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**1.9**	**1.9**	**1.9**	**1.9**	**1.9**	**1.9**	**1.9**

**Annualised*

The result of applying this method to SAIFI is illustrated below. This shows the annualised FY13 SAIFI of 0.04 interruptions extrapolated throughout the CPP regulatory period.



3rd party damage - Urban (11 and 33kV) - SAIFI

Before normalisation			CPP period				
	FY13*	FY14	FY15	FY16	FY17	FY18	FY19
11kV	0.04	0.04	0.04	0.04	0.04	0.04	0.04
33kV	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**

**Annualised*

- **Cause: External factors**

Historically, external factors have been the largest cause of interruptions on our network. As stated above, before estimating SAIDI and SAIFI attributable to external causes, all earthquake related interruptions were removed from the historical dataset.

a. rural network (all voltages) and urban network (11kV and 33kV)

Our rural network is predominantly overhead, so it is exposed to interruptions from environmental conditions including extreme weather (such as snow and high winds). The DPP method is used for estimating SAIDI and SAIFI to be attributed to external

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[7] SCIRT released their SCIRP (Stronger Christchurch Infrastructure Rebuild Plan) in December 2011. This document outlines SCIRT's plans to rebuild Christchurch's damaged infrastructure from 2012 onwards.

[8] CERA's Recovery Strategy for Greater Christchurch (May 2012), project recovery works beyond 2019 suggesting heightened third party interruptions can be expected at least to the end of the CPP period.

factors in the derivation of the SAIDI and SAIFI limits. This is derived using the same method outlined above for the rural network third party damage, ie: it uses historical averages derived from the FY08-FY12 reference dataset. This approach is reasonable for external factors because they are beyond Orion's control, are subject to random variation and are not affected by earthquake consequences.

The result of applying this method to SAIDI is illustrated below. This shows that the historical average 17.9 SAIDI minutes (rural) and 6.7 SAIDI minutes (urban) is extrapolated throughout the CPP period.

External factors - Rural (all voltages) - Before normalisation - SAIDI							CPP period				
	FY08	FY09	FY10	FY11	FY12	FY14	FY15	FY16	FY17	FY18	FY19
11kV	10.9	13.0	8.8	16.0	23.0	14.3	14.3	14.3	14.3	14.3	14.3
33kV	3.0	1.9	1.5	9.4	1.5	3.4	3.4	3.4	3.4	3.4	3.4
66kV	0.0	0.1	0.0	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**13.9**	**15.0**	**10.3**	**25.6**	**24.6**	**17.9**	**17.9**	**17.9**	**17.9**	**17.9**	**17.9**

External Factors - Urban (11 and 33kV) - Before Normalisation - SAIDI							CPP Period				
	FY08	FY09	FY10	FY11	FY12	FY14	FY15	FY16	FY17	FY18	FY19
11kV	3.9	4.2	5.3	7.1	13.1	6.7	6.7	6.7	6.7	6.7	6.7
33kV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**3.9**	**4.2**	**5.3**	**7.1**	**13.1**	**6.7**	**6.7**	**6.7**	**6.7**	**6.7**	**6.7**

The result of applying this method to SAIFI is illustrated below. This shows that the historical average 0.18 interruptions (rural) and 0.07 interruptions (urban) is extrapolated throughout the CPP period.

External factors - Rural (all voltages) - Before normalisation - SAIFI							CPP period				
	FY08	FY09	FY10	FY11	FY12	FY14	FY15	FY16	FY17	FY18	FY19
11kV	0.11	0.12	0.11	0.15	0.20	0.14	0.14	0.14	0.14	0.14	0.14
33kV	0.06	0.03	0.02	0.06	0.02	0.04	0.04	0.04	0.04	0.04	0.04
66kV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.17**	**0.15**	**0.13**	**0.21**	**0.22**	**0.18**	**0.18**	**0.18**	**0.18**	**0.18**	**0.18**

External Factors - Urban (11 and 33kV) - Before Normalisation - SAIFI							CPP Period				
-	FY08	FY09	FY10	FY11	FY12	FY14	FY15	FY16	FY17	FY18	FY19
11kV	0.06	0.05	0.06	0.08	0.10	0.07	0.07	0.07	0.07	0.07	0.07
33kV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.06**	**0.05**	**0.06**	**0.08**	**0.10**	**0.07**	**0.07**	**0.07**	**0.07**	**0.07**	**0.07**

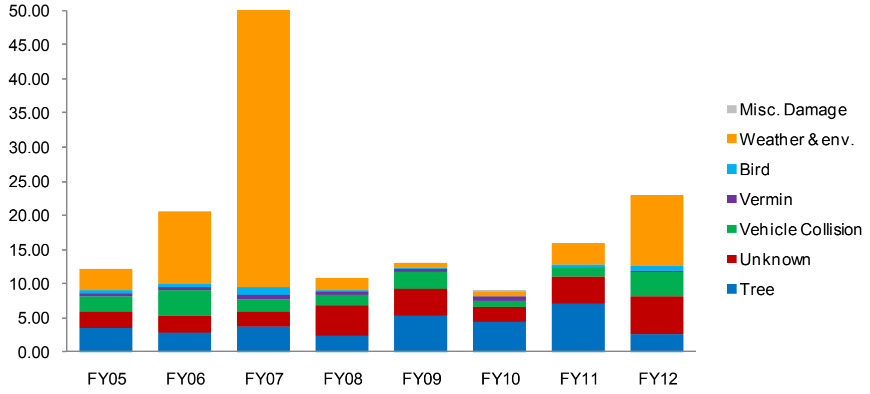
Further consideration of external causes post earthquakes

In order to confirm our approach we examined the year on year variability in SAIDI and SAIFI by considering the underlying causes. In some cases post earthquake data was higher due to snow storms (FY12 and FY13) and increased tree interference due to high winds in FY11. This analysis suggests that the estimating approach is valid. The MED normalisation tends to apply on the days affected by major snow and extreme high winds.

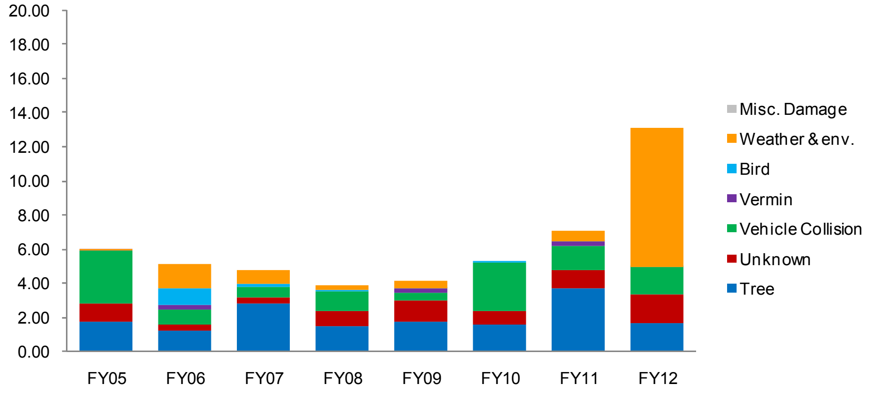
We also note that while high winds and snow storms are not uncommon in Canterbury, and parts of the network are designed to accommodate snow loading, the network is not designed to withstand severe snow storms or high winds.

SAIDI minutes caused by external factors are those which are largely beyond Orion's control, thus we would expect variation over time. In some cases the post earthquake interruption data appears different in comparison to the pre-earthquake performance. This data has not been normalised for extreme events.

External factors - Rural (11kV) - SAIDI

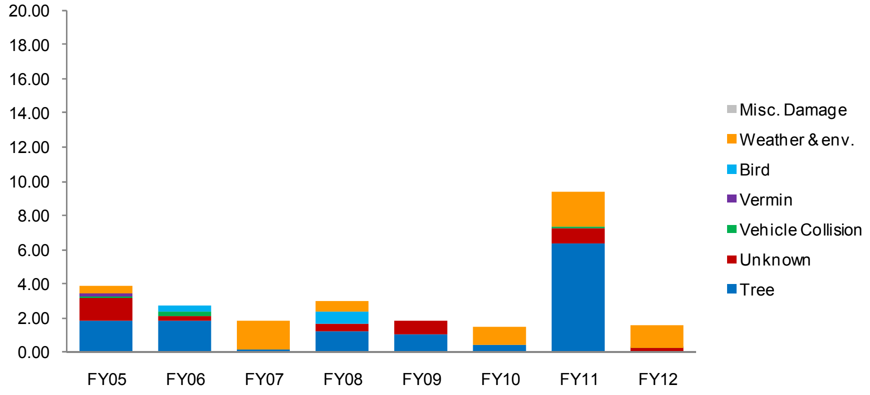


External factors - Urban (11kV) - SAIDI

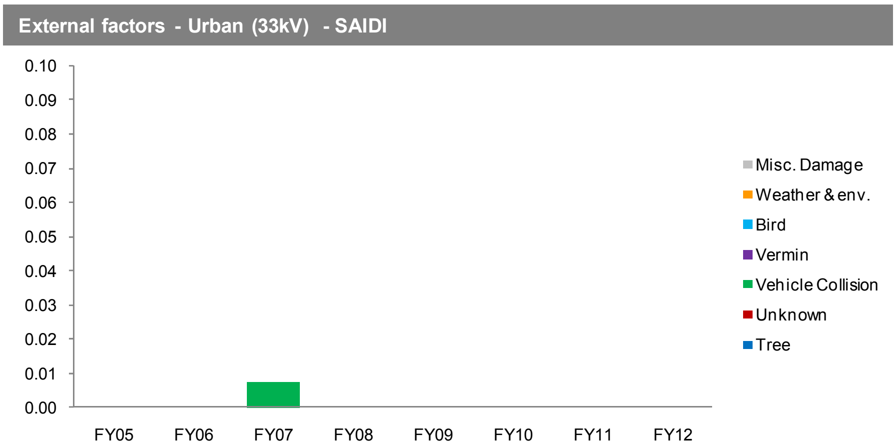


The charts above illustrate an increase in rural and urban 11kV SAIDI post-earthquake. We have examined the data but cannot establish a causal relationship between the earthquakes and the increase in these outages (which are predominantly associated with tree/weather/unknown causes). We are aware of wind and snow storms which occurred during the post earthquake period, the impacts of which are reflected in the results.

External factors - Rural (33kV) - SAIDI



The chart above shows an increase in rural 33kV SAIDI minutes post-earthquake which is similar to the 11kV trend. This increase was predominantly caused by factors (such as trees and weather) which are believed to be independent of the earthquakes.



The chart above shows that urban 33kV SAIDI minutes are extremely low and there is no post-earthquake impact.

This analysis confirms the expected variability in the sources of the outages caused by external events in our rural and urban networks. There is no discernable trend from the data available that suggests the earthquakes have influenced the frequency or duration of outages to be expected from external events. Accordingly we have concluded that our estimation approach (based on extrapolation of historical data) is valid for this source of outages.

- **Cause: System Failure**
  a. *Rural (11kV) and Urban (11kV)*

Orion's rural and urban 11kV network assets have been subject to damage from earthquakes, not all of which has manifested itself to date. We are uncertain as to the condition of many of our underground assets, particularly urban 11kV cables. In addition, post-earthquake reconstruction and relocation has changed load distribution across the network and assets. Rural and urban 11kV network performance is therefore different to what it was before the earthquakes occurred. Accordingly it is not appropriate to use pre-earthquake historical data for estimating SAIDI and SAIFI attributable to system failure for these assets.

Over time, assets will be tested and any residual deficiencies discovered and repaired. This will occur through normal repairs, replacements, inspections, network improvements and interruption response.

To account for the expected improvement in network resilience, it is assumed that the SAIDI and SAIFI attributed to system failure will decrease linearly over the CPP period.

This assumes the starting position is derived from the 24 month post-earthquake historical average, with annual improvements over the CPP period to achieve a pre-earthquake historical average equivalent to the current DPP (ie: using the DPP reference dataset for FY05-FY09). This is consistent with our plan to complete our post earthquake 11kV asset testing programme over a period of five years and address issues arising from that programme through our maintenance and replacement programmes within the CPP period.

A linear decrease is chosen as it balances benefits between Orion and consumers. It is not possible to move immediately to a pre earthquake position for the reasons outlined above. However, consumers will benefit from improved performance throughout the CPP period as our network maintenance and replacement programme progresses. In the absence of complete information about the condition of the network post earthquake and the probability of failure, we believe that it is not possible to determine a more accurate method at this time.

The result of applying this method to SAIDI is illustrated below. This shows a starting point in FY14 of the post earthquake average SAIDI of 12.7 minutes (rural) and 20.0 SAIDI minutes (urban), reducing linearly to 7.6 minutes (rural) and 7.2 minutes (urban) in FY19.

System failure - Rural (11kV) - SAIDI

Before normalisation			CPP period				
	post earthquake average	FY14	FY15	FY16	FY17	FY18	FY19
11kV	12.7	12.7	11.7	10.7	9.7	8.6	7.6

System failure - Urban (11kV) - SAIDI

Before normalisation			CPP period				
	post earthquake average	FY14	FY15	FY16	FY17	FY18	FY19
11kV	20.0	20.0	17.4	14.9	12.3	9.8	7.2

The starting point in FY14 of the post earthquake average SAIFI of 0.14 interruptions (rural) and 0.38 interruptions (urban), reduces linearly to 0.10 interruptions (rural) and 0.13 interruptions (urban) in FY19.

System failure - Rural (11kV) - SAIFI

Before normalisation			CPP period				
	post earthquake average	FY14	FY15	FY16	FY17	FY18	FY19
11kV	0.14	0.14	0.13	0.12	0.11	0.10	0.10

System failure - Urban (11kV) - SAIFI

Before normalisation			CPP period				
-	post earthquake average	FY14	FY15	FY16	FY17	FY18	FY19
11kV	0.38	0.38	0.33	0.28	0.23	0.18	0.13

b. rural (33kV and 66kV) and urban (33kV)

There is no evidence to suggest that the post earthquake performance of the rural 33kV and 66kV and urban 33kV assets attributable to system failure is likely to be different to the pre earthquake performance (e.g. the 33kV urban network assets are located in the west of the urban area which was relatively unaffected by the earthquakes). Accordingly the DPP method is used for estimating SAIDI and SAIFI attributed to system failure for these assets. This is derived from the FY08-FY12 reference period dataset, being the most recent five year dataset available at this time.

The result of applying this method to SAIDI is illustrated below. The historical average SAIDI of 2.1 minutes is extrapolated throughout the CPP period. This applies to rural assets only, as no system failure outages were recorded for urban 33kV during the historical period.

System failure - Rural (33 and 66kV) - Before normalisation - SAIDI							CPP period				
	FY08	FY09	FY10	FY11	FY12	FY14	FY15	FY16	FY17	FY18	FY19
33kV	3.7	3.3	2.2	1.2	0.2	2.1	2.1	2.1	2.1	2.1	2.1
66kV	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**3.7**	**3.4**	**2.2**	**1.2**	**0.2**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**

System failure - Urban (33kV) - Before normalisation - SAIDI							CPP period				
	FY08	FY09	FY10	FY11	FY12	FY14	FY15	FY16	FY17	FY18	FY19
33kV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

The result of applying this method to SAIFI is illustrated below. The historical average SAIFI of 0.05 interruptions is extrapolated throughout the CPP period. As above, this applies to rural assets only.

System failure - Rural (33 and 66kV) - Before normalisation - SAIFI							CPP period				
	FY08	FY09	FY10	FY11	FY12	FY14	FY15	FY16	FY17	FY18	FY19
33kV	0.10	0.06	0.04	0.03	0.00	0.05	0.05	0.05	0.05	0.05	0.05
66kV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.10**	**0.06**	**0.04**	**0.03**	**0.00**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**

System failure - Urban (33kV) - Before normalisation - SAIFI							CPP period				
	FY08	FY09	FY10	FY11	FY12	FY14	FY15	FY16	FY17	FY18	FY19
33kV	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

- **Cause: Planned Outage**

  a. rural (All Voltages)

The DPP method is used for estimating the SAIDI and SAIFI attributed to planned outages for all rural assets. As the post earthquake rebuild activity, which will have an impact on planned outages, is primarily concentrated in the urban network, historical (pre-earthquake) data is relevant for the rural network. Accordingly a historical average derived from the FY08-FY12 reference data is used.

The result of applying this method to SAIDI is illustrated below. This shows the historical average of 11.8 SAIDI minutes is extrapolated throughout the CPP period.

Planned outages - Rural (all voltages) - Before normalisation - SAIDI							CPP period				
	FY08	FY09	FY10	FY11	FY12	FY14	FY15	FY16	FY17	FY18	FY19
11kV	8.7	17.9	19.5	5.0	7.8	11.8	11.8	11.8	11.8	11.8	11.8
33kV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
66kV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**8.7**	**17.9**	**19.5**	**5.0**	**7.8**	**11.8**	**11.8**	**11.8**	**11.8**	**11.8**	**11.8**

The result of applying this method to SAIFI is illustrated below. This shows the historical average of 0.05 interruptions is extrapolated throughout the CPP period.

Planned outages - Rural (all voltages) - Before normalisation - SAIFI							CPP period				
	FY08	FY09	FY10	FY11	FY12	FY14	FY15	FY16	FY17	FY18	FY19
11kV	0.03	0.06	0.08	0.03	0.03	0.05	0.05	0.05	0.05	0.05	0.05
33kV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
66kV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.03**	**0.06**	**0.08**	**0.03**	**0.03**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**

b. *urban (11kV and 33kV)*

Orion is exposed to the risk that the speed and intensity of rebuild activities require a greater number of planned outages than current levels. This is expected to result in increased SAIDI and SAIFI attributable to planned outages.

The number and duration of planned outages in the urban network is expected to be partly influenced by requests of external agencies, such as CERA and SCIRT, as the Christchurch rebuild progresses. It is extremely difficult to predict this demand. However, Orion will attempt to accommodate the needs of others within its planned work programme and where possible prioritise to facilitate the requirements of others.

In addition Orion's planned cable testing programme will affect urban assets. This is not expected to result in a significant increase in planned outages as the network will be switched around to provide alternative feeds where possible while testing is taking place. Where no alternative feed exists, LV ties or generators are expected to be able to be used to minimise disruption to consumers.

Our draft CPP proposal, which formed the basis of our consultation with consumers, and which was subject to independent engineering review, proposed a constant level of planned outages for the urban network based on historical data. On reflection, and consistent with feedback from Linetech Consulting (their report is included as Appendix 3) we have revised our approach to this component of our proposed method. This is the only change we have made in response to the engineering review.

Given the Christchurch redevelopment phase has only just commenced, we do not believe that it is appropriate to limit urban planned outages to historical levels during the CPP period. As CERA's recovery plans extend beyond the end of the CPP period we believe that additional allowances for planned outages must be provided for until FY19. We do not have information which would allow us to forecast the likely level of planned outages to occur over the CPP regulatory period. Thus, in the absence of a better alternative, and consistent with Linetech's report, we have doubled the historical averages of 1.9 SAIDI minutes and 0.01 interruptions derived from the FY08-FY12 datasets for urban 11kV and 33kV planned outages.

The result of applying this method to SAIDI is illustrated below with an allowance of 3.7 SAIDI minutes attributed to urban 33kV and 11kV planned outages throughout the CPP period.

Planned outage - Urban (11 and 33kV) - Before normalisation - SAIDI							CPP period				
	FY08	FY09	FY10	FY11	FY12	FY14	FY15	FY16	FY17	FY18	FY19
11kV	1.5	3.3	1.3	1.2	2.2	3.7	3.7	3.7	3.7	3.7	3.7
33kV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**1.5**	**3.3**	**1.3**	**1.2**	**2.2**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**

The result of applying this method to SAIFI is illustrated below. This shows 0.2 interruptions attributed to urban 11kV and 33kV SAIFI throughout the CPP regulatory period.

Planned outage - Urban (11 and 33kV) - Before normalisation - SAIFI							CPP period				
	FY08	FY09	FY10	FY11	FY12	FY14	FY15	FY16	FY17	FY18	FY19
11kV	0.01	0.02	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02
33kV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.01**	**0.02**	**0.01**	**0.01**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**

- **Cause: Urban 66kV network (all causes)**

The September 2010 and February 2011 earthquakes severely damaged parts of the Orion 66kV subtransmission network. The damage from the earthquakes resulted in the following four circuits being retired:

- Bromley to Dallington #1
- Bromley to Dallington #2
- Bromley to Pages/Brighton #1
- Bromley to Pages/Brighton #2

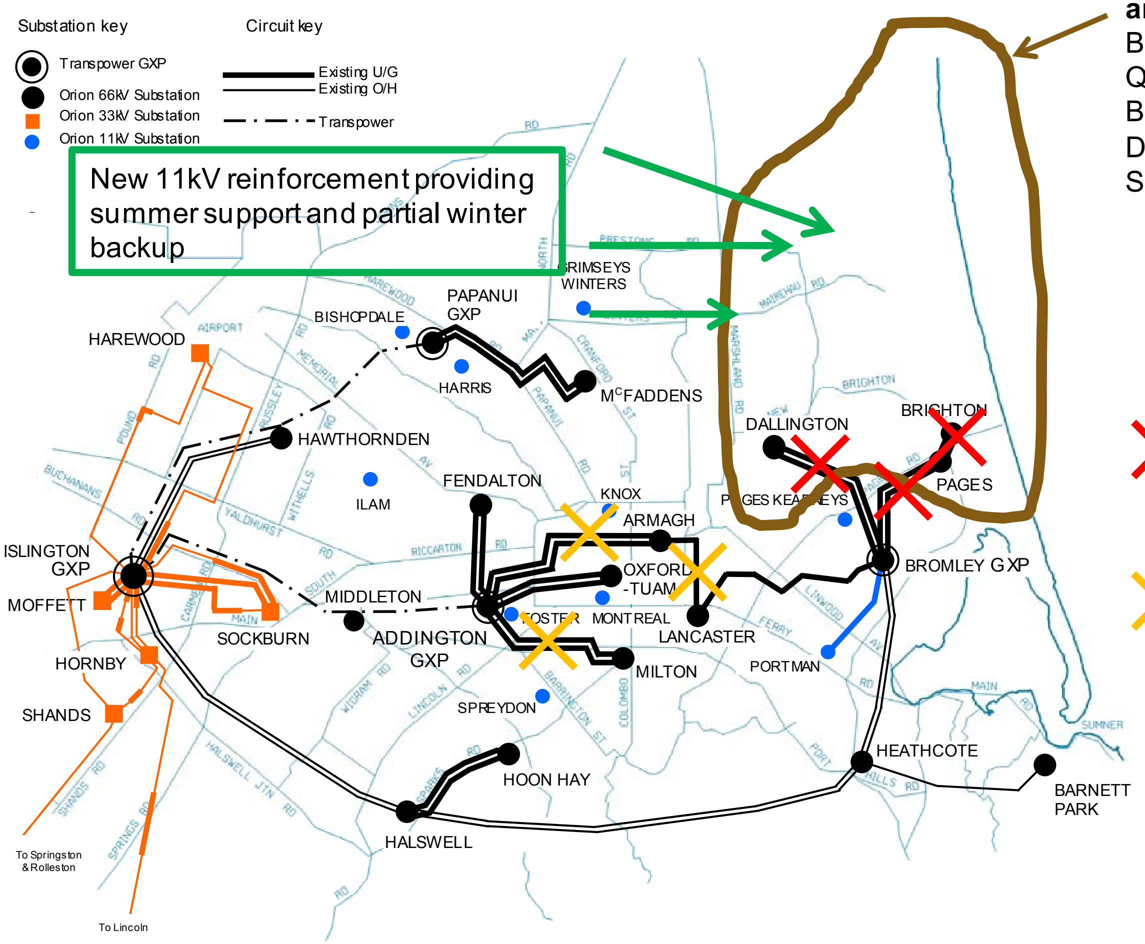
In addition, the following circuits sustained damage requiring the insertion of new sections of cable and/or through-jointing at points of damage:

- Addington to Armagh #1
- Addington to Armagh #2
- Lancaster to Armagh
- Addington to Milton #1 (third party contractor damage)
- Addington to Milton #2 (third party contractor damage)

The map included immediately overleaf illustrates the retired and damaged urban 66kV circuits.

To increase resiliency (through route diversity) and to provide additional capacity for expected growth in northern Christchurch, Orion have elected not to replace the retired 66kV cables in a ‘like for like’ manner, but to develop a new urban 66kV configuration of these assets. The new configuration is illustrated on the second map on the following pages.

Urban subtransmission network 66 & 33kV



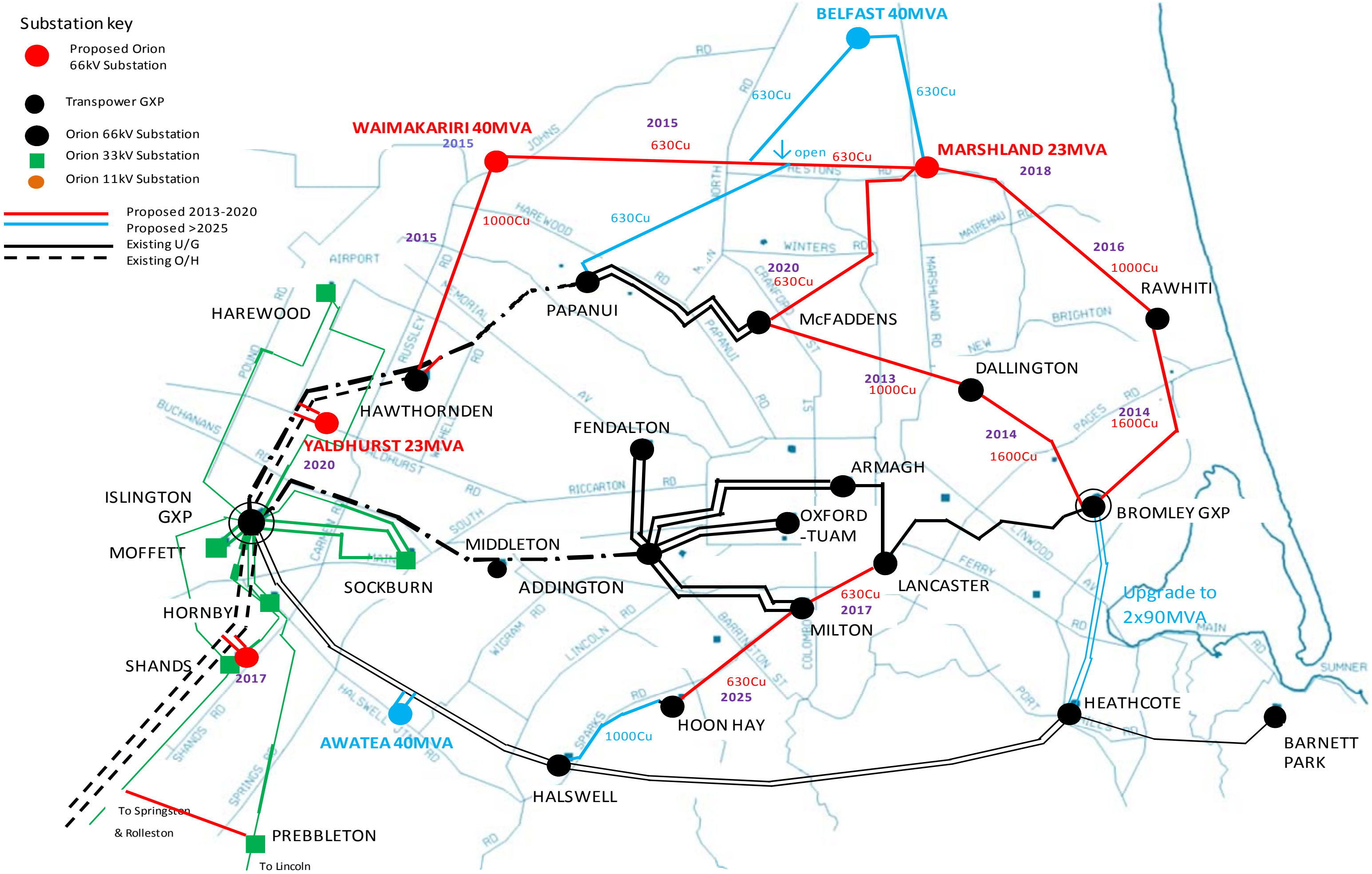
New 11kV reinforcement providing summer support and partial winter backup

Area normally supplied by Dallington and Brighton zone substations:
Brooklands, Spencerville, Marshlands, Queenspark, Parklands, Waimairi Beach, Burwood, Westhaven, Shirley, Dallington, New Brighton, Bexley and South New Brighton

✕ Denotes major cable retirement

✕ Denotes cable failure where repairs were required

Planned new urban sub transmission network configuration



The reliability of the existing and new sub transmission network is vulnerable in two ways:

- increased failure rate due to earthquake damage
- reliability performance during the staged 66kV rebuild.

The method applied to estimating the SAIDI and SAIFI attributed to the urban 66kV network comprises the following three elements:

i) Pre-earthquake (baseline) urban 66kV network reliability

The DPP method is used to estimate a base level of SAIDI and SAIFI attributed to the urban 66kV network using a historical average of all categories (third party damage, external factors, planned outages and system failure) of urban 66kV outages. This is derived from the pre-earthquake FY05-FY09 reference data.

ii) Allowance for the area of the urban 66kV network that is not subject to the staged 66kV rebuild, but is vulnerable to an increased failure rate due to earthquake damage

An additional estimate of SAIDI and SAIFI to be attributed to the parts of the urban 66kV network not subject to the staged 66kV rebuild is made. This is based on an expected number of annual interruptions and the maximum calculated impact of an event on SAIDI and SAIFI (based on average restoration times from our Security of Supply standards and the maximum number of consumers impacted by an interruption).

Approximately 66% of Orion's sub transmission network falls into this category. Many of these circuits have sustained damage, and many have more through-joints than before the earthquakes. This increases the likelihood of failure as joints are not as reliable as the body of the cable.

Cable testing undertaken by Wire Scan in March 2011 on some of the 66kV circuits identified 13 areas of impedance change (i.e. potential cable failures) over 8 66kV cables (the report is set out in Appendix 8). Excavation around the areas of 'impedance change' did not show any visible external damage to the encasing concrete. As further investigation would require serious intrusion, we have not been able to confirm or repair the potential faults, leaving the network susceptible to interruptions.

There are also likely to be other faults beyond those indicated by the Wire Scan tests. For example one of the Addington to Armagh cables failed in a location that was not detected as having an 'impedance change'. We are currently undertaking a programme of partial discharge tests that are expected to identify further areas of cable damage.

The Bromley GXP to Lancaster zone substation cable illustrates the vulnerability of the existing network. The cable route passes through neighbourhoods that were severely damaged in the earthquake. Although this cable did not fail during any of the earthquakes it is highly unlikely that this cable is not damaged in some way. Were the Bromley to Lancaster circuit to fail, then the Lancaster zone substation would be without power while 66kV switching takes place.

As previously noted, the increased level of utility works occurring in the public berm and roadways leads to a heightened risk of third party damage, e.g. a contractor recently severed the two Addington to Milton 66kV circuits resulting in 0.275 SAIDI minutes.

Based on these factors, it is appropriate to assume that the failure rate of the existing 66kV cables will be higher than normal over the CPP period. Over time the 66kV assets will be tested and any residual deficiencies discovered and repaired. To account for the expected improvement in network resilience, it is assumed that the SAIDI and SAIFI attributed to the 66kV sub transmission network will decrease over the CPP period. In estimating the failure rate of the existing sub transmission network we have used our best judgement consistent with a prudent reliability scenario, to determine the estimates which are summarised in the following table.

SAIDI and SAIFI impacts of interruptions on 66kV urban network not subject to upgrades

	FY14	FY15	FY16	FY17	FY18	FY19
Increase in subtransmission events causing an outage to customers	2	2	1	1	0	0
Impact to SAIDI (minutes)	**8.9**	**9.0**	**4.4**	**4.4**	**0.0**	**0.0**
Impact to SAIFI	**0.15**	**0.15**	**0.07**	**0.07**	**0.00**	**0.00**

The impact on SAIDI and SAIFI from a sub transmission failure has been based on the maximum calculated impact (reflecting the average restoration times set out in our Security of Supply standard and the maximum number of consumers impacted by an interruption). These assumptions are outlined in more detail in the following section.

iii) Allowance for the areas of the urban 66kV network that are subject to the staged 66kV rebuild

An additional estimate of the SAIDI and SAIFI attributed to the parts of the urban 66kV network that are subject to the staged 66kV rebuild were determined by modelling the network configuration for each year of the CPP period.

The rebuild of the east Christchurch 66kV network and the upgrade of this network to meet new load growth is a multi-year programme that lasts for the duration of the CPP period. Until the network is returned to a N-1 security standard, it is estimated that the SAIDI and SAIFI attributed to this area will be greater than pre-earthquake levels.

SAIDI and SAIFI impacts are based on an expected number of annual interruptions and the maximum calculated impact of a 66kV event on SAIDI and SAIFI (based on average restoration times using 11kV switching for zone substation outages[9] and the number of ICPs affected by the outage).

The table below summarises the expected performance of the sub transmission network for the north (N) and east (E) Christchurch areas, and demonstrates the significant impact on reliability from a single outage on the 66kV network when 11kV switching is used to restore supply.

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[9] Restoration of supply was modelled to occur by either an alternative 66kV supply or use of the 11kV network. Restoration times were assumed to be 5 minutes and 60 minutes respectively (based on our Security of Supply standards).

Calculation of SAIDI and SAIFI impact on urban 66kV network

	FY14	FY15	FY16	FY17	FY18	FY19
Number of connections (N & E)	64,752	65,581	66,290	66,620	67,154	67,882
Change in SAIDI of N & E	2.96	1.97	3.21	2.00	2.40	1.08
Change in SAIFI of N & E	0.1	0.1	0.1	0.1	0.1	0.1
N & E % of total connections	34%	34%	34%	34%	34%	34%
Potential single event impact to Network wide SAIDI	**4.44**	**4.50**	**4.38**	**4.37**	**4.37**	**4.08**
Potential single event impact to Network wide SAIFI	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**

The increased volume of work associated with the rebuild and upgrade of the northern and eastern parts of the network, is expected to increase the number of unplanned outages. These could occur due to commissioning testing and the reduced level of security of supply when new assets are integrated into the network. In estimating the failure rate of the northern and eastern sub transmission network subject to rebuild and upgrade, we have used our judgement to determine a prudent reliability scenario, in order to derive the following estimates.

SAIDI and SAIFI impacts of interruptions on 66kV urban network subject to upgrades

	FY14	FY15	FY16	FY17	FY18	FY19
Increase in subtransmission events caused by reduced security of supply during construction and commissioning	1	1	1	1	1	0
Increase in subtransmission events caused by staged 66kV rebuild	1	1	1	1	1	1
Impact to SAIDI (minutes)	**8.9**	**9.0**	**8.8**	**8.7**	**8.7**	**4.1**
Impact to SAIFI	**0.15**	**0.15**	**0.15**	**0.15**	**0.15**	**0.07**

The result of applying this method to SAIDI is illustrated below. This shows that the baseline allowance is just 0.3 SAIDI minutes for urban 66kV. At the beginning of the CPP period, four outages per annum are provided for (comprising two for the area not affected by upgrades and two for the upgrade area). A total of 18 SAIDI minutes are attributed to these outages. The number of expected outages is forecast to reduce significantly as the resilience of the 66kV urban network is restored, and by FY19 just one outage is predicted, contributing 4.1 SAIDI minutes to the proposed allowance.

All causes - Urban (66kV) - Before normalisation - SAIDI

	FY05	FY06	FY07	FY08	FY09	FY14	FY15	FY16	FY17	FY18	FY19
Baseline 66kV urban	0.6	0.5	0.0	0.3	0.0	0.3	0.3	0.3	0.3	0.3	0.3
Not subject to 66kV urban upgrades						8.9	9.0	4.4	4.4	0.0	0.0
Subject to 66kV urban upgrades						8.9	9.0	8.8	8.7	8.7	4.1
Total	**0.6**	**0.5**	**0.0**	**0.3**	**0.0**	**18.0**	**18.2**	**13.4**	**13.4**	**9.0**	**4.3**

The result of applying this method to SAIFI is illustrated below. This shows a similar trend to SAIDI. A baseline allowance of 0.03 SAIFI is provided throughout the CPP period. The four additional outages predicted in FY15 contribute an additional 0.3 SAIFI. This reduces to 0.07 SAIFI by FY19, attributed to the one outage predicted on the urban 66kV, as the urban 66kV subtransmission reconfiguration nears completion.

All causes - Urban (66kV) - Before normalisation - SAIFI

	FY05	FY06	FY07	FY08	FY09	FY14	FY15	FY16	FY17	FY18	FY19
Baseline 66kV urban	0.03	0.07	0.00	0.04	0.00	0.03	0.03	0.03	0.03	0.03	0.03
Not subject to 66kV urban upgrades						0.15	0.15	0.07	0.07	0.00	0.00
Subject to 66kV urban upgrades						0.15	0.15	0.15	0.15	0.15	0.07
Total	**0.03**	**0.07**	**0.00**	**0.04**	**0.00**	**0.32**	**0.33**	**0.25**	**0.25**	**0.17**	**0.10**

- **Cause: Outages originating in Transpower assets purchased by Orion**

Orion has recently purchased, and is planning further purchases, of a number of spur assets owned by Transpower (Papanui spur assets were purchased on 1 August 2012). Similar to the provisions in the DPP quality standard, adjustments are made to accommodate the transfer of ownership and hence responsibility for asset performance to Orion.

While the DPP method permits retrospective adjustment to the DPP limit after the assets have been purchased, it is necessary for us to predict the impact of the new assets in advance, for the purpose of the CPP limits. These adjustments are made at the relevant points in time that the asset transfers are forecast to occur consistent with the wider urban sub transmission system upgrade.

The DPP method is used for determining the SAIDI and SAIFI ascribed to each of the spur assets transferred, from the year of transfer. The historical performance of each spur asset derived from the FY08-FY12 reference dataset is used for this purpose. As for Orion's network assets, all earthquake related interruptions are removed from the historical dataset. The averages for each asset are applied from the beginning of the year following the purchase (as purchase dates are planned for 31 March each year)[10] and applied for all subsequent years in the CPP period.

Planned asset purchase from Transpower

Assets	Year of purchase
Papanui (66kV assets)	FY13
Springston (66kV assets)	FY14
Addington (66kV assets)	FY15
Middleton (66kV assets)	FY15
Arthurs Pass (66kV assets)	FY15
Castle Hill (66kV assets)	FY15
Hororata (66kV assets)	FY16
Bromley (66kV and 11kV assets)	FY16
Islington (33kV assets)	FY17

The result of applying this method to SAIDI is illustrated below. Most of the Transpower spur assets to be purchased have little history of outages in the FY08-FY12 dataset. However, as the assets are progressively transferred to Orion throughout the CPP period, the SAIDI allowance increases from 2.8 minutes in FY15 to 3.0 minutes in FY19. The majority of this is attributable to Springston (2.8 minutes) from FY15 onwards.

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[10] The exception is Papanui which was transferred in FY13. Papanui has no outages recorded in the historical period, hence we have included no allowances for future outages during the CPP period.

Transpower asset purchases - Before normalisation - SAIDI							CPP period				
	FY08	FY09	FY10	FY11	FY12	FY14	FY15	FY16	FY17	FY18	FY19
Papanui (66kV assets)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Springston (66kV assets)	5.9	0.0	7.9	0.1	0.1	1.9	2.8	2.8	2.8	2.8	2.8
Addington (66kV assets)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Middleton (66kV assets)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Arthurs Pass (66kV assets)	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Castle Hill (66kV assets)	0.1	0.0	0.0	0.3	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Hororata (66kV assets)	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
Bromley (66kV and 11kV assets)	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
Islington (33kV assets)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**6.0**	**0.7**	**7.9**	**0.4**	**0.1**	**1.9**	**2.8**	**2.9**	**3.0**	**3.0**	**3.0**

The result of applying this method to SAIFI is illustrated below. The SAIFI allowance increases from 0.04 in FY15 to 0.06 in FY19 as the assets are progressively transferred to Orion. As for SAIDI, the majority are attributable to Springston.

Transpower asset purchases - Before normalisation - SAIFI							CPP period				
	FY08	FY09	FY10	FY11	FY12	FY14	FY15	FY16	FY17	FY18	FY19
Papanui (66kV assets)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Springston (66kV assets)	0.09	0.00	0.09	0.01	0.01	0.03	0.04	0.04	0.04	0.04	0.04
Addington (66kV assets)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Middleton (66kV assets)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Arthurs Pass (66kV assets)	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Castle Hill (66kV assets)	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hororata (66kV assets)	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bromley (66kV and 11kV assets)	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Islington (33kV assets)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.10**	**0.08**	**0.09**	**0.01**	**0.01**	**0.03**	**0.04**	**0.04**	**0.06**	**0.06**	**0.06**

Summary of SAIDI and SAIFI by cause (before normalisation)

The following tables summarise the SAIDI and SAFI attributed to each cause during the CPP period for the purpose of deriving the CPP limits, using our bottom up method described above. This data is presented before normalisation. SAIDI minutes reduce from 95.7 minutes in FY15 to 67.8 minutes in FY19. By way of comparison the historical average for the FY08-FY12 period (excluding earthquake outages) is 69.2 SAIDI minutes. The historical average for the FY05-FY09 period (used to establish the DPP quality standards) is 75.7 SAIDI minutes. This prior period is particularly high due to the impact of the 2007 snow storms.

SAIDI - Before Normalisation	Assessment Period	CPP Period				
	FY14	FY15	FY16	FY17	FY18	FY19
3rd party damage - rural (all voltages)	1.5	1.5	1.5	1.5	1.5	1.5
3rd party damage - urban (11kV and 33kV)	1.9	1.9	1.9	1.9	1.9	1.9
External factors - rural (all voltages)	17.9	17.9	17.9	17.9	17.9	17.9
External factors - urban (11kV and 33kV)	6.7	6.7	6.7	6.7	6.7	6.7
System failure - rural (11kV)	12.7	11.7	10.7	9.7	8.6	7.6
System failure - urban (11kV)	20.0	17.4	14.9	12.3	9.8	7.2
System failure - rural (33kV and 66kV)	2.1	2.1	2.1	2.1	2.1	2.1
System failure - urban (33kV)	0.0	0.0	0.0	0.0	0.0	0.0
Planned outages - rural (all voltages)	11.8	11.8	11.8	11.8	11.8	11.8
Planned outages - urban (11kV and 33kV)	3.7	3.7	3.7	3.7	3.7	3.7
All causes - urban (66kV)	18.0	18.2	13.4	13.4	9.0	4.3
All causes - Transpower spur assets	1.9	2.8	2.9	3.0	3.0	3.0
Total	**98.1**	**95.7**	**87.4**	**84.0**	**76.0**	**67.8**

For SAIFI, the number of interruptions reduces from 1.25 in FY15 to 0.8 in FY19. By way of comparison the historical average for the FY08-FY12 period (excluding earthquake outages) is 0.81 interruptions. The historical average for the FY05-FY09 period (used to establish the DPP quality standards) is 0.75 interruptions.

SAIFI - Before Normalisation	Assessment Period	CPP Period				
	FY14	FY15	FY16	FY17	FY18	FY19
3rd party damage - rural (all voltages)	0.02	0.02	0.02	0.02	0.02	0.02
3rd party damage - urban (11kV and 33kV)	0.04	0.04	0.04	0.04	0.04	0.04
External factors - rural (all voltages)	0.18	0.18	0.18	0.18	0.18	0.18
External factors - urban (11kV and 33kV)	0.07	0.07	0.07	0.07	0.07	0.07
System failure - rural (11kV)	0.14	0.13	0.12	0.11	0.10	0.10
System failure - urban (11kV)	0.38	0.33	0.28	0.23	0.18	0.13
System failure - rural (33kV and 66kV)	0.05	0.05	0.05	0.05	0.05	0.05
System failure - urban (33kV)	0.00	0.00	0.00	0.00	0.00	0.00
Planned outages - rural (all voltages)	0.05	0.05	0.05	0.05	0.05	0.05
Planned outages - urban (11kV and 33kV)	0.02	0.02	0.02	0.02	0.02	0.02
All causes - urban (66kV)	0.32	0.33	0.25	0.25	0.17	0.10
All causes - Transpower spur assets	0.03	0.04	0.04	0.06	0.06	0.06
Total	**1.29**	**1.25**	**1.11**	**1.07**	**0.94**	**0.80**

6.4.4 Proposed standard

Deriving the reliability limits

The SAIDI and SAIFI reliability limits for each year of the regulatory period are calculated as µSAIDI + σSAIDI and µSAIFI + σSAIFI.

In order to replicate the DPP method, it is necessary to normalise the data using the DPP method for extreme event day normalisation. This requires:

- determining the boundary values (for the purpose of determining the historical normalised reference datasets)
- assessing how those boundary values are applied in deriving the limits
- determining the boundary values to be used in assessing compliance with the CPP limits throughout the CPP regulatory period.

It is also necessary to determine the standard deviation allowance to be included in each limit, consistent with the DPP approach.

Determining boundary values

The DPP methodology normalises daily SAIDI and SAIFI values using boundary values. A single daily value may be made up of a number of different interruptions, the sum of which is normalised to the boundary value if it exceeds that value.

The DPP 2.5 beta method is used to calculate the boundary values to be assumed when deriving the CPP limits. The FY08 - FY12 reference data is used to determine revised boundary values for SAIDI and SAIFI, after applying the 2.5 beta method. This is consistent with our overall approach to determining the CPP limits, which uses, as a starting position, the most recent five year dataset available. In deriving the SAIDI or SAIDI attributable to each limit for each year of the CPP period, we have relied on extrapolating historical data, as described in the preceding section of the proposal. In performing this extrapolation we have used normalised datasets. These are shown in detail in Appendix 9.

As we disaggregated the normalised data by cause, voltage and location, it was necessary to allocate the boundary value on each MED in the FY08-FY12 dataset to each interruption on that MED.

DPP and revised boundary values for the CPP period

	DPP	Revised	FY15	FY16	FY17	FY18	FY19
BSAIDI	5.0	6.4	6.2	5.7	5.5	5.0	4.4
BSAIFI	0.08	0.09	0.09	0.08	0.07	0.07	0.06

Deriving µSAIDI and µSAIFI

µSAIDI and µSAIFI are calculated using the estimates for each cause and voltage derived from the relevant historical datasets as documented above, and normalised using the boundary values derived from FY08-FY12 data referred to above.

DPP and revised annual µSAIDI and µSAIFI for the CPP period

	DPP	Revised	FY15	FY16	FY17	FY18	FY19
µSAIDI	53.0	97.2	94.7	86.5	83.1	75.2	67.0
µSAIFI	0.68	1.29	1.25	1.11	1.07	0.94	0.80

Summary of µSAIDI and µSAIFI by cause (after normalisation)

The following tables summarise the SAIDI and SAIFI attributed to each cause during the CPP period for the purpose of deriving the CPP limits, using our bottom up method described above. SAIDI minutes reduce from 94.7 minutes in FY15 to 67.0 minutes in FY19. By way of comparison the historical average for the FY08-FY12 period (excluding earthquake outages) is 68.4 SAIDI minutes. The historical average for the FY05-FY09 period (used to establish the DPP quality standards) is 55.0 SAIDI minutes.

SAIDI - Normalised	Assessment Period	CPP Period				
	FY14	FY15	FY16	FY17	FY18	FY19
3rd party damage - rural (all voltages)	1.5	1.5	1.5	1.5	1.5	1.5
3rd party damage - urban (11kV and 33kV)	1.9	1.9	1.9	1.9	1.9	1.9
External factors - rural (all voltages)	17.6	17.6	17.6	17.6	17.6	17.6
External factors - urban (11kV and 33kV)	6.7	6.7	6.7	6.7	6.7	6.7
System failure - rural (11kV)	12.4	11.4	10.5	9.5	8.6	7.6
System failure - urban (11kV)	19.9	17.3	14.8	12.2	9.7	7.1
System failure - rural (33kV and 66kV)	2.1	2.1	2.1	2.1	2.1	2.1
System failure - urban (33kV)	0.0	0.0	0.0	0.0	0.0	0.0
Planned outages - rural (all voltages)	11.8	11.8	11.8	11.8	11.8	11.8
Planned outages - urban (11kV and 33kV)	3.7	3.7	3.7	3.7	3.7	3.7
All causes - urban (66kV)	18.0	18.2	13.4	13.4	9.0	4.3
All causes - Transpower spur assets	1.6	2.5	2.6	2.7	2.7	2.7
Total	**97.2**	**94.7**	**86.5**	**83.1**	**75.2**	**67.0**

For SAIFI, the number of interruptions reduces from 1.25 in FY15 to 0.8 in FY19. By way of comparison the historical average for the FY08-FY12 period (excluding earthquake outages) is 0.81 interruptions. The historical average for the FY05-FY09 period (used to establish the DPP quality standards) is 0.74 interruptions.

SAIFI - Normalised	Assessment Period	CPP Period				
	FY14	FY15	FY16	FY17	FY18	FY19
3rd party damage - rural (all voltages)	0.02	0.02	0.02	0.02	0.02	0.02
3rd party damage - urban (11kV and 33kV)	0.04	0.04	0.04	0.04	0.04	0.04
External factors - rural (all voltages)	0.18	0.18	0.18	0.18	0.18	0.18
External factors - urban (11kV and 33kV)	0.07	0.07	0.07	0.07	0.07	0.07
System failure - rural (11kV)	0.14	0.13	0.12	0.11	0.10	0.10
System failure - urban (11kV)	0.38	0.33	0.28	0.23	0.18	0.13
System failure - rural (33kV and 66kV)	0.05	0.05	0.05	0.05	0.05	0.05
System failure - urban (33kV)	0.00	0.00	0.00	0.00	0.00	0.00
Planned outages - rural (all voltages)	0.05	0.05	0.05	0.05	0.05	0.05
Planned outages - urban (11kV and 33kV)	0.02	0.02	0.02	0.02	0.02	0.02
All causes - urban (66kV)	0.32	0.33	0.25	0.25	0.17	0.10
All causes - Transpower spur assets	0.03	0.04	0.04	0.06	0.06	0.06
Total	**1.29**	**1.25**	**1.11**	**1.07**	**0.94**	**0.80**

Boundary values for assessment purposes

In assessing compliance with the CPP, it will be necessary to normalise the annual outage data in each CPP year using a similar method as the DPP. In order to do this, SAIDI and SAIFI boundary values are required.

As it is assumed that the SAIDI and SAIFI limits will reduce over the CPP period due to reliability improvements, it is also appropriate to adjust the boundary values to be used for this purpose, over the CPP period. We have aligned the boundary values with the stepped change in µSAIDI and µSAIFI for each year of the CPP regulatory period. Accordingly the annual boundary values are assumed to reduce to the end of the CPP period, at the same rate as the underlying normalised SAIDI and SAIFI used to derive the limits. These are illustrated in the following table which shows the current DPP boundary values, the revised boundary values (derived from the FY08-FY12 dataset and used for the purpose of deriving the limits) and the gradual reduction in the boundary values over the CPP period.

DPP and revised boundary values for the CPP period							
	DPP	Revised	FY15	FY16	FY17	FY18	FY19
BSAIDI	5.0	6.4	6.2	5.7	5.5	5.0	4.4
BSAIFI	0.08	0.09	0.09	0.08	0.07	0.07	0.06

Deriving σSAIDI and σSAIFI

The standard deviation allowance provides a buffer against normal year on year variation in reliability performance. It is a component of the DPP quality standards, and we propose it is retained for the CPP quality standards. It assists to protect against breaches of quality standards which are not reflective of underlying deterioration in quality performance. This is prudent, and in our case critical due to the abnormal circumstances we face at this time.

Our proposed method uses the standard deviation of the FY08-FY12 normalised reference dataset (calculated using the DPP method). The normalised reference dataset excludes all outages attributed to the earthquakes.

As it is assumed that the underlying SAIDI and SAIFI (as measured by µSAIDI and µSAIFI) will reduce over the CPP period due to expected reliability improvements, it is appropriate to align the *σSAIDI* and *σSAIFI* values with the stepped change in µSAIDI and µSAIFI for each year of the CPP regulatory period. This is the same as the approach adopted for the boundary values, described above. Accordingly *σSAIDI* and *σSAIFI* also reduce between the beginning and the end of the CPP period, at the same rate as µSAIDI and µSAIFI. This is illustrated in the following table.

DPP and revised annual SAIDI/SAIFI standard deviation (σ) values for the CPP period

	DPP	Revised	FY15	FY16	FY17	FY18	FY19
σSAIDI	6.7	9.3	9.0	8.2	7.9	7.2	6.4
σSAIFI	0.10	0.11	0.11	0.09	0.09	0.08	0.07

SAIDI and SAIFI limits

The tables below show our proposed SAIDI and SAIFI Limits derived from µSAIDI, µSAIFI, σSAIDI and σSAIFI as set out above.

		Assessment period	CPP period				
SAIDI	**DPP limit**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
µSAIDI	53.0	97.2	94.7	86.5	83.1	75.2	67.0
σSAIDI	6.7	9.3	9.0	8.2	7.9	7.2	6.4
$\text{SAIDI}_{\text{LIMIT}}$	**59.7**	**106.4**	**103.8**	**94.7**	**91.0**	**82.4**	**73.4**

		Assessment period	CPP period				
SAIFI	**DPP limit**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
µSAIFI	0.68	1.29	1.25	1.11	1.07	0.94	0.80
σSAIFI	0.10	0.11	0.11	0.09	0.09	0.08	0.07
$\text{SAIFI}_{\text{LIMIT}}$	**0.78**	**1.40**	**1.36**	**1.21**	**1.16**	**1.02**	**0.87**

Appendix 9 includes more detailed data tables which show how our proposed limits were derived. The spreadsheets used to derive these limits accompany this proposal. A list of the spreadsheets is included at the end of this section.

Our proposed limits indicate significant improvements in expected reliability over the CPP period consistent with the expectations of our consumers for quality of supply to be restored.

Our methodology has attempted to replicate the core features of the current DPP method, using recent information, modified where necessary to incorporate earthquake consequences for particular assets and/or sources of outage.

In our view it is not realistic to achieve pre earthquake reliability performance within the CPP period, given the prolonged rebuild plan for Christchurch and our inspection, testing, maintenance and replacement programmes which will continue to address earthquake consequences for a number of years to come.

Notwithstanding these ongoing programmes however, we do expect to achieve significant improvements in reliability within the CPP period, and we believe that it is in the interests of our consumers for these to be reflected in our CPP quality standards.

Assessing compliance with the standards

We propose that the same compliance tests are applied during the CPP period as those which currently apply under the DPP.

Under the 2011-2015 DPP compliance against the quality standards is based on a multi-year assessment. Under the DPP an EDB will comply with its quality standards during a particular Assessment Period, if:

a) the Assessed SAIDI and SAIFI Values for the Assessment Period are less than or equal to the respective Reliability Limits; or
b) the Assessed SAIDI and SAIFI Values in the previous two extant Assessment Periods did not exceed the respective Reliability Limits.

The purpose of this test is to allow for normal year on year variation in reliability performance due to the influence of events which are outside the control of an EDB.

We propose that the same 'two out of three year' compliance assessment is incorporated into our CPP quality standards, because we are subject to the same influences which generate annual variations in reliability as anticipated when the DPP limits were set.

In undertaking the annual assessments, we propose that the boundary values used to normalise the data for each assessment period are as follows:

DPP and revised boundary values for the CPP period

	DPP	Revised	FY15	FY16	FY17	FY18	FY19
BSAIDI	5.0	6.4	6.2	5.7	5.5	5.0	4.4
BSAIFI	0.08	0.09	0.09	0.08	0.07	0.07	0.06

As described above, these have been set to trend with the underlying µSAIDI and µSAIFI to reflect the change in reliability performance expected over the CPP period.

6.5 Evaluation of other approaches

IM 5.4.5(d)

To assist in the evaluation of our proposed CPP limits we have also:

- applied the DPP method to an updated historical dataset (FY08-FY12) and compared this approach to our proposed CPP limits
- applied our proposed CPP method to the historical reference dataset (FY05-FY09) to create a revised DPP standard.

6.5.1 Applying the DPP method to an updated dataset

We have considered the impact on the quality standards by simply applying the DPP method to an updated historical dataset. We have used FY08-FY12 data as this is the most recent five year period for which information is available.

The SAIDI and SAIFI limits, which are derived by applying the current DPP method to a FY08-FY12 historical reference period, are shown in the table below. We also show the current DPP SAIDI and SAIFI limits for comparison, along with our proposed quality standards to apply during the CPP.

SAIDI	Current DPP quality standards	Updated DPP quality standards	Proposed CPP limits				
	FY05 - FY09	FY08 - FY12	FY15	FY16	FY17	FY18	FY19
µSAIDI	53.0	**89.7**	94.7	86.5	83.1	75.2	67.0
σSAIDI	6.7	**15.0**	9.0	8.2	7.9	7.2	6.4
$SAIDI_{LIMIT}$	59.7	**104.7**	103.8	94.7	91.0	82.4	73.4

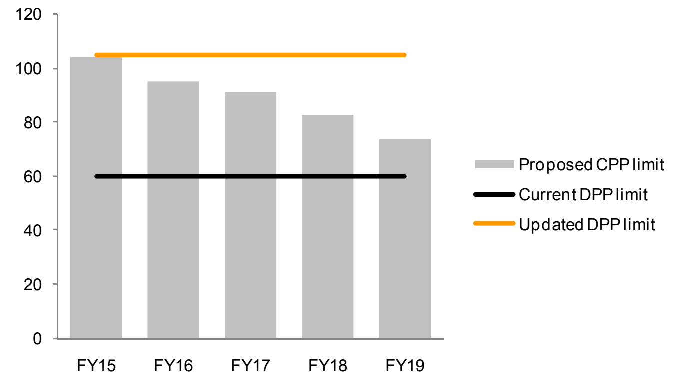
SAIFI	Current DPP quality standards	Updated DPP quality standards	Proposed CPP limits				
	FY05 - FY09	FY08 - FY12	FY15	FY16	FY17	FY18	FY19
µSAIFI	0.68	**1.04**	1.25	1.11	1.07	0.94	0.80
σSAIFI	0.10	**0.18**	0.11	0.09	0.09	0.08	0.07
$SAIFI_{LIMIT}$	0.78	**1.22**	1.36	1.21	1.16	1.02	0.87

The updated DPP quality standard (which uses the FY08-FY12 reference period) results in significantly higher limits than the current DPP limits. This is because this reference period includes the direct and indirect consequences of the earthquakes. We do not believe it is realistic to include in our CPP quality standards the direct consequences of the earthquakes. Furthermore, this would not be consistent with the improvements in reliability that are expected with the proposed programme to reinstate the resilience of our network. It is also not consistent with the requirements of our consumers for a reliable power supply. We therefore do not believe that this approach is consistent with the long term interests of our consumers.

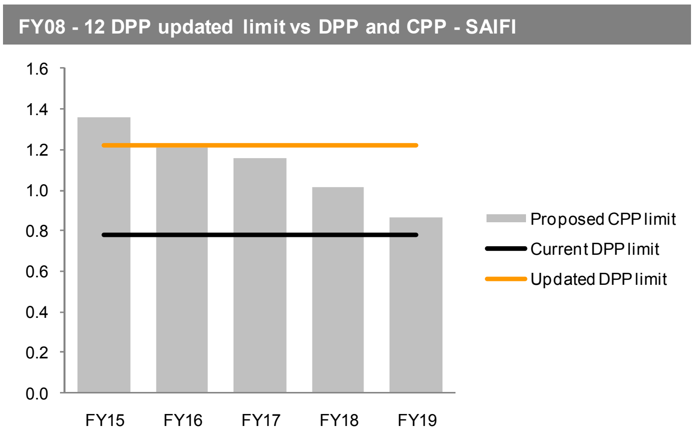
The following charts illustrate the updated DPP quality limits, the current DPP quality limits and our proposed CPP quality limits.

The updated DPP SAIDI limit is 104.72, compared to the current DPP SAIDI limit of 59.73. Our proposed CPP SAIDI limit starts at 103.8 in FY15 and reduces to 73.4 in FY19.

FY08 - FY12 DPP updated limit vs DPP and CPP - SAIDI



The updated DPP SAIFI limit is 1.22, compared to the current DPP SAIFI limit of 0.78. Our proposed CPP SAIFI limit starts at 1.35 in FY15 and reduces to 0.86 in FY19.



We believe that updated DPP SAIDI and SAIFI Limits using FY08-FY12 data are not consistent with our realistically achievable performance. This method includes the direct consequences of the earthquakes which we do not believe should be included for the purpose of setting future standards. In addition, our network investment will result in stepped changes to our reliability performance through to the end of the CPP period. Accordingly we have proposed a better approach which includes decreasing limits over the CPP period. This improves the quality of our supply to our consumers, and by the end of the CPP period we expect to be well on the way to achieving pre earthquake performance. By FY19, our proposed SAIDI limit is 23% higher than our current DPP SAIDI limit and our proposed SAIFI limit is 12% higher than our current DPP SAIFI limit.

We anticipate that further improvements will be achieved following the end of the CPP regulatory period as we continue to repair our network, restore its resilience and the wider Canterbury rebuild moves past its peak.

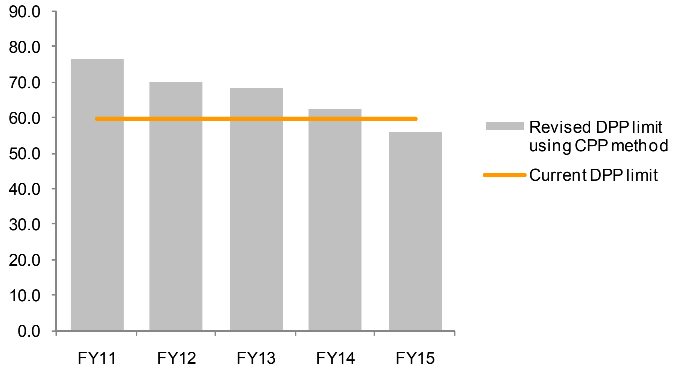
6.5.2 Applying our proposed CPP method to the prior period

One CPP IM requirement (set out at clause 5.4.5(d)) is that we provide:

"an estimation and evaluation of the effect of the proposed quality standard variation had it applied in an earlier period of 5 years, by use of historic data, by contrast with the quality standards specified in the DPP determination."

In order to meet this requirement we have applied our proposed CPP method to the historical reference dataset (FY05-FY09) used to derive the current DPP quality standards. We have created revised DPP quality standards for the current DPP period (FY11–FY15). The chart below illustrates the SAIDI results.

Historical normalised SAIDI with revised DPP limit using CPP method and DPP limit



The following table outlines the revised SAIDI Limit using our proposed CPP method applied to the DPP regulatory period. This is based on data from the historical period, FY05-FY09, as for the current DPP.

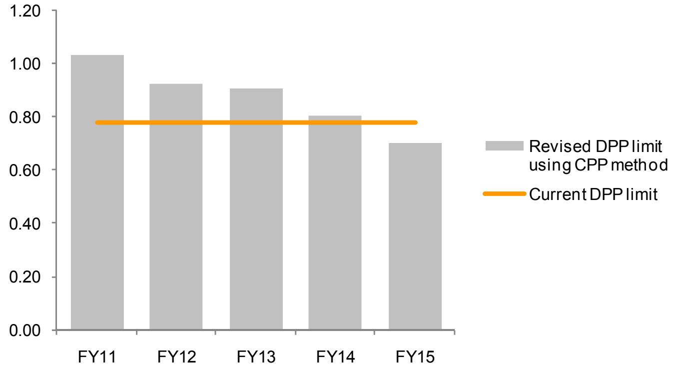
Orion reliability limits

SAIDI	FY11	FY12	FY13	FY14	FY15
μSAIDI	70.5	64.4	63.1	57.5	51.5
σSAIDI	6.1	5.6	5.5	5.0	4.5
SAIDI$_{LIMIT}$	76.6	70.0	68.5	62.4	56.0

The current DPP SAIDI limit is 59.73. Applying our proposed CPP method to the FY11-FY15 DPP regulatory period, results in a SAIDI limit which starts at 76.6 minutes in FY11 and reduces to 56.0 minutes in FY15.

The following chart and table outline the revised SAIFI Limit using our proposed CPP method applied to the DPP regulatory period. Once again this is based on FY05-FY09 data.

Historical normalised SAIFI with revised DPP limit using CPP method and DPP limit



Orion reliability limits

SAIFI	FY11	FY12	FY13	FY14	FY15
μSAIFI	0.94	0.84	0.83	0.73	0.64
σSAIFI	0.09	0.08	0.08	0.07	0.06
SAIFI$_{LIMIT}$	1.03	0.92	0.90	0.80	0.70

The current DPP SAIFI limit is 0.78. Applying our proposed method to the FY11-FY15 DPP regulatory period, results in a SAIFI limit which starts at 1.03 in FY11 and reduces to 0.70 in FY15.

How we applied our proposed method to the prior period

Our proposed CPP (bottom up) method includes specific consideration of the consequences of the earthquakes, our planned response to those, as well as the impacts of the wider Christchurch rebuild. Accordingly, in order to meet the requirements of CPP IM clause 5.4.5(d) we have had to make a number of assumptions in order to apply our proposed method into the prior period. These assumptions include:

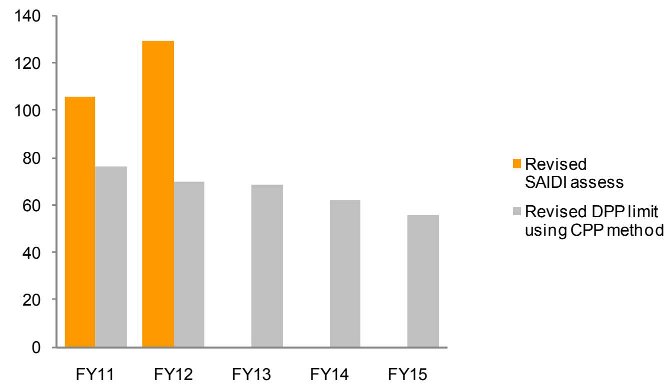
- we used the FY05 – FY09 dataset as per the current DPP, where, for the purpose of our CPP method, we have used the FY08 – FY12 dataset
- as we have used an annualised 2012 calendar year in order to derive estimated outages attributed to urban network third party causes for the CPP, we have used the final year of the historical period (FY09) for the prior period analysis
- as we have used a 24 month post earthquake period in order to derive estimated outages attributed to urban network system failure for the CPP, we have used the last two years of the historical period (FY08 and FY09) for the prior period analysis
- as we assume 11kV system failure outages reduce over the CPP period, we have applied the same gradient across the prior period DPP data
- we have applied the same number of assumed annual interruptions on the urban 66kV network from our proposed CPP method as well as the same SAIDI and SAIFI impacts, to the prior period analysis
- Transpower spur asset outages have not been included in the reference period as we have not purchased any Transpower assets during the reference or DPP period (to date)
- boundary and standard deviation calculations were performed by applying the standard DPP method, but stepped down each year at the same rate as that proposed for in our CPP method.

As demonstrated by the number of assumptions made, the application of the proposed CPP method to the current DPP is highly academic. None of the major circumstances which are driving our proposed quality standards are relevant to the historical period used to derive the current DPP standards. While this analysis helps to demonstrate the impact of the alternative method we are proposing, it is not a valid indication of plausible quality standards for the current DPP period, because of the substantially different circumstances we now face on our network.

How would we have performed in the prior period

In the following charts we show our SAIDI and SAIFI assessments for the first two years of the DPP period against the revised DPP limits calculated using our proposed CPP method.

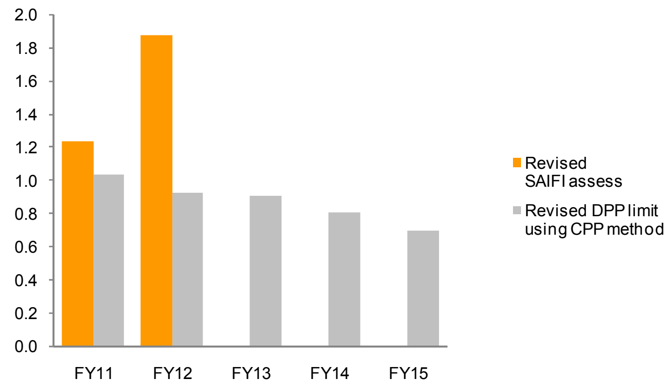
SAIDI performance under the revised DPP limit using CPP method



SAIDI performance under the revised DPP limit using the CPP method

	FY11	FY12	FY13	FY14	FY15
Revised SAIDI assess	106.0	129.6			
Revised DPP limit using CPP method	76.6	70.0	68.5	62.4	56.0
Exceeds	Yes	Yes			

SAIFI performance under the revised DPP limit using CPP method



SAIFI performance under the revised DPP limit using the CPP method

	FY11	FY12	FY13	FY14	FY15
Revised SAIFI assess	1.24	1.87			
Revised DPP limit using CPP method	1.03	0.92	0.90	0.80	0.70
Exceeds	Yes	Yes			

In FY11 and FY12 we would have exceeded the revised DPP Limits for both SAIDI and SAIFI. Thus we would have breached the quality standards, by failing to comply with the two out of three year assessment criteria. This is expected due to the magnitude of the earthquake damage to our network and the large outages which occurred as a result.

6.6 Independent engineer’s review

IM 5.4.5(c)

Independent engineer, Richard Gibbons of LineTech Consulting Limited, has reviewed our proposed CPP quality standards.

Mr Gibbons’ brief, consistent with the CPP IMs, was to consider whether our CPP network reliability proposals reflect the realistically achievable performance of our network over the CPP regulatory period. Mr Gibbons also considered our analysis of past SAIDI and SAIFI performance and our forecast network investment programme.

Mr Gibbons’ reviewed whether our proposed network reliability targets are reasonable and whether our statistical analysis to set our targets was carefully considered.

Mr Gibbons recommended that we increase our draft proposed allowance for planned outages in the urban area, effectively to double the historical average of these outages in recognition of the increased building activity in the city as the rebuild progresses. We accepted Mr Gibbons’ recommendation. This was the only change we made to our draft proposed CPP quality standards. This increased our proposed SAIDI limit for FY15 from 102.5 minutes to 103.8 minutes, and our proposed SAIFI target from 1.35 to 1.36 supply interruptions.

Mr Gibbons’ report concludes that *“the proposals and targets provide an appropriate trade-off between the proposed expenditure and resultant improvement in network performance from its present damaged state within the realistic availability of resources.”*

A copy of Mr Gibbons’ report is included as Appendix 3.

6.7 Consultation with consumers

IM 5.4.5(b)

We have consulted with our consumers and other stakeholders regarding our proposed quality standards over the CPP period. This consultation is summarised in our CPP application.

Most of the consumer feedback focussed on our proposed price path. There were no written objections to our proposed CPP quality standards. In addition the numerous discussions we had with stakeholder groups during our CPP consultation supported our intention to restore network resilience and reliability. This, along with the consultation we undertook in 2006 on our security of supply standards, endorses our proposal to restore our network as soon as practicable.

Our proposed CPP quality standards reflect a staged approach to network performance restoration. This is realistic, given the amount of work involved and external influences on our reliability performance. It is also consistent with our proposal (endorsed by feedback from consumers) to minimise price shocks to consumers.

We are proud of our pre-earthquake reliability performance, which rated well when compared with other EDBs. This partly reflects the urban nature of our network, and demonstrated in Section 6.1 above, our pre-earthquake performance was in line with NZ trends for high density networks.

We are also proud of the resilience of our network and our emergency measures in response to the earthquakes.

We believe that our proposals are consistent with what consumers require, their long term interests and good industry practice.

6.8 Appendices and supporting documents

Section 6 – Appendices	
Appendix	**Title**
3	LineTech Consulting Report on Proposed Reliability Standards
6	Sub-transmission network architecture review
7	11kV architecture review
8	Cable testing report (Wire Scan)
9	Detailed data tables indicating how proposed limits were derived

Section 6 – Supporting Documentation
Title
Security of Supply Standard consultation
2010 Network Quality Report
NW20.40.01 Contingency Plan - Equipment Failure
NW20.40.02 Contingency Plan - Emergency Generators
NW20.40.03 Continuity Plan -Loss of Supply
NW20.40.05 Disconnection of Demand as Required by ECom Rules
NW20.40.08 Contingency Plan - Relocating the Control Centre
NW20.40.09 Contingency Plan – Security of Supply, Participant Outage Plan

NW70.60.04 Business Continuity Plan – Infrastructure Management
OR.00.00.07 Major Outage Communication Plan
OR00.10.17 Building Emergency Plan – 200-210 Armagh St
NW70.60.04 Business Continuity Plan – Infrastructure Management
SCIRT – Stronger Christchurch Infrastructure Rebuild Plan
CERA – Recovery Strategy for Greater Christchurch

7 Proposed price path

7 Proposed price path

7.1 Summary of our proposed price path

7.1.1 Proposed price path

Our proposed price path comprises MAR before tax of $156m for FY15, and an X factor of -1.19% for FY16 - FY19 to apply in the CPI-X component of our price path. The present value of the MAR series after tax is equivalent to the present value of the series of BBAR after tax. This is illustrated below.

Derivation of maximum allowable revenue series ($000 nominal)	**CPP Period**				
	FY15	**FY16**	**FY17**	**FY18**	**FY19**
Inflation rate		2.17%	2.17%	2.17%	2.17%
X factor		-1.19%	-1.19%	-1.19%	-1.19%
Weighted average growth in quantities		0.79%	0.80%	0.85%	0.76%
MAR before tax	155,598	162,136	168,974	176,185	183,540
Regulatory tax allowance	14,234	15,742	16,437	17,183	17,852
MAR after tax	141,364	146,394	152,536	159,002	165,688
TF_{REV}	1.028	1.028	1.028	1.028	1.028
MAR after tax year end	145,252	150,420	156,731	163,375	170,245
	PV at 1 April 2014				
PV of series of MAR after tax	**642,505**				

Note: The annual rate of change in the price path is specified as CPI-X, thus an X factor of -1.19% means real price increases of 1.19%

Note: The discount rate used to calculate the PV is the 5-year CPP WACC (6.92%)

Present value of series of BBAR after tax ($000 nominal)	**CPP Period**				
	FY15	**FY16**	**FY17**	**FY18**	**FY19**
BBAR before tax	151,819	164,599	169,450	176,095	185,020
Regulatory tax allowance	14,234	15,742	16,437	17,183	17,852
BBAR after tax	137,585	148,857	153,012	158,912	167,168
TF_{REV}	1.028	1.028	1.028	1.028	1.028
BBAR after tax (year-end)	141,369	152,951	157,220	163,282	171,765
	PV at 1 April 2014				
PV of series of BBAR after tax	**642,505**				

Note: The discount rate used to calculate the PV is the 5-year CPP WACC (6.92%)

Our derivation of MAR is explained in Section 7.2. Our derivation of BBAR is explained in Section 7.3.

An important feature of BBAR is our proposed alternative depreciation method, which reduces the depreciation allowance within the CPP regulatory period, relative to the standard method. This flows through to a lower CPP price path than would otherwise apply. Our proposed depreciation method is explained in Section 7.5.3.

7.1.2 Claw-back

We also propose that our CPP price path includes the recovery of claw-back. The following table summarises the value of claw-back which we have determined for the period 4 September 2010 – 31 March 2014. The present value of claw-back at the commencement of the CPP regulatory period is $86.3m.

Our derivation of claw-back is explained in Section 7.2.2.

The value of claw-back ($000 nominal)	**Current Period**			**Assessment Period**	
	FY11a	**FY11b**	**FY12**	**FY13**	**FY14**
BBAR before tax (year end)	57,569	90,313	135,466	160,570	193,207
Actual and projected revenues (year end)	64,195	76,681	129,322	141,091	143,937
Difference	(6,626)	13,632	6,144	19,479	49,270
PV of difference for FY11	8,808				
PV of difference			7,157	21,023	49,270
Total PV of difference (at 1 April 2014)	**86,259**				

*We have used the DPP cost of debt (7.93%) to discount these differences

Our proposed claw-back recovery increases MAR before tax in FY15 to $164.8m, as illustrated below. The proposed claw-back recovery in FY16 - FY19 is consistent with the slope of our MAR before claw-back over the CPP period. That is, it is consistent with an annual CPI-X rate of change where X is equivalent to -1.19% (and hence provides for annual average price increases of CPI + 1.19%).

MAR including recovery of clawback ($000 nominal)	**CPP Period**				
	FY15	**FY16**	**FY17**	**FY18**	**FY19**
MAR before tax	155,598	162,136	168,974	176,185	183,540
Clawback recovery over CPP period	9,175	9,560	9,964	10,389	10,822
MAR before tax plus claw-back recovery	164,773	171,696	178,937	186,574	194,362

We understand that it is possible to include a longer term recovery mechanism for the claw-back proportion of our revenue. Our proposed price path will not fully recover our claw-back costs within the CPP regulatory period.

Our CPP period will be five years. We propose to recover our claw-back over 10 years. We propose to recover $43.13m (in present value terms) of the $86.3m of claw-back (half) over the CPP regulatory period.

We propose to recover the remaining $43.13m (in present value terms) in the five years immediately following the CPP period (to FY24). The table below shows the value of claw-back, and the proportions recovered during the CPP regulatory period and subsequently.

Claw-back recovery ($000 nominal)	PV at 1 April 2014	PV at 1 April 2019
Value of clawback	86,259	
Value of clawback to be recovered in CPP period	43,130	
Value of clawback to be recovered after CPP period	43,130	57,418

Note: The rate used to derive the PV at FY19 from the PV at FY14 is the CPP cost of debt (5.89%)

Our proposed claw-back allowance seeks to recover our earthquake related costs which were not anticipated or insurable when our DPP price path was set. This ex-post cost recovery is:

- consistent with the manner in which our DPP price path was set (because our DPP price path includes no allowance for unanticipated costs of this nature)
- in the long term interests of consumers.

It ensures that we retain the economic incentives to continue to provide the services that consumers require of us because we are compensated for our prudent and efficient costs in providing those services, including a risk adjusted commercial return on our investment.

Our proposed cost recovery includes ex-post compensation for reduced revenues as a result of the earthquakes which has contributed to our under recovery of costs since the earthquakes. We sought and carefully considered independent, and peer reviewed, expert economic advice on this matter (which is included in Appendix 1 and 2). We believe that where reduced consumption arising from a catastrophic event has contributed to under recovery of costs, it should be compensated for on an ex-post basis under a CPP, to ensure we are able to recover our prudent and efficient costs. No provision for such uninsurable risk was allowed for in our pre-earthquake DPP price path.

While requirements in other jurisdictions need to be taken in context, we have observed regulatory decisions and provisions in Australia and the UK where price controls are able to be revisited within a regulatory period in response to unforeseen events, on the grounds of higher costs and lower demand. Examples of relevant decisions and provisions are included as Appendix 10. While informative, approaches in other jurisdictions do need to be treated with caution, and our application is made in the context of New Zealand's regulatory framework including Part 4 of the Commerce Act and the IMs.

We believe we prepared as prudently as possible for the possibility of catastrophic events. However Orion, like other infrastructure entities, cannot feasibly insure its entire network and revenues against catastrophic damage.

We have not insured overhead lines and underground cables because it has been, and still is, uneconomic to do so. The premiums charged for other network assets, such as substations and buildings, are more affordable. Consequently, we have and continue to fully insure all of our key substations at full estimated replacement cost. We continue to insure our substations and other assets where insurance premiums are at a prudent level.

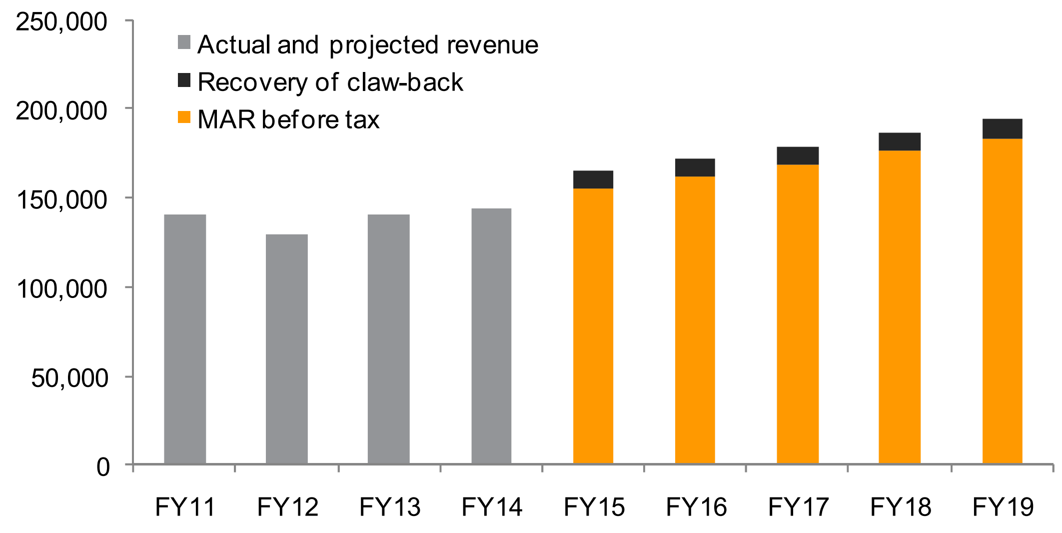
An independent expert report prepared by international insurance broker Marsh confirms that EDBs around the world face the same insurance circumstances: underground cables and overhead lines risks are normally uninsured because insurance underwriters are not able to provide material damage and business interruption coverage for them. Marsh also confirms that, in its opinion, our approach to insurance has been entirely appropriate, reasonable and consistent with that of other network companies in Australasia. The Marsh report is included as Appendix 11.

We have made no allowance in our CPP proposal for unanticipated costs associated with possible future catastrophic events. We have no self insurance allowance in our opex forecast. If such events occur within the CPP regulatory period, we are able to reopen the CPP to address the impacts at that time. Thus we propose an ex-post approach to the recovery of the consequences of potential future catastrophes, as anticipated in the IMs. This is the same as the 'ex-post' claw-back allowances that this CPP proposal addresses for the consequences of the 2010 and 2011 Canterbury earthquakes.

7.1.3 Pricing impacts

The chart below illustrates actual and projected revenues in the years prior to the start of the CPP regulatory period and the MAR (including the claw-back component) during the CPP period.

MAR before tax plus claw-back recovery ($000 nominal)



Our proposed price path (including claw-back) represents a nominal increase to allowable revenue of 18.5% in FY15, and approximately 4.2% each year from FY16 to FY19. After removing the effects of forecast inflation and growth in quantities, this represents real price increases of 15.0% in FY15 and 1.19% each year from FY16 to FY19.

We anticipate that this proposed price path is likely to avoid a significant step change in prices at the end of the CPP period. We believe that this is an important consideration as it promotes price stability for consumers. If prices were lower at the beginning of the CPP period, and the rate of change higher during the CPP period, average prices at the end of the CPP period would be higher. This may lead to a reduction in prices after the end of the CPP period.

While our proposed initial price increase reflects a step up from current prices, we have tested the impact of our CPP proposal with our consumers. This is summarised in Section 2 of our CPP application document which accompanies this proposal.

While consumers are concerned about the price impacts of our proposal, they largely agree we should recover our costs, and they support our plans to spread our cost recovery over ten years. We believe that our proposed price path is consistent with consumer feedback.

In the remainder of this section we set out our derivation of each component of the building blocks which underpin the MAR, including claw-back, and the rationale for the price path which we propose.

7.2 Maximum allowable revenues

IM 5.4.8 and 5.3.4

MAR is the maximum amount of revenue that an EDB is allowed to recover from consumers in a given year. It is the key financial item to be determined in a CPP determination.

MAR differs from BBAR as a result of smoothing. BBAR can be somewhat volatile over the CPP regulatory period. MAR is smoothed so that real price changes (ie independent of changes in inflation and quantities) in each year after the first are equal, such that the PV of the series is equal to the PV of the BBAR series.

Determining the series for MAR involves selecting a slope of the path over the period and an initial value. If price increases are required, it involves a trade-off between an initial price increase and subsequent annual price increases.

In addition to the MAR derived from BBAR, we also propose to recover the value of claw-back. As discussed in more detail below, we add our proposed claw-back series to our MAR series in order to determine our proposed CPP price path.

7.2.1 Maximum allowable revenue (pre and post tax)

In this section we present amounts for MAR, both excluding and including the recovery of claw-back.

IM requirements

Clause 5.4.8(1) of the CPP IM requires that a CPP proposal must contain amounts for

- MAR before tax
- MAR after tax

for each disclosure year of the CPP regulatory period.

Summary of maximum allowable revenue

Excluding claw-back

The table below shows MAR, before and after tax, from FY15 to FY19.

Maximum allowable revenue ($000 nominal)	CPP Period				
	FY15	FY16	FY17	FY18	FY19
MAR before tax	155,598	162,136	168,974	176,185	183,540
MAR after tax	141,364	146,394	152,536	159,002	165,688

Under our proposed price path, MAR before tax is $156m in FY15, rising to $184m in FY19.

Including claw-back

The table below shows MAR before tax plus the proposed recovery of claw-back for the CPP period.

MAR including recovery of clawback ($000 nominal)	CPP Period				
	FY15	FY16	FY17	FY18	FY19
MAR before tax	155,598	162,136	168,974	176,185	183,540
Clawback recovery over CPP period	9,175	9,560	9,964	10,389	10,822
MAR before tax plus claw-back recovery	164,773	171,696	178,937	186,574	194,362

After including the recovery of claw-back, we propose a price path which commences with allowable revenue before tax of $165m in FY15, increasing to $194m in FY19.

We describe below how we determine MAR, while in Section 7.2.2 we set out our derivation of the amounts for the recovery of claw-back.

Determining maximum allowable revenue before and after tax

Clause 5.3.4(1) of the CPP IM states that the present value of the series of values of MAR after tax must equal the present value of the series of BBAR after tax less any value of claw-back for the CPP regulatory period. As explained above (and in Section 7.2.2), we determine MAR without claw-back, and then add the recovery of claw-back. The present value of the series of MAR after tax must equal the present value of the series of BBAR after tax for the CPP regulatory period.

Present value of building blocks allowable revenue after tax

BBAR after tax, as defined in clause 5.3.3(1) of the CPP IM is in ‘revenue-date’ terms. In order to calculate the present value of the BBAR series, we convert the revenue date amounts into ‘year-end’ terms. To do this, we use the timing factor for revenue specified in clause 5.3.2(4)(b) of the IM.

Clause 5.3.4(3) of the CPP IM specifies that the discount rate used to determine the present value of the BBAR series must be the CPP WACC.

The table below shows how the present value of BBAR after tax during the CPP period is determined. It shows BBAR after tax, in revenue-date and year-end terms, the timing factor adjustment term, and the resulting present value.

Present value of series of BBAR after tax ($000 nominal)	**CPP Period**				
	FY15	**FY16**	**FY17**	**FY18**	**FY19**
BBAR before tax	151,819	164,599	169,450	176,095	185,020
Regulatory tax allowance	14,234	15,742	16,437	17,183	17,852
BBAR after tax	137,585	148,857	153,012	158,912	167,168
TF_{REV}	1.028	1.028	1.028	1.028	1.028
BBAR after tax (year-end)	141,369	152,951	157,220	163,282	171,765
	PV at 1 April 2014				
PV of series of BBAR after tax	**642,505**				

Note: The discount rate used to calculate the PV is the 5-year CPP WACC (6.92%)

We describe how the series for BBAR before tax is determined in Section 7.3.1.

In Section 7.3.6 we discuss the timing factor adjustment terms, and show how TF_{rev} is determined.

We describe how the CPP WACC is determined in Section 7.7.1.

PV of MAR after tax and determining the MAR before tax series

As discussed above, the present value of the series MAR after tax must be equal to the present value of the series of BBAR after tax, as shown above.

The amount for MAR before tax in the first year of the CPP regulatory period is set to ensure this, subject to definition of the slope of the series defined in clause 5.3.4(6) of the CPP IM.

Clause 5.3.4(6) defines MAR before tax, in a disclosure year other than the first in the CPP regulatory period, as the result of the following formula:

$$MAR\ before\ tax = MAR\ before\ tax\ in\ preceding\ year \text{ x } (1 + inflation\ rate) \text{ x } (1 - X\ factor) \text{ x } (1 + weighted\ average\ growth\ in\ quantities)$$

Clause 5.3.4(8) of the CPP IM defines MAR after tax as MAR before tax less the forecast regulatory tax allowance.

The table below shows how the present value of the series for MAR after tax is determined. As discussed above, the series for MAR before tax is set so that this present value equals the present value of BBAR before tax.

The table shows the inputs to the series of MAR before tax – the inflation rate, the X factor and the forecast weighted average growth in quantities. It shows how MAR after tax is derived from the before tax values using the forecast regulatory tax allowance. It then shows how the present value is determined, by adjusting to year-end values and discounting using the CPP WACC (per the calculation for BBAR after tax).

Derivation of maximum allowable revenue series ($000 nominal)	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Inflation rate		2.17%	2.17%	2.17%	2.17%
X factor		-1.19%	-1.19%	-1.19%	-1.19%
Weighted average growth in quantities		0.79%	0.80%	0.85%	0.76%
MAR before tax	155,598	162,136	168,974	176,185	183,540
Regulatory tax allowance	14,234	15,742	16,437	17,183	17,852
MAR after tax	141,364	146,394	152,536	159,002	165,688
TF_{REV}	1.028	1.028	1.028	1.028	1.028
MAR after tax year end	145,252	150,420	156,731	163,375	170,245
	PV at 1 April 2014				
PV of series of MAR after tax	**642,505**				

Note: The annual rate of change in the price path is specified as CPI-X, thus an X factor of -1.19% means real price increases of 1.19%

Note: The discount rate used to calculate the PV is the 5-year CPP WACC (6.92%)

The slope of the path is determined by the X factor. Our proposed price path involves real price increases each year. We have capped the initial change in real prices, including the recovery of claw-back, to 15%. The X factor determines the rate of change in subsequent years required to achieve the PV outcome noted above.

Claw-back is a pre tax amount

We demonstrate above that the present value of MAR after tax is equivalent to the present value of BBAR after tax in accordance with the requirements of clause 5.3.4(1). We have not included the value of claw-back in this assessment because our claw-back allowance is calculated on a pre-tax basis. We do not believe it is appropriate to include a pre-tax value of claw-back in the test required by clause 5.3.4(1) which uses post tax values for BBAR and MAR.

Our claw-back value is determined by calculating the difference between two pre-tax series. While we can determine a post-tax value for the BBAR series, consistent with the regulatory tax method, we cannot do so for the actual/projected revenue series. Furthermore, it is not possible to adjust the pre-tax 'difference' between the two pre-tax series, to translate it to an after tax difference.

We believe that the intent of the test specified in clause 5.3.4(1) is to ensure that the CPP regulatory tax method is being applied correctly. We have demonstrated that the regulatory tax method is applied correctly during the CPP regulatory period by meeting the PV equivalence test for BBAR and MAR (excluding claw-back). We apply exactly the same method in the BBAR which we use in the claw-back period to establish our pre tax BBAR. We suggest that this is sufficient evidence of compliance with the regulatory tax methods.

Our claw-back method is consistent with the method used in the 2012 DPP Determination to apply to other non-exempt EDBs. In this Determination, the value of claw-back is determined on a pre-tax basis, and annual amounts to be recovered are added to the MAR before tax series derived from pre-tax BBAR (excluding claw-back).

We describe how the other inputs, for deriving the proposed MAR series, are determined as follows:

- inflation rate (Section 7.2.3)
- X factor (Section 7.2.4)
- weighted average growth in quantities (Section 7.2.5)
- TF_{rev} (Section 7.3.6)
- forecast regulatory tax allowance (Section 7.6.1)
- WACC (Section 7.7.1).

Information in spreadsheet format

Clause 5.4.8(7) of the CPP IM requires a CPP proposal to present all calculations and values used to determine the amounts for MAR before and after tax from the amounts for BBAR before and after tax (shown in Section 7.3.1). This is to include all calculations and values for the X factor and weighted average growth in quantities, in a spreadsheet format which clearly demonstrates how the amounts for MAR before and after tax have been derived. These spreadsheets accompany this proposal. A list of spreadsheets which support the price path is included at the end of this section of the proposal.

7.2.2 Claw-back

As discussed In Section 7.1.2, we propose adding the value of claw-back to our series for MAR before tax (which we determine without considering claw-back).

In Section 7.2.1 we presented allowable revenue including both MAR and our proposed series for the recovery of claw-back. In the remainder of this section we discuss how we have calculated the claw-back amount.

Calculation of claw-back

The value of claw-back is $86.3m. This is a present value as at 1 April 2014.

Since the earthquakes, we have incurred higher expenditure than was forecast when we set our prices, and received lower revenue as a result of reduced consumption. The appropriate use of claw-back will allow us to recover this under-recovery since the catastrophic event. This ex-post compensation for the consequences of a catastrophic event is consistent with the assumptions that underpin our DPP price path. No allowances were made for such events in the DPP price path.

Provisions in the Commerce Act and the IMs for claw-back

Clause 5.3.4(1) of the CPP IM states that:

> “The present value of the series of maximum allowable revenues after tax must equal the present value of the series of building blocks allowable revenues after tax less **any value of claw-back for the CPP regulatory period** …”
> (emphasis added)

Clause 5.3.4(2) of the CPP IM states that:

> "the reference to claw-back [in clause 5.3.4(1)] is a reference to claw-back, determined by the Commission pursuant to s 53V(2)(b), in the case of a CPP determination made … in response to a CPP proposal made in accordance with provisions in a DPP determination relating to the submission of CPP proposals in response to a catastrophic event."

Section 53V(2)(b) of Part 4 of the Commerce Act states that:

> "The Commission may determine any customised price-quality path that the Commission considers appropriate for a supplier that has made a proposal.
>
> … the Commission may do any of the following:
>
> (a) set a price-quality path that is lower, or otherwise less favourable to the regulated supplier, than the default price-quality path that would otherwise apply
> (b) if it sets a lower or a higher price than applied under the default price-quality path, apply claw-back …"

Neither the Commerce Act nor the CPP IM specifies the method to be used to determine the value of claw-back.

Clause 5.3.4(4)(b) of the CPP IM states that, when a CPP Determination is made in response to a catastrophic event, claw-back "will only be determined in respect of the period between the date of the catastrophic event and the date the CPP determination will come into effect."

Accordingly we have calculated a value for claw-back relevant for the period between the initial catastrophic event and the date that the CPP is expected to come into force.

Our proposed method for determining the value of claw-back

In this section, we describe how we have calculated the value of claw-back for the purposes of determining the amounts for MAR presented in Section 7.2.1. This is how we propose that the value of claw-back is determined for our CPP price path.

The initial catastrophic event occurred on 4 September 2010. The proposed CPP regulatory period will begin on 1 April 2014. Therefore the period in respect of which claw-back should be determined is 4 September 2010 to 31 March 2014. As discussed in Section 8.2, we use the period from 1 September 2010 to 31 March 2014 as a proxy for this period, because it is not possible for is to derive the required information for a partial month. As noted below, because we also include recognition of the revenues we earned over and above our costs in the first part of the FY11 year, in our claw-back calculation, this proxy has no material impact on the outcome. We determine the value of claw-back over this period, and henceforth refer to it as the claw-back period.

We determine the value of claw-back by calculating the present value, on 1 April 2014, of the difference between BBAR before tax and the actual and projected revenues received over the claw-back period. This reflects the short fall in the recovery of our costs since the earthquakes. This therefore includes compensation for the cost and revenue impacts of the earthquakes we have incurred since September 2010.

Determination of the value of claw-back

Building blocks allowable revenues before tax

The table below shows the amounts for BBAR before tax for each disclosure year in the claw-back period. It also shows the value for the period of FY11 prior to the beginning of the claw-back period. In this regard, in the following tables, FY11a refers to the period 1 April 2010 – 31 August 2010. FY11b refers to the period 1 September 2010 – 31 March 2011.

Building blocks allowable revenue ($000 nominal)	Current Period			Assessment Period	
	FY11a	FY11b	FY12	FY13	FY14
BBAR before tax	55,640	87,286	130,926	155,189	186,732

We describe how the amounts for BBAR before tax are determined in Section 7.3.1.

Actual and projected revenues

The table below shows actual and projected amounts for the revenue we receive during the claw-back period under the current DPP price path. These amounts are before tax and hence they are comparable to BBAR before tax.

Actual and projected revenue ($000 nominal)	Current Period			Assessment Period	
	FY11a	FY11b	FY12	FY13	FY14
Actual and projected revenues	62,044	74,111	124,988	136,363	139,113

The amounts for FY11 and for FY12 are actual historical revenue figures, consistent with our audited financial statements. The FY13 amount is our current forecast of revenue, based on our current prices and our current forecast for total chargeable quantities this year. The FY14 amount is our current forecast for next year, assuming average price increases equivalent to the rate of inflation, and our projected chargeable quantities.

PV of the difference

The amounts shown in the tables above are in revenue-date terms. As with the MAR calculations set out in Section 7.2.1, we convert these revenue-date amounts into year-end terms, using the timing factor adjustment term for revenue.

The table below shows BBAR before tax and actual and projected revenues, in both revenue-date and year-end terms, and TF_{rev}, for each year in the claw-back period.

Adjustments to year-end terms ($000 nominal)	Current Period			Assessment Period	
	FY11a	FY11b	FY12	FY13	FY14
BBAR before tax	55,640	87,286	130,926	155,189	186,732
TF_{REV}	1.035		1.035	1.035	1.035
BBAR before tax (year end)	57,569	90,313	135,466	160,570	193,207
Actual and projected revenues	62,044	74,111	124,988	136,363	139,113
TF_{REV}	1.035		1.035	1.035	1.035
Actual and projected revenues (year end)	64,195	76,681	129,322	141,091	143,937

We calculate the annual difference between the two year-end series, and then calculate the present value of this series, using as the discount rate the cost of debt which underlies the current DPP WACC. This use of the prevailing cost of debt is consistent with the Commission's determination of claw-back in the 2012 DPP Reset Decision for other non-exempt EDBs. We set out the cost of debt assumptions in Section 7.7.

The table below shows BBAR before tax and the actual and projected revenues, in year-end terms, and the annual difference between these amounts, for each year of the claw-back period. It also shows the present value of the annual differences at 1 April 2014.

The value of claw-back ($000 nominal)	Current Period			Assessment Period	
	FY11a	FY11b	FY12	FY13	FY14
BBAR before tax (year end)	57,569	90,313	135,466	160,570	193,207
Actual and projected revenues (year end)	64,195	76,681	129,322	141,091	143,937
Difference	(6,626)	13,632	6,144	19,479	49,270
PV of difference for FY11	8,808				
PV of difference			7,157	21,023	49,270
Total PV of difference (at 1 April 2014)	**86,259**				

*We have used the DPP cost of debt (7.93%) to discount these differences

The value of claw-back for FY11

In the calculations shown above, we determine the value of claw-back by using the difference between BBAR and actual revenue for the claw-back period. We calculate both BBAR and actual revenue for FY11 disaggregated into the periods before and after 1 September 2010 (which we use as a proxy for 4 September 2010). We use actual opex and commissioned asset data, recorded by month, to allocate the appropriate proportion of FY11 opex and commissioned asset building blocks into the claw-back period. We also used actual monthly revenue data for the purpose of determining revenue recovered in the claw-back period.

As demonstrated in the tables above, our actual revenue recovery in the claw-back period in FY11 was $13.6m below building blocks allocable revenue.

We have also considered actual revenue relative to BBAR in the part of FY11 which occurred prior to the commencement of the claw-back period. In this part of FY11 our actual revenue exceeded building blocks allowable revenue by $6.6m. It is expected that the profile of revenue and costs will differ within a financial year, due to seasonal influences (revenue tends to be higher in the winter months where as costs generally are not). In FY11, the earthquake activity caused us to incur abnormal costs from 4 September.

Given the mismatch between revenues and costs in FY11, we have reduced our proposed claw-back amount (for the period post 1 September 2010) by the amount that actual revenues exceeded building block costs in the five month period prior to the earthquakes. This is a fair adjustment, because it factors into the claw-back calculation the contributions towards the costs incurred in that year, which were earned prior to the event occurring.

The total amount to be recovered in the CPP regulatory period

We propose to recover the value of claw-back over ten years for the reasons set out in Section 7.2.1. We have allocated the value of claw-back evenly over the first and the second five-year periods – that is, we propose to recover half of the value of claw-back during the CPP period and half in the subsequent five-year period. The table below shows the value of claw-back, and the amounts which we propose to recover in each period.

Claw-back recovery ($000 nominal)		
	PV at 1 April 2014	PV at 1 April 2019
Value of clawback	86,259	
Value of clawback to be recovered in CPP period	43,130	
Value of clawback to be recovered after CPP period	43,130	57,418

Note: The rate used to derive the PV at FY19 from the PV at FY14 is the CPP cost of debt (5.89%)

As shown above, of the total value of claw-back of $86.3m, we propose to recover $43.13m (in present value terms) over the CPP regulatory period. This leaves $43.13m (in present value terms) to be recovered in subsequent years. At the end of the CPP period, the present value of the unrecovered claw-back is $57.4m.

The amounts to be recovered in each year of the CPP regulatory period

We propose to set a series for the recovery of claw-back within the CPP regulatory period which follows the same slope as MAR before tax.

As discussed in Section 7.2.1, the slope of MAR before tax is a function of the inflation rate, X factor and weighted average growth of quantities.

We have set the amount of claw-back recovery in FY15 such that the present value of the series for claw-back recovery equals the amount of claw-back to be recovered in the CPP regulatory period, and such that the amount for the recovery of claw-back in FY16 to FY19 is the result of the following formula:

$$\begin{aligned} Recovery\ of\ clawback \\ &= Recovery\ of\ clawback\ in\ preceding\ year \text{ x } (1 + inflation\ rate) \text{ x } (1 \\ &\quad - X\ factor) \text{ x } (1 + weighted\ average\ growth\ in\ quantities) \end{aligned}$$

The table below shows the calculation of the series for recovery of claw-back. It shows the inflation rate, X factor, weighted average growth in quantities, and recovery of claw-back, for each year of the CPP regulatory period.

Recovery of claw-back ($000 nominal)	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Inflation rate		2.17%	2.17%	2.17%	2.17%
X factor		-1.19%	-1.19%	-1.19%	-1.19%
Weighted average growth in quantities		0.79%	0.80%	0.85%	0.76%
Recovery of claw-back	9,175	9,560	9,964	10,389	10,822

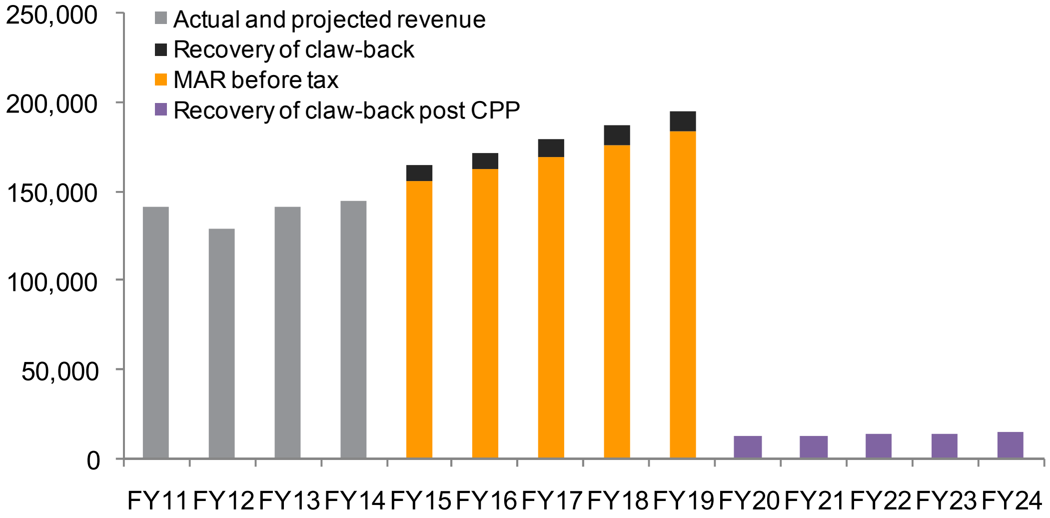
Claw-back to be recovered after the CPP regulatory period

We propose recovering the value of claw-back over a 10 year period. This means that a claw-back allowance must be included in allowable revenue beyond the end of the CPP regulatory period.

It is important however that the Commission clarifies its approach to the recovery of claw-back after the end of the CPP regulatory period. That is, the CPP Determination should specify the amount to be recovered following the CPP period, and set out the mechanism for how this will be achieved. Absent this, we will not be provided with a sufficient expectation of recovering the value of claw-back. The alternative is to recover it in full over the five year CPP period,

The chart below shows our proposed amount of claw-back to be recovered subsequent to the CPP, alongside our proposed path for allowable revenue and claw-back recovery during the CPP period. We propose that the amounts of claw-back recovery in the five years subsequent to the CPP period are specified in the CPP Determination. This is discussed further in Section 5.2.

MAR before tax plus claw-back recovery, including recovery of claw-back after CPP period ($000 nominal)



Other price path options considered

In developing the MAR set out in this proposal we considered a range of possible price paths for the recovery of building blocks allowable revenue.

In particular, we considered two variants to our proposed price path:

- recovering the value of claw-back in full over the five-year CPP regulatory period, rather than 10 years as proposed
- a lower initial price increase in FY15, followed by higher price rises in the four subsequent years of the CPP period.

Five year claw-back recovery

Spreading the recovery of claw-back over 10 years reduces the amount required to be recovered from consumers during the CPP period. While it increases the amount required from consumers in the five years after the CPP period, we think this is a beneficial trade-off which is consistent with consumer concerns about price increases. It is also more consistent with expectations for the recovery of Christchurch to span a number of years. Therefore under this approach the cost to consumers is deferred to some extent until the recovery is well under way.

If claw-back is fully recovered over five years, the price increases required in the CPP period are significantly higher, as illustrated in the following table.

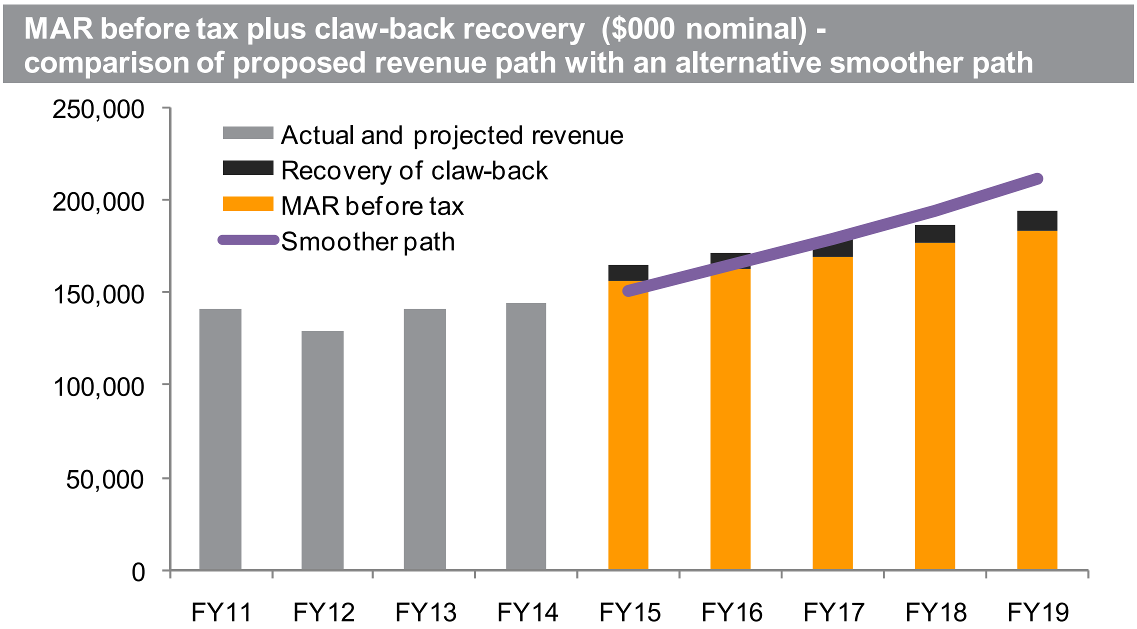
MAR including recovery of clawback ($000 nominal)	CPP Period				
	FY15	FY16	FY17	FY18	FY19
5 year claw-back recovery period	164,773	176,466	189,013	202,551	216,863
10 year claw-back recovery period	164,773	171,696	178,937	186,574	194,362
Difference	-	4,770	10,076	15,977	22,501

Note: The 5 year claw-back recovery scenario continues to assume a 15% initial price increase

Lower initial price increase

We believe that a 15% real one-off price increase followed by several much smaller increases is preferable for consumers to a smaller initial step followed by higher annual increases. The latter option steepens the slope of the price path considerably, which consequently substantially increases the maximum allowable prices at the end of the CPP.

The chart below replicates the one above which shows our proposed revenue path. It also shows the total revenue path (ie MAR plus claw-back) where the initial real price increase and those in the following four years are equalised at 5.61% per annum.



Under this scenario, prices are lower at the beginning of the CPP period, and the rate of change higher during the CPP period. Thus average prices at the end of the CPP period are considerably higher. This may lead to a reduction in prices after the end of the CPP period. We do not favour this approach as it would require material year on year increases for five years, with the potential for a price reduction in year six. We believe this is not sensible, as it creates price instability which we do not believe is consistent with the long term interests of consumers.

7.2.3 Inflation rate

Clause 3.3.1(5) of the CPP IM defines the inflation rate as the sum of forecast CPI for the four quarters of the disclosure year divided by the sum of forecast CPI for the four quarters of the preceding disclosure year, less one.

Forecast CPI is defined in Part 1 of the IMs as the forecast annual percent change in the headline CPI contained in the current RBNZ Monetary Policy Statement, or for a quarter subsequent to the forecasts provided, the arithmetic average of the values forecast in the most recent four quarters of which a forecast has been made in the Monetary Policy Statement. The Monetary Policy Statement released in September 2012 was the most current when we prepared our proposed price path, and coincides with the CPP WACC Determination. Hence we have used this data for our CPP proposal.

Inflation rate	Current Period		CPP Period				
	FY11	FY12	FY13	FY14	FY15	FY16	FY17
Inflation rate	2.91%	3.29%	1.42%	1.91%	2.17%	2.17%	2.17%

7.2.4 X Factor

The X factor is the change in real prices in year two to five of the CPP regulatory period which underlies the MAR before tax series. It is the percentage change in MAR, after removing the effect of forecast inflation and changes in weighted average quantities.

The X factor is not determined by any given inputs. It is an input itself as it, along with the initial starting position, determines the slope of the price path.

IM requirements

Clause 5.4.8(2) of the CPP IM requires that an X factor must be applied to determine the amounts for MAR before and after tax, and that a CPP proposal must state the value of the X factor.

Clause 5.4.8(3) and (4) of the CPP IM defines the X factor as that defined in Orion's DPP Determination, or a different X factor if the CPP proposal contains an explanation and supporting evidence as to why it would better meet the purpose of Part 4.

The X factor

The X factor in our current DPP Determination is 0% which was derived following consultation on the 2010 DPP Determination. This represents the Commission's view of expected industry-wide average efficiency gains to be achieved over the DPP regulatory period. We are not challenging this assumption for the purpose of the CPP. However we propose to use a different X factor because we wish to alter the slope of the price path. In order to recover our BBAR (and a portion of our proposed claw-back) we are proposing an initial step capped at 15% real, with subsequent recovery smoothed over the CPP period, using a constant X factor.

We propose to use an X factor of 1.19%. This generates a price path which involves a 15% increase in real prices in FY15, and increases of 1.19% for the next four years. As discussed in Section 7.1.3, we believe this is a price path which provides a reasonable rate of change in prices for consumers, and therefore better meets the purpose of Part 4 than the DPP X factor.

We also note that we propose an alternative depreciation method for some assets which reduces the necessary price increases in the CPP regulatory period. We discuss this in detail in Section 7.5.3.

7.2.5 Forecast weighted average growth in quantities

The slope of the series for MAR before tax is set such that real price changes are constant over the CPP regulatory period. This requires adjusting for forecast changes in quantities. We forecast weighted average growth in quantities for this purpose.

The table below shows our forecasts of weighted average growth in quantities used to determine the slope of the MAR series.

Forecast weighted average growth in quantities		CPP Period				
	FY14	FY15	FY16	FY17	FY18	FY19
Weighted average growth in quantities	0.82%	0.81%	0.79%	0.80%	0.85%	0.76%

IM requirements

Clause 5.4.8(5) of the IM requires all data, calculations and assumptions used to derive the forecast weighted average growth in quantities, including:

- a description of each demand group
- the rationale for the selection of demand groups
- the forecast growth in demand for each demand group, and the basis for those forecasts
- evidence that the forecast growth in demand for each demand group is consistent with all other relevant demand forecasts included in the CPP proposal
- the basis for the assumptions used concerning the relative proportion of fixed and variable components in the prices charged to each demand group
- a reconciliation between these assumptions and the calculation of notional revenue made pursuant to any requirement pursuant to s 53N of the Act relating to compliance with the price-quality path
- the basis of each weighting term.

We address each below.

Approach

Overview

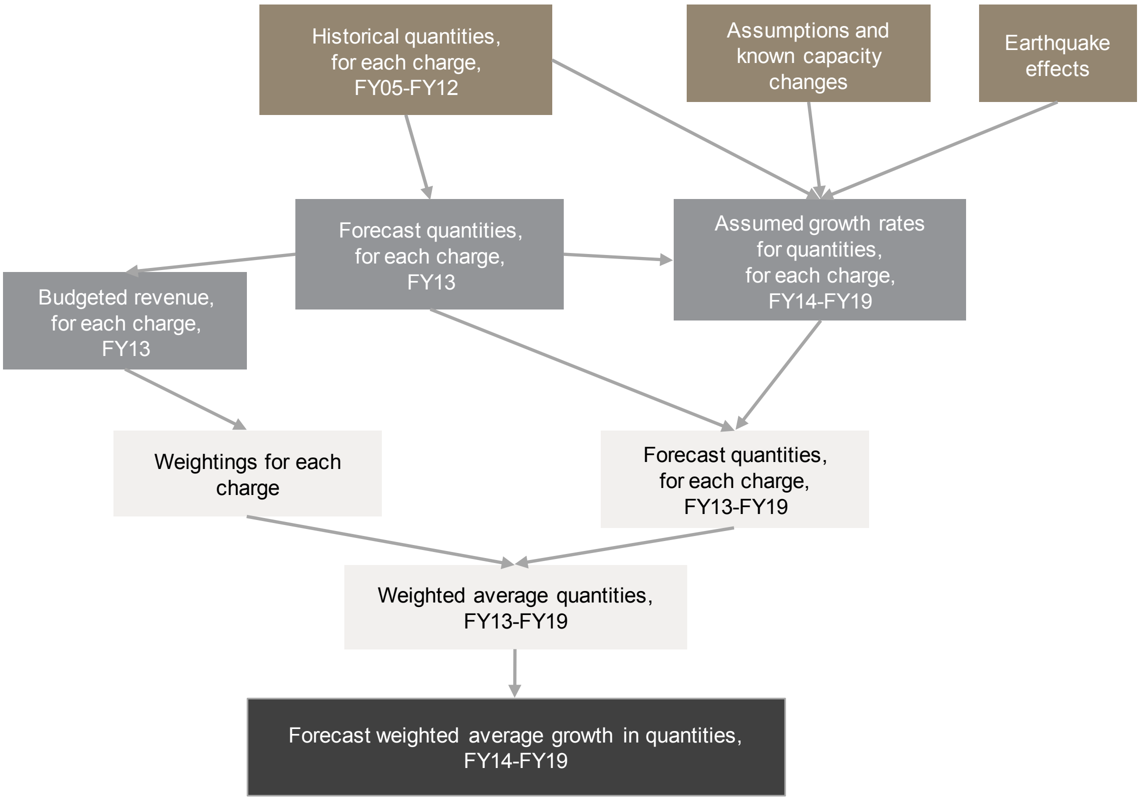
Orion has seven different groups of consumers, each of which has a different charging schedule containing multiple types of charges.

For each different charge, for each consumer group, we have developed forecast quantities for FY13 to FY19. These forecasts encompass a FY13 value, which is then projected using assumed growth rates. The assumed growth rates differ by charge based on underlying drivers. The FY13 value is a projection for the current year.

From the forecast quantities series for each charge, a weighted average quantity value for each year, from FY13 to FY19, is derived. The weights are based on budgeted revenue for FY13 by charge, as a proportion of total revenue.

From the weighted average quantities values for FY13 to FY19, a weighted average growth in quantities is derived, for FY14 to FY19.

The process described above is illustrated in the figure below.



Demand groups

IM 5.4.8(5)(a)

The CPP IM defines a demand group as a pricing category that has a discrete rate of growth in the demand for electricity distribution services over the CPP regulatory period.

For the purpose of the CPP we have specified demand groups as our connection categories (for example general, major, irrigation) and our pricing components within those categories (for example peak, volume). Potentially each of these categories and components has a discrete rate of growth.

We have the following five pricing categories:

- general (residential and small business) connections
- major customer connections (including embedded networks)
- irrigation connections
- street lighting connections
- large capacity connections.

Within the large capacity connections, there are two different consumers – Fonterra and Synlait. In addition, we have some export and generation customers.

Rationale for demand groups

IM 5.4.8(5)(b)

Our demand groups are determined based on differences in their usage of our network. They are consistent with the groups we currently use for pricing purposes. Our pricing methodology is explained in detail in the paper 'Methodology for deriving delivery prices". The most recent version is dated 3 February 2012. A copy can be found on our website at http://www.oriongroup.co.nz/publications and disclosures/pricing.

Each of general, major, irrigation, street lighting, and large capacity connections have peak demand periods at different times of the year and day. Because we have a pricing structure which charges consumers more at overall peak demand times, it is logical to set different tariff schedules for groups with different usage patterns.

In addition, the costs that we incur for major and large capacity connections are quite different to those of smaller users. It costs us less to deliver a given unit of electricity to these consumers, relative to general connections, because of the large quantities they purchase. We charge them lower unit prices as a result. Separating these customers into separate pricing categories allows us to do this. We note that we have a standard tariff schedule for major customers, while for large capacity consumers we negotiate an individual price.

Separate charges

Each demand group faces several different charges (eg fixed, volumetric, peak). For the purpose of forecasting weighted average growth in quantities, we consider the quantity for each different charge separately. Note we exclude any charges which relate to the recovery of transmission costs.

The table below lists the different charges which we currently levy on each demand group. These are reflected in our current tariff schedule, which can be found on our website at http://www.oriongroup.co.nz/publications and disclosures/pricing.

Demand groups	
Charges levied on each demand group	
General connections	**Street lighting connections**
Peak charge	Fixed charge
Volume charge: working weekdays	Peak charge
Volume charge: nights, weekends, holidays	Volume charge: working weekdays
Low power factor charge	Volume charge: nights, weekends, holidays

Major customer connections	**Large Capacity - Fonterra**
Fixed charge: standard connections	Administration charge
Fixed charge: secondary connections	Use of distribution assets
Fixed charge: dedicated equipment	**Large Capacity – Synlait**
Peak charge	Administration charge
Capacity charge	Asset charge
Irrigation connections	**Export and generation**
Capacity charge	Real power distribution component
Volume charge: working weekdays	Reactive power distribution component
Volume charge: nights, weekends, holidays	Generation credits
Rebate: power factor correction	
Rebate: interruptibility	

Demand group forecasts

IM 5.4.8(5)(c)and (d)

In the remainder of this section we set out our forecast quantities for each demand group and charge type and the basis for those forecasts.

Historical quantities

In order to help derive the forecast quantities for each charge, historical data has been compiled as follows:

- actual chargeable quantities for each charge for FY10 to FY12
- estimated quantities for years prior to FY10 due to our adjustments to our charging basis which were introduced at the start of FY10. For some charges the quantities before FY10 do not directly correspond to the charges which have applied thereafter. Therefore, using the same approach we have used to demonstrate compliance with the DPP, we adjust the pre-FY10 chargeable quantities to match our current charging basis (from FY05).

Our actual and estimated historical quantities, from FY05 to FY13, for each of the current charges for each consumer group, are shown in Appendix 12.

Forecast FY13 quantities

We use several different approaches to forecast the FY13 quantities. The method used depends on the charge. Across our charges and demand groups, we use a combination of the following methods:

- extrapolation of a linear trend over the previous five years
- adjustment to the extrapolation of a linear trend, due to earthquake effects
- use of FY13 year-to-date actual values
- use of FY12 quantities historical averages
- introduction of new charges.

In the following table, we state the method used for each charge, and the relevant forecast FY13 quantity for each charge. We set out the rationale for each method used below.

Forecasting FY13 quantities

Consumer group and charge type	Unit	Forecast method used	Forecast FY13 quantity
General connections			
Peak charge	kW	FY13 YTD quantities billed	475,925
Volume charge: working weekdays	MWh	Adjusted 5-year linear trend	1,000,022
Volume charge: nights, weekends, holidays	MWh	Adjusted 5-year linear trend	1,158,986
Low power factor charge	kVAr	Same as FY12	0
Major customer connections			
Fixed charge: standard connections	connections	FY13 YTD connections billed	357
Fixed charge: secondary connections	connections	FY13 YTD connections billed	14
Fixed charge: dedicated equipment	by item $000	FY13 YTD quantities billed	1,628,574
Peak charge	kVA	FY13 YTD quantities billed	89,667
Capacity charge	kVA	FY13 YTD quantities billed	197,105
Irrigation connections			
Capacity charge	kW	Same as FY12	70,446
Volume charge: working weekdays	MWh	5-year linear trend	59,723
Volume charge: nights, weekends, holidays	MWh	5-year linear trend	103,188
Rebate: power factor correction	kVAr	5-year linear trend	28,555
Street lighting connections			
Fixed charge	connections	5-year linear trend	43,248
Peak charge	kW	5-year average	2,352
Volume charge: working weekdays	MWh	5-year linear trend	3,252
Volume charge: nights, weekends, holidays	MWh	5-year linear trend	22,504
Fonterra			
Administration charge	kVA	New charge	4,500
Use of distribution assets	kVA	New charge	4,500
Synlait			
Administration charge	kVA	Same as FY12	5,800
Asset charge	kVA	Same as FY12	5,800
Export and generation			
Real power distribution component	kW	2-year average	2,377
Reactive power distribution component	kVAr	2-year average	1,419
Generation credits	kWh	Known generation credit customers at 100% reliability	256,000

Our default method is to extrapolate a five year linear trend out to a sixth year. The FY13 value is forecast by constructing a linear trend line of the values for the five years from FY08 to FY12 and projecting this line forward one year. Historical quantities for each charge are set out in Appendix 13.

In our view this is a sensible approach to forecasting quantities which vary around a general long-term trend. The majority of our quantities behave like this, at least over a period of around five years.

Below we discuss our method for charges where we do not think that this approach is appropriate.

Adjusted linear trend due to earthquakes

General consumer historical demand, shows a slowly increasing trend since FY05, with usage falling after the earthquakes. We have interpreted this as a step-change in usage. We have assumed that the ongoing growth rate will remain (from a new lower level), as opposed to a reduction in the annual rate of growth.

A trend line using actual values from FY08 to FY12 produces a linear path which is below the values immediately prior to the earthquake, and then above those after. Accordingly a linear path is not appropriate for general consumer volumetric charges.

Instead, we construct a linear path where we use for the FY12 figure our original projection (which is significantly higher than the actual), which in effect shows the path we were projecting before the earthquakes. Then the FY13 forecast is determined using this linear path, after adjusting it downwards by 7% (which is our estimate of the stepped reduction in load due to the earthquakes). This moves the linear path down, to a lower parallel path, by 7% of the FY13 value.

A similar argument could be made for some of the other charges for which we have used the simple linear trend. However we have developed alternative approaches which address, where relevant, the impacts of the earthquakes. For example, FY13 YTD actual figures are used for general connections peak demand and for all major customer connections. In addition the earthquakes had very little impact on irrigation and street lighting connections.

FY13 actual quantities

Where possible we have used actual YTD values from FY13 to inform our forecasts, however in most cases this is not possible because the YTD values do not give us enough evidence to develop a robust estimate. For major customer connections, forecasts for all charges are based on FY13 YTD values. It is assumed that there will be no new connections or new dedicated equipment during the remainder of FY13 (ie all chargeable connections are already connected). It is also assumed that the YTD peak demand and capacities will be the final year values because we have completed the winter period.

We also use the FY13 YTD value for the peak demand for general consumers. This is our largest charge in terms of the total revenue collected and therefore it is subject to less variability over time than for smaller connection groups. Furthermore, as with major customers, we believe that the peak demand patterns shown in FY13 so far will not materially change during the rest of the year. We therefore assume that the YTD peak demand will be the final year value.

FY12 quantities

For some charges, it is assumed that the quantities in FY13 will be the same as the quantities in FY12. In particular, this assumption is used for the capacity for irrigation connections (kW) and the two charges for Synlait (both in kVA).

For irrigation customers, we expect that there will be some new irrigators connecting but that some will opt out as retailers change their pricing structures. We expect similar capacity in the future, despite projecting continuing increases in total usage.

Synlait has indicated they will have similar loading in FY13 as they had in FY12.

It is also assumed that there will continue to be no general customers affected by the low power factor charge.

Historical average

For peak demand for street lighting, and for the power distribution components of export and generation connections, historical values do not show a noticeable trend, but rather vary according to other factors.

For these charges, we use an historical average rather than extrapolating using a time based trend. Street lighting peak demand is variable, so we use an average over the last five years, whereas the export and generation charges are less variable so we use a two-year average.

New charges

FY13 is the first year in which we are charging dedicated charges to Fonterra separately. We base our forecasts on the estimates used at the time the charges were set.

Forecast FY14 to FY19 quantities

We base our forecast growth rates for each charge component on historical trends, external forecasts and consideration of the effects of the earthquakes. We describe the forecasts for each charge type below. Our underlying forecasting assumptions are described at the end of this section.

General, irrigation, and street lighting connections, and Synlait

For general, irrigation and street lighting connections, and for Synlait, the values for FY14 to FY19 are forecast by applying a percentage annual growth rate to the FY13 quantity. The assumed annual growth rates are shown in the table below.

Forecasting assumptions

General, irrigation, streetlighting and Synlait consumer groups	Unit	FY13 Quantity	Annual growth rate (FY14 to FY19)
General connections			
Peak charge	kW	475,925	0.80%
Volume charge: working weekdays	MWh	1,000,022	0.80%
Volume charge: nights, weekends, holidays	MWh	1,158,986	0.80%
Low power factor charge	kVAr	0	0%
Irrigation connections			
Capacity charge	kW	70,446	1.33%
Volume charge: working weekdays	MWh	59,723	1.33%
Volume charge: nights, weekends, holidays	MWh	103,188	1.33%
Rebate: power factor correction	kVAr	28,555	1.33%
Rebate: interruptibility	kW	42,067	1.33%
Street lighting connections			
Fixed charge	connections	43,248	1.00%
Peak charge	kW	2,352	-0.63%
Volume charge: working weekdays	MWh	3,252	-0.63%
Volume charge: nights, weekends, holidays	MWh	22,504	-0.63%
Synlait			
Administration charge	kVA	5,800	0%
Asset charge	kVA	5,800	0%

For each consumer group included in the above table:

- general connections: we expect that recent small growth rates will continue. It is assumed that there will be 0.8% growth both in peak and consumption each year from FY14 to FY19
- irrigation connections: we experienced relatively high growth in capacity between FY05 and FY10. Since that time this has slowed. This is illustrated in a chart included in Appendix 12. We expect that growth over the period to FY19 will be more like that experienced over the last two years as the dairy conversion rate (which generates the majority of the irrigation demand) has peaked. The average annual growth rate in chargeable capacity (kW) in the two years from FY11 to FY12 is 0.99%. This is assumed to apply for irrigation customers from FY14 to FY19. It is also assumed that irrigation consumption and associated rebates will grow at the same rate
- street lighting connections: our growth assumptions are based on our expectation that recent trends will be maintained over the period to FY19. Since FY08, the number of connections has increased by an average of 1.0% annually. In contrast, consumption has fallen since FY08, by an average of 0.63% each year. Charts in Appendix 12 show the historical number of streetlight connections and associated chargeable volumes. It is assumed that connections will continue to increase, by 1.0% each year, and that chargeable volumes will continue to decrease, by 0.63% each year from FY14 to FY19. Lastly, it is assumed that peak demand falls at the same proportional rate as chargeable volumes over this period
- large capacity - Synlait: we are not expecting any increase in capacity over the projection period. It is therefore assumed there will be zero growth in kVA from FY14 to FY19.

Large capacity - Fonterra

For Fonterra, the FY13 quantity is 4,500 kVA (it applies to both charges). It is assumed that it will increase to 9,000 kVA in FY14, and then remain constant at this level to FY19.

This is based on a planned upgrade to Fonterra's connection to occur in FY14. This planned upgrade is expected to approximately double Fonterra's capacity. There are no further upgrades planned for in the CPP period.

Major customer connections

For major customer connections, we do not expect that quantities will grow proportionally each year to FY19 (as we do for general customers). We expect that the demand from our major customers will be somewhat variable, reflecting a range of earthquake recovery plans which will involve for some, rebuilding their businesses. We note that a number of large connections have been or are to be demolished in the CBD. Others have suffered damage and or economic effects, in particular inaccessibility.

However, we believe that underlying small growth exists for new connections, some of the destroyed connections will relocate and others will be replaced by new equivalents (for example CERA's anchor projects in the CBD). Our approach to deriving this forecast has been to assess each major connection on a case by case basis, to estimate to what extent they are expected to rebuild or relocate where necessary.

Accordingly we estimate that we will connect/reconnect major customers each year to FY18, with a corresponding increase in kVA and dedicated equipment. This recovery phase is expected to be completed by FY18.

The table below sets out our estimates of the annual increase in quantities, for each type of charge in relation to earthquake recovery.

Forecasting assumptions

Major customer connections	Units	FY14	FY15	FY16	FY17	FY18	FY19
Fixed charge: standard connections	connections	6	5	5	8	3	0
Fixed charge: secondary connections	connections	0	0	0	0	0	0
Fixed charge: dedicated equipment	by item $000	16,400	15,802	8,720	12,955	31,858	0
Peak charge	kVA	1,092	795	358	829	993	0
Capacity charge	kVA	1,985	1,913	1,055	1,568	3,856	0

Export and generation

It is assumed that the quantities for export and generation consumers increase at the same proportional rate as the capacity charge kVA quantities for major customer connections.

Basis of forecast growth assumptions

IM 5.4.8 (5)(d)

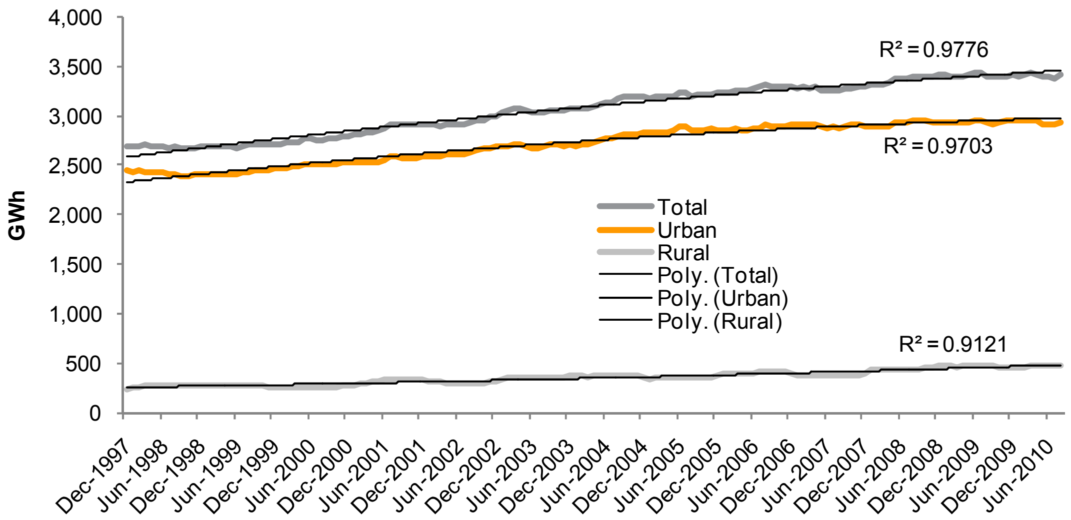
In this section, we provide background information regarding our assumptions underpinning our forecast quantities with particular emphasis on the impact of the earthquakes.

Historical Growth

While not necessarily the best measure of network usage, nor our main cost or investment driver, delivered energy volumes are a good overall indicator of growth in what consumers actually want – energy. Our key chargeable quantities are predominantly volume based, or at least strongly correlated with volumes, over the medium term. For example for the FY12 year our delivered energy volumes were around 350GWh or 10.3% below budget, while our delivery revenue was $21m or 10.5% below budget.

The following graph shows trends in the volumes delivered at GXPs from 1997 up until the end of August 2010, immediately prior to the first major earthquake. The volumes are rolling twelve month totals which remove the seasonality and most of the variability in monthly volumes.

GXP volume analysis rolling 12 month GWh Jan 97 to Aug 10 (excludes embedded injections)



Volumes are shown in total and also divided into urban and rural (Springston and Hororata GXP) areas. Over the period volumes grew at 1.8% per annum in total. This reflected average annual growth rates of 1.3% in the urban area, and 5.8% in the rural area. The greater growth rate in the rural area is largely attributable to significant growth in irrigation, driven in particular by dairy conversions. Growth in the urban area, and therefore overall, has slowed somewhat over the last few years. Growth in irrigation has also slowed in recent years due to the rate of dairy conversions slowing down.[11]

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[11] Refer Canterbury Irrigation Peak Electrical Load – Spatial Pattern across Distribution Networks, Donaggio and Bright, 2011, ARL Report C10083/1, prepared for Transpower NZ Limited. In particular the executive summary, page 2, which suggests growth in irrigation peak demand in the Orion area of 11% over the next 5 to 7 years.

The trends shown here are second order polynomials, which capture better the drop off in growth overall in recent years, than a linear fit (as measured by R2).

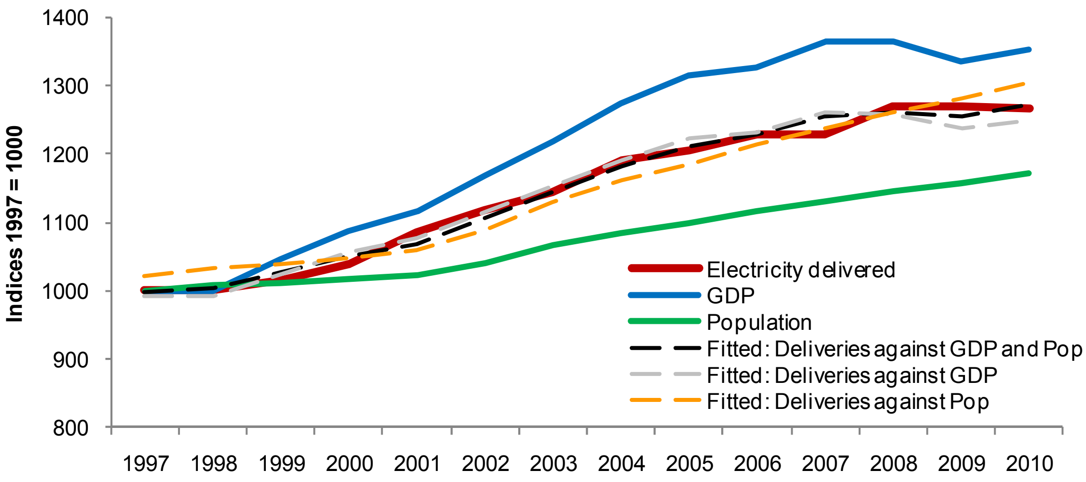
Growth drivers

Demand for electricity is derived demand, in that consumers do not use electricity directly, but use it for useful services, such as heating, lighting, and running machines and appliances. As such, growth in electricity demand is largely driven by a combination of the number of connections, and the nature of those connections.

The first of these is reasonably easy to measure, the second not so much. However, we consider that it is fair to assume that the nature of connections will change only slowly, on average, although some types of connections, particularly businesses, may reflect shorter-term changes in economic conditions.

The following graph shows the (pre-earthquake) relationship between electricity volumes, Canterbury (CCC and SDC areas) population numbers[12] (which are themselves strongly correlated with connection numbers) and real GDP,[13] leading up to the earthquakes. Over the period NZ wide GDP growth averaged 2.3% per annum, while Canterbury population growth averaged 1% per annum. We note that Statistics NZ population projections (produced pre-earthquake in 2009[14]) for the Canterbury area were slightly lower than the historical growth rate: 0.9% per annum for 2012 to 2016, and 0.7% per annum for 2017 to 2021.

Delivered volumes / GDP / population analysis 1997 to 2010



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[12] Sourced from Statistics New Zealand, Infoshare: Estimated Resident Population for Territorial Authority Areas

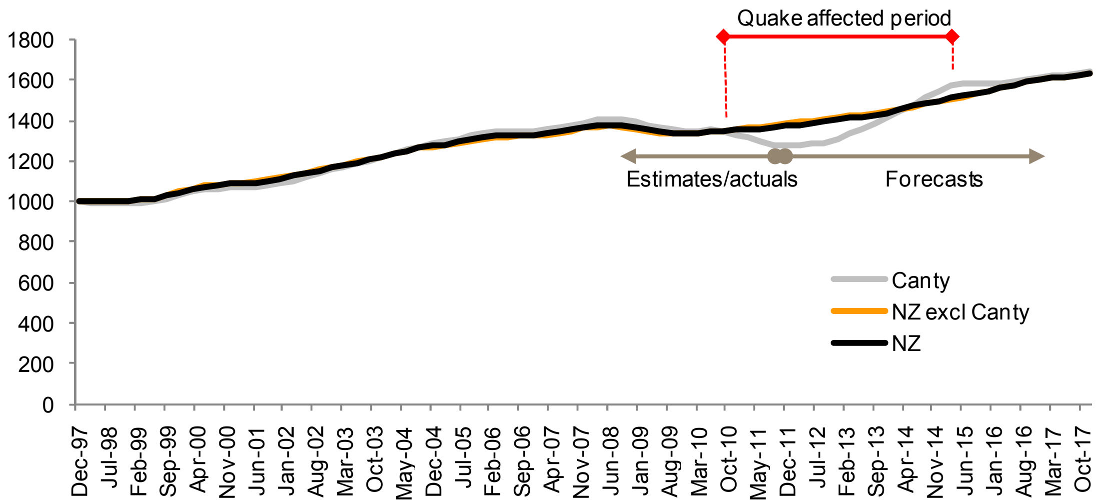
[13] Sourced from Statistics New Zealand, Infoshare: Production, GDP and GDE, Market Price, Seasonally Adjusted Quarterly

[14] See http://www.statistics.govt.nz/tools_and_services/tools/TableBuilder/population-projections-tables.aspx#subnational

It is reasonable to assume that, had there not been any earthquakes, growth in energy volumes would have continued at between 0% and 2% per annum, consistent with economic and population growth.

We note that electricity volumes have grown a little faster than population, and a little slower than GDP, over the last 15 years. Both GDP and population can be used to "explain" growth in electricity volumes reasonably well, and the graph above shows "fitted" volumes (using linear regression) using three models: GDP and population, GDP alone and population alone. All are reasonable fits, with GDP and population being the best model, (measured by R2). Note this is NZ wide GDP. The following graph shows that (pre-earthquake) Canterbury GDP has followed NZ GDP very closely.

Infometrics Estimates and Forecasts of GDP (Qrtly indices (Dec 97 = 1000) Seasonally adjusted)



The above graph shows Infometrics'[15] estimates and forecasts (prepared in February 2012) of Canterbury and NZ GDP, with the Canterbury forecasts showing the earthquake impact (down and then up) continuing through to early 2016. The forecast includes a period of over-shooting where Canterbury GDP is higher than would have been expected pre-earthquake, after which growth once again is forecast to closely align with NZ wide growth.

GDP and population are not independent (of each other) variables,[16] so care must be taken in using both in any analysis or forecast. However GDP does seem to explain the drop off in growth in delivery volumes over the last few years.

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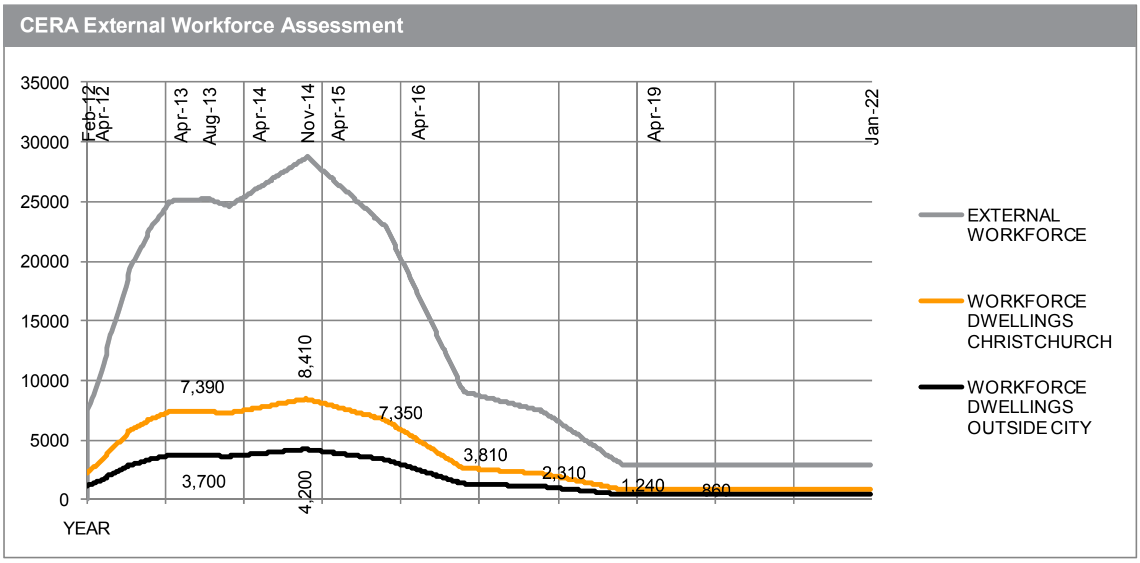
[15] Procured by private subscription in June/July 2012

[16] Technically they display strong multi-collinearity. The correlation between the two is around 0.97, and adding either variable to the regression changes the coefficient of the other variable dramatically, while not improving the R2 of the regression by much.

The forecasts indicate a faster growth rate for Canterbury than NZ through to March 2015. The forecasts do not include information by industry, but it seems reasonable to assume that stronger growth in the recovery period will be driven by construction activity. Discussion with Infometrics has confirmed this. Construction itself is not a particularly energy intensive sector, but it is predicted that a substantial temporary construction workforce will migrate to Christchurch over the next few years. The following graph shows CERA's temporary workforce projections and associated dwellings.



CERA External Workforce Assessment

We do not consider that the temporary workforce will have the same impact on energy consumption as a permanent workforce, because such a workforce brings with it fewer dependants, and uses different accommodation. However the numbers are sufficiently large that it is reasonable to assume that there will be some impact above and beyond normal growth. This impact is difficult to estimate.

It is noteworthy that the pattern and timing of growth in the temporary workforce is similar to the period of stronger than normal economic growth forecast by Infometrics as shown in the graph on the previous page. We also note CERA estimates that a significant proportion (more than two thirds) of the temporary workforce is already present in Canterbury (as illustrated above).

Accordingly we assume that any influence on electricity demand will already be present. We also note that it is likely that the temporary workforce may also offset to some extent the reduction in tourist numbers and other short term visitors to Canterbury since the earthquakes. This impact has been reported in the media as a reduction of approximately 20% or 100,000 visitors per year as a result of the earthquakes.

More importantly, the greater Christchurch urban development strategy (UDS) partners commissioned Market Economics[17] to develop projections of changes in the patterns of growth in household numbers in the light of the earthquakes. We do not reproduce this analysis in any detail here, but in summary the report for UDS modelled four possible impact and recovery scenarios – 'Rapid', 'Quick', 'Moderate' and 'Slow' – in the number of households. These are in descending order of post-earthquake rate of growth.

The report itself does not identify a most likely scenario. However the CCC Monitoring unit in a memo summarising the report recommends using the "Quick" scenario.[18] This scenario can be summarised as follows:

- initial loss of 2.5% of households in CCC, and no change in SDC by the end of 2012. This equates to an approximate 2% loss within our network area (Statistics NZ has earlier estimated a 2% population loss from the earthquakes, which is consistent with this)
- growth through to 2016 at a much slower rate than pre-earthquake forecasts in the CCC area, but faster in the SDC area. This translates to an overall increase (from the lower post-earthquake base) in the Orion area of 0.6% per annum through to 2016, and then 1% per annum from 2016 to 2021. These overall growth rates are slower than those predicted pre-earthquake.

Overall the two key drivers of electricity demand are forecast to show somewhat different patterns of growth during the recovery period. What we cannot say with confidence is that the historical relationship between electricity demand and those drivers will continue into the future. In particular we do not think it is reasonable to expect electricity demand to exceed pre-earthquake forecast levels at any point with the retirement of significant areas of the city and the associated connections. It is therefore reasonable to assume that, following the recovery period (of up to five years) electricity demand will recover to a level lower than it would have been (at any particular future date) in the absence of the earthquakes. In order to quantify the impact we have assumed:

- that the UDS predictions are the best guide available for growth pertaining to our general connections category
- a permanent reduction in volumes associated with major customer connections that will not be rebuilt (as a result of CERA planning decisions) of 30GWh per year, or 1%

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[17] Greater Christchurch Household Scenarios 2011-2041, March 2012. The UDS partners are: Ngami Thai, NZTA, Environment Canterbury, SDC, CCC and Waimakariri District Council.

[18] Memo dated 13 March 2012 entitled 'Summary of Post Earthquake Growth Projections for Christchurch City at March 2012', by the CCC Monitoring and Research Team which states on page 2: 'At this point in time there is so much uncertainty around population change post earthquake, especially in the next 5 years. What we recommend is using the quick BAU scenario, but taking into account the range of the other scenarios when assessing risk and the range of possible outcomes throughout the City.'

- a further permanent reduction in volumes associated with non major customers in the same area of 20GWh per year. We note that it is expected that new CBD connections will have lower electrical density.

Taken together these factors suggest that electricity demand will not recover much over the CPP period. A number of the major projects in the CERA CBD plan show completion dates around the end of calendar 2016 (and so will have their first notable impact on Orion's revenue in FY18). For population and households, the "Quick" scenario suggests a widening gap between pre- and post-earthquake forecasts over the CPP period.

The way this has been reflected in the modelling of quantity growth is that we have assumed that:

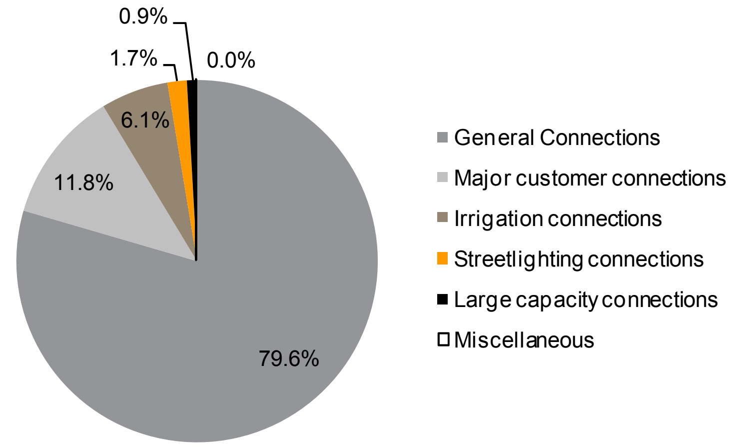
- recovery assumptions have no effect on the demand groups categorised as unaffected by the earthquakes
- for major customer connections our case by case analysis assumes a time frame of rebuild activity through to FY18
- for general connections, growth from the current position is assumed to occur at the rate of dwelling growth as set out in the Quick UDS scenario.

As noted by the CCC, there is considerable uncertainty around any approach that compares what might happen with what might have been. This is particularly true for general connections when they make up such a significant proportion of our revenue.

Revenue composition

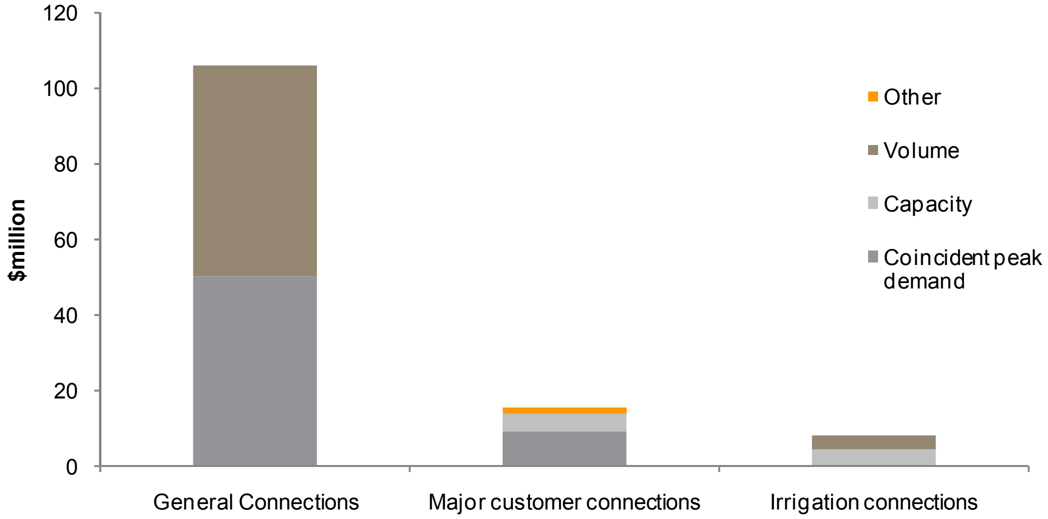
The following graph shows the breakdown of Orion's budgeted distribution revenue for the FY13 year. It can be seen that by far the bulk of revenue (around 98%) comes from the three main connection categories (general, major and irrigation) and that the general category dominates overall.

Orion distribution revenue by connection category (FY13 budget)



The following graph shows the further breakdown of revenue into charge components for the three main categories.

Orion distribution revenue by component within main connection categories (FY13 budget)



Note that while some component classifications in the graph apply to more than one category, they are not always exactly the same thing. However the bulk of Orion's revenue comes from chargeable quantities that are driven by consumption. The difference between consumer groups is predominantly the period over which consumption is measured, as follows:

- volume based revenue consumption is measured over the whole year
- coincident peak demand is measured over the 100 or so hours of highest Orion network demand
- major customer assessed capacity is measured using the top 12 demands from each site.

Trends in chargeable quantities

As noted above, the growth rate in delivered energy volumes appears to have slowed a little over recent years (pre-earthquake), and has been below the longer term average growth rate of 1.8% per annum. Over the five years to January 2011 the growth in delivery volumes averaged around 1.2% per annum.

Energy, capacity and demand growth

Quantity	Growth rate % p.a
Energy delivered at GXPs	**1.20%**
General connections peak demand	0.40%
General connections volumes	0.40%
Irrigation capacity	1.00%
Irrigation volumes	1.00%
Major customer assessed capacity	(0.60%)
Major customer control period demand	(0.60%)

It can be seen that these key quantities show relatively low growth rates compared with overall growth, but it must also be noted that these are only used for projecting one year ahead. While our normal pricing process focuses only on the year ahead, we provide high level estimates for Orion's five-year financial forecasts. In our five year forecasts prepared in February 2011, an annual quantity growth rate of 1% per annum was assumed for FY13 through to FY17.

Graphs showing recent trends in quantities are included in Appendix 12.

We have not previously had a method for projecting individual chargeable quantities over a period as long as the five year CPP. Hence our approach for each demand group is to use our best estimate of underlying growth in each group, and then where appropriate, modify this for earthquake effects. Because there is no historical information available on earthquake effects, this process requires some judgement, and hence is inherently uncertain.

Earthquake impacts

How the earthquakes impacted revenue quantities

Each of the major earthquakes since September 2010 has had some effect on electricity demand and revenue.

The September 2010 earthquake was certainly a significant event at the time, but supply was restored very quickly, mostly the same day. In addition the earthquake had no effect on a key component of our revenue (general connection peak demand) as this had already been set in the period May to August 2010. It also had no effect on major customer chargeable quantities, which are not revised until the following year (and in any case were not materially affected).

Thus the only noticeable effect of the September 2010 earthquake was on general connection volume chargeable quantities, and being a weekend[19] only a small amount of revenue was lost on the days when the impact was greatest. The total revenue impact in the FY11 year was estimated in September 2010 at $450k, which was about 0.2% of annual delivery revenue. The ongoing effect was estimated as being even smaller, just $150k in FY12.

However the February 2011 earthquake was more significant, creating the residential red-zone, and closing off the centre of the city (the CBD red zone), much of it to this day. The reason there has been such an enduring effect on Orion's business is that, despite the network being more or less completely restored within a few months of the February earthquake, (though with much less resilience), the properties that connect to it have not been. There are a number of ways to consider this impact, but some key observations are:

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[19] The volume charges are structured so that the price at nights and at weekends is much lower than during weekday days: less than 1 cent per kWh versus more than 6 cents per kWh during working weekdays.

- around 6,500 residential red zone properties have been or will be abandoned by June 2013, based on current planning. Note there are 1,000 or so red zone properties that are outside the Orion network area
- insurers are addressing about 21,000 major repairs or rebuilds over the EQC $100k cap
- at least 1,100 properties in the CBD have been or will be demolished, including some of the largest buildings (and biggest energy users pre-earthquake) in Christchurch.

We estimate that delivery revenue (and gross margin) for FY11 took a further $2m hit as a result of the February earthquake, due to reduced general connection volumes, for the remainder of that financial year. Delivery revenue for the FY12 year was $21m below (pre-earthquake) budget. Our cost of sales (mainly transmission) did not change as a result of the earthquakes, but our prices had already been set. Accordingly, we have significantly under-recovered transmission costs in the FY12 year.

Indicators

The following set of graphs and tables show the impact of the earthquakes on energy volumes and other related electricity indicators.

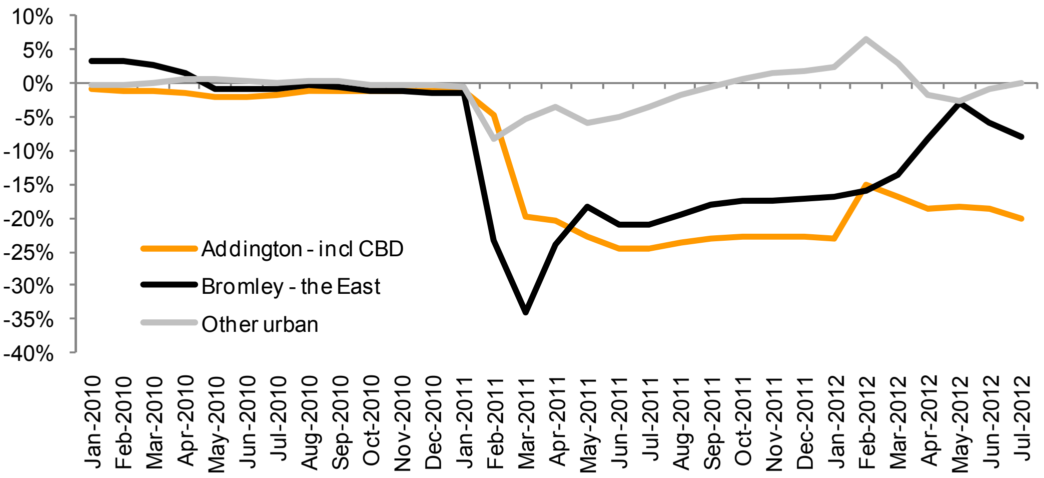
As noted above, across the whole network, volumes in FY12 were around 10% below budget, with the revenue impact being very similar and around $21 million. The following table shows a breakdown of the main contributions to this revenue reduction.

Earthquake impact on revenue

Charge type	Budget ($m)	Actual ($m)	Revenue impact ($m)
General connection peak (MW)	482	449	(5)
General connection volumes (GWh)	2,534	2,289	(8)
Major customer assessed capacity (MVA)	228	199	(2)
Major customer peak (MVA)	122	106	(2)
Total			**(18)**

We do not budget at GXP level, but post earthquake volumes can be compared with pre-earthquake volumes at each GXP. The following graph shows how the volume effect occurred mainly on the Bromley and Addington GXPs, which respectively supply the worst damaged eastern suburbs and the severely damaged and still largely off-limits (or now demolished) CBD. Note that the data reflects some switching of supply between GXPs, particularly Bromley and “other urban”. As of the most recent months in the series, this is no longer occurring.

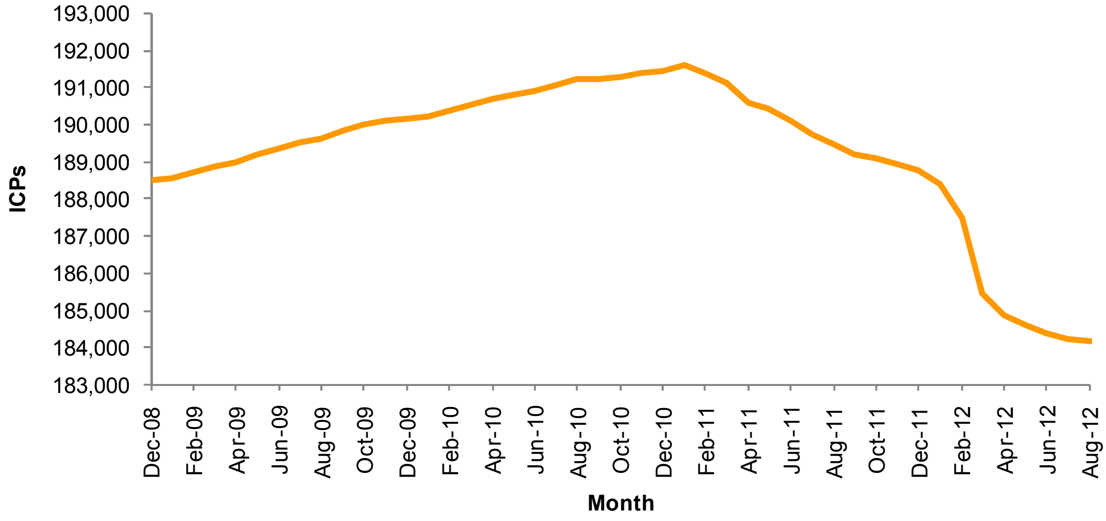
GXP volume analysis - earthquake impact
Cumulative % variation from same month previous year (or two years before)
Jan 2010 to Jan 2011, Feb 2011 to Jan 2012 and Feb 2012 to Jul 2012



Overall network volumes are estimated to still be significantly (7%) less than historical (pre-earthquake) volumes. Allowing for the growth that would have occurred had there the earthquakes not occurred, this suggests volumes overall remain about 8-9% less than they would have otherwise been.

The following graph shows changes in the number of connections each month over the last few years. The significant reduction (by about 7,000 or 4%) since the February 2011 earthquake reflects a combination of connections that have been de-energised (supply fuses removed, most likely because they are badly damaged or abandoned) and those that have been decommissioned (permanently disconnected from the network, usually as a precursor to demolition). It is also noteworthy that had there not been earthquakes we would have expected there to have been continued growth to around 193,000 energised connections by now. The decline in the series appears to be bottoming out.

Connected (Energised) ICPs as at End of Month



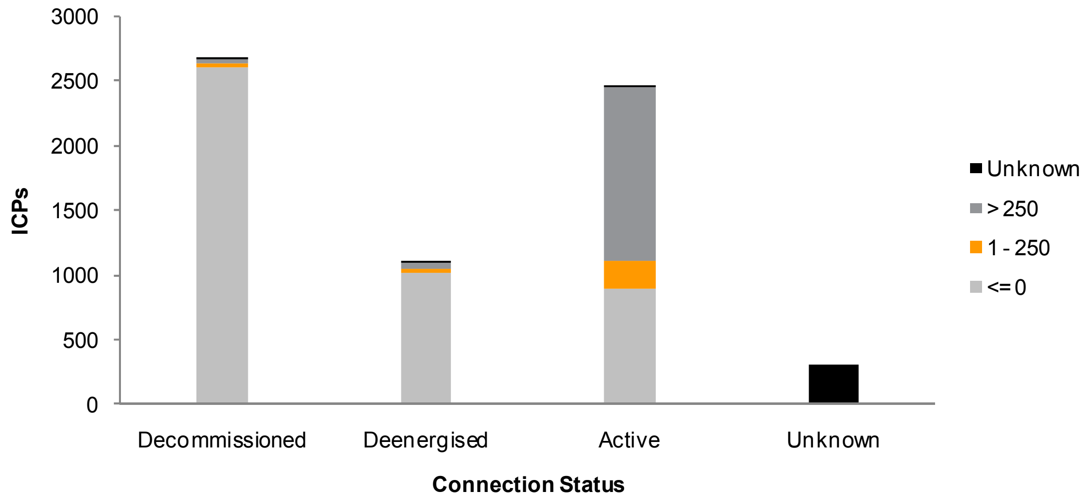
Again the reduction has been at Bromley and Addington GXPs with connected ICPs at those two GXPs falling by over 8,000 (9%) offset by increases in other areas of around 1,000 (or 1%).

A subset of the Bromley group in particular is the CERA residential red-zone, where in due course all of the 6,500 or so connections will eventually be abandoned. The following table and graph shows the status (as at mid July) of the residential red zone connections. The table and graph show connection counts by connection status, and by monthly consumption range in kWh (using retailer data). It can be seen that at least half have already been abandoned (the decommissioned and de-energised connections) while a further 886 appear to be using little or no energy, suggesting no occupancy. On the other hand, around 1,500 appear to still be using reasonably significant amounts of energy.

Note that not all residential red zone properties are badly damaged, the red zoning is mainly about the effects on the land in the wider area. Also note there are some obvious inconsistencies in the data, for example a decommissioned connection should not have any associated volumes. We suspect these inconsistencies, which do not detract from the overall picture, are a consequence of the disruption to normal business processes between customers, retailers and Orion. It will take some time for all of the data to catch up with the physical reality at every connection. In the following table 'Unknown' refers to a combination of not being able to match CERA's address data, and not having any consumption data (not all retailers provide it to us).

Connection Status	<= 0	1 – 250	> 250	Unknown	Total
Decommissioned	2,607	32	25	2	2,666
De-energised	1,021	28	48	1	1,098
Active	886	222	1,338	14	2,460
Unknown	0	0	0	304	314
Total	**4,514**	**282**	**1,411**	**321**	**6,528**

CERA Red Zone ICPs by Connection Status



Where did the volume go?

By 1 April 2011, our network was pretty much fully available to anyone that wanted it, and the June and December earthquakes had no material additional impact. Yet volumes for FY12 were around 10%, or 330GWh, below budget. It is useful to consider where this volume went, particularly since it is much bigger than the estimated population impact, which is a reduction of nearly 9,000 or around 2%.[20] The following table attempts to reconcile the overall impact with known and estimated components. As can be seen there is some volume unaccounted for.

Source of reduced volumes

Source	**GWh**	**Comment**
Overall reduction	330	
Reduction in rural area	60	Unlikely to be earthquake related. Mainly down in summer of 2011/12: winter 2012, winter 2011 and winter 2010 more or less the same. Probably driven mainly by wet irrigation season. Irrigation volumes are very volatile from year to year. No reduction in the number of energised connections for rural GXPs, so no indication of permanent earthquake related damage. No reduction in irrigation capacity
Major customers – 60 or so no longer operating	90	Most of the 60 or so are in the CBD red-zone. Many have since been demolished (eg Crowne Plaza, Grand Chancellor, Convention Centre), most of the others are still off limits and cannot operate (eg Rydges and Millennium). A few have reopened (eg Ballantynes, The (new) Press building). 60 connections is roughly 15% by number, they took with them a similar proportion of Major's volume, and about 12% of chargeable capacity/peak demand
Major customers – operating but volume reduced	10	There are lots of overs and unders: this is the net
Half hourly metered (but	7	22 connections at an average of 335MWh/yr

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[20] See: http://www.stats.govt.nz/browse_for_stats/population/estimates_and_projections/SubnationalPopulationEstimates_MRJun11.aspx. This refers to a reduction of 8,900 or 2.4% in Christchurch City. The Orion network are includes Selwyn District Council as well, which did not see the same sort of reduction, and hence the lower percentage used above.

not major) CBD customers		
“Abandoned” general connections - Bromley	50	4,000 (net reduction in energised connections all GXPs except Addington) at 13MWh/yr mainly homes in the eastern suburbs, including residential red-zone
“Abandoned” general connections (NHH) – Addington (CBD)	60	3,000 (reduction in energised connections) at 22MWh/yr mainly businesses in the CBD
Unexplained	53	

Normal year on year variations are in the range of +/- 2%, after allowing for underlying growth. 10% is unusual.

Current status

As noted above, we estimate that electricity delivery volumes are still around 8-9% lower than they otherwise would have been.

As also shown above there is some way still to go in the residential red zone in terms of people actually vacating properties. CERA’s settlement deadline for most is now June 2013. It is reasonable to assume that most of those leaving relocate within the network, but even if they all left permanently that would only reduce volumes by around 15GWh per year.

Also of relevance are our budget projections for the FY13 year, and how they compare with the previous year’s projections, which were prepared pre-earthquake. The following table summarises the estimated quantity movements (compared with FY12) for each connection category and overall.

FY13 budget vs FY12 budget quantities

Connection Category	Change
Streetlighting	1.10%
General	(6.70%)
Irrigation	(3.90%)
Major customers	(20.50%)
Total (excl Fonterra)	**(8.20%)**

Looking forward

From the earlier analysis, it appears that the economic impact of the earthquakes on electricity demand has bottomed out, and there is some indication of demand increasing again. Modest recovery is already evident via rebuild (or reoccupation) of largish commercial connections (for example Briscoes in Salisbury Street, Supervalue Edgeware, Christchurch Press, re-opening of the Ibis Hotel) and there are quite a number of smaller new commercial developments located within the city. However, as discussed above the future impact of the rebuild will be driven primarily by:

- in the CDB, the CERA "blueprint" and its anchor projects, particularly the stadium, convention centre, sports centre, library and performing arts precinct
- in other areas major repairs and rebuilds in the eastern suburbs, and new developments in the north and west, which will show up as trends in the number of energised connections
- population / household growth, as noted the UDS report suggests a range of possible scenarios.

Neither the population/dwelling estimates nor the GDP estimates and forecasts predict the magnitude of observed decline in demand for Orion's delivery service when fitted using historical relationships.[21] It is therefore not appropriate to use them in a simplistic fashion to project several years into the future. At best they can be used to project movement from "where we are at", but that still assumes the same (pre-earthquake) relationships, with the earthquakes simply being a one-off reset. Unfortunately, the forecasts that we do have for the two key drivers are not well aligned, with GDP showing strong "rebound" growth over the next few years, while population grows very slowly by comparison.

The following table shows our assessment of whether a connection category was (materially) earthquake affected, and, if so, comments on the effect and likely drivers of recovery.

Earthquake impact by demand group

Demand group	Material earthquake impact?	Earthquake impact	Recovery
Streetlighting	No	None	NA
General	Yes	Affect via property damage and access restriction, mainly in East and CBD	Overall recovery likely to be in line with population growth, for which there are a number of scenarios available from the UDS. On three out of four scenarios, end point (in any particular year) is below where we would have been had there not been any earthquakes

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[21] Volumes fell about 10% in the first full year after the February earthquake, while population and Canterbury GDP each fell about 2-3%. Based on historical (pre-earthquake) relationships, volumes would have been expected to fall by only around 2.5%.

Irrigation	No	None	NA
Major	Yes	Affect via property damage and access restriction, mainly in the CBD	The recently published CERA CBD plan suggests a significant reduction in the size of the CBD (by land area), and less electrical density in many rebuilds (for example via height restrictions). However, there is expected to be replacement of some key destroyed facilities with quite similar ones, electrically speaking (for example the Stadium, Convention Centre, Performing Arts Centre and Sports Centre)
Large customer connections	No	None	NA
Export and generation credits	Yes	Affect in line with majors	Recovery in line with majors (assessed capacity). Not material

Since population is the primary driver for Orion’s general connection numbers and volumes, it seems reasonable to use the available post-earthquake population forecasts to project general connection chargeable quantities for the CPP. As stated above we have used the UDS Quick recovery scenario for this purpose.

We consider that the economic rebound underpinning the GDP forecasts is construction led, and will not drive growth in electricity demand at that rate. Moreover for the largest connections, other historical factors will be more significant, in particular the CBD rebuild. We have therefore derived our forecasts for the remaining consumer groups using a range of assumptions specific to each consumer group. These can be summarised as follows:

- irrigation – recent two year trend extrapolated across the CPP period
- major consumers – case by case assessment of earthquake impacts and likely rebuild or relocation activity
- streetlighting – extrapolation of five year historical trend
- large capacity – known development plans for each consumer
- export and generation – aligned with major consumer category forecast.

Consistency with demand forecasts included in CPP proposal

The quantity forecasts derived for the price path are specified on the basis of the quantities used to determine revenue. As described above, these quantities are specified on the basis of the consumer groups and charge types used for pricing purposes. They therefore reflect a range of chargeable quantities which are measured at different points throughout the year and at different locations on the network.

Our CPP proposal also includes demand forecasts for the purpose of planning network expenditure. The demand forecasts required for this purpose are not chargeable quantities, nor are they quantities for consumer groups. Rather our planning forecasts are based on maximum system demand, which determines the capacity we require in our network. As our urban network peaks in the winter and our rural network peaks in the summer our demand forecasts consider urban and rural drivers. A detailed description of our demand forecasts for network planning purposes are set out in Section 9.8.

Our underlying trend data is consistent between the planning forecasts and the chargeable quantity forecasts. For example both forecasts use the UDS quick recovery scenario to predict population growth. This is the key driver for our general demand group forecast, and a key input to our maximum demand forecasts, particularly for the urban network. Similarly, the likely developments of our two large consumers (Fonterra and Synlait) are factored into both forecasts. Our irrigation assumptions, which drive peak demand on our rural network, and the chargeable quantities for irrigation consumers are also aligned. They both reflect the anticipated drop off in irrigation growth described above, and in Section 9.8.4.

Summary of forecast quantities

The table below presents the forecast quantities, for each demand group and charge type, from FY13 to FY19.

Forecast quantities

Demand group and charge type	Units	FY13	FY14	FY15	FY16	FY17	FY18	FY19
General connections								
Peak charge	kW	475,925	479,733	483,571	487,439	491,339	495,269	499,232
Volume charge: working weekdays	MWh	1,000,022	1,008,022	1,016,086	1,024,215	1,032,408	1,040,668	1,048,993
Volume charge: nights, weekends, holidays	MWh	1,158,986	1,168,257	1,177,603	1,187,024	1,196,520	1,206,093	1,215,741
Low power factor charge	kVAr	-	-	-	-	-	-	-
Major customer connections								
Fixed charge: standard connections	connections	357	363	368	373	381	384	384
Fixed charge: secondary connections	connections	14	14	14	14	14	14	14
Fixed charge: dedicated equipment	by item $000	1,628,574	1,644,974	1,660,776	1,669,496	1,682,451	1,714,310	1,714,310
Peak charge	kVA	89,667	90,759	91,554	91,912	92,742	93,734	93,734
Capacity charge	kVA	197,105	199,090	201,002	202,058	203,626	207,482	207,482
Irrigation connections								
Capacity charge	kW	70,446	71,383	72,332	73,294	74,269	75,257	76,257
Volume charge: working weekdays	MWh	59,723	60,517	61,322	62,138	62,964	63,801	64,650
Volume charge: nights, weekends, holidays	MWh	103,188	104,560	105,951	107,360	108,788	110,234	111,700
Rebate: power factor correction	kVAr	28,555	28,935	29,320	29,709	30,105	30,505	30,911
Rebate: interruptibility	kW	42,067	42,626	43,193	43,768	44,350	44,940	45,537
Street lighting connections								
Fixed charge	connections	43,248	43,679	44,115	44,555	44,999	45,448	45,901
Peak charge	kW	2,352	2,337	2,322	2,307	2,293	2,279	2,264
Volume charge: working weekdays	MWh	3,252	3,232	3,211	3,191	3,171	3,151	3,131
Volume charge: nights, weekends, holidays	MWh	22,504	22,362	22,222	22,082	21,943	21,805	21,668
Fonterra								
Administration charge	kVA	4,500	9,000	9,000	9,000	9,000	9,000	9,000
Use of distribution assets	kVA	4,500	9,000	9,000	9,000	9,000	9,000	9,000
Synlait								
Administration charge	kVA	5,800	5,800	5,800	5,800	5,800	5,800	5,800
Asset charge	kVA	5,800	5,800	5,800	5,800	5,800	5,800	5,800
Export and generation								
Real power distribution component	kW	2,377	2,401	2,424	2,436	2,455	2,502	2,502
Reactive power distribution component	kVAr	1,419	1,433	1,447	1,454	1,466	1,493	1,493
Generation credits	kWh	256,000	258,578	261,062	262,433	264,469	269,477	269,477

Forecast weighted average growth in quantities

IM 5.4.8(5)(f), (g) and (h)

Values for weighted average quantities are derived, for each charge, in each year from FY13 to FY19, by taking a weighted average of the individual quantity values for each charge shown in the table above.

These weightings are based on the proportions of total distribution revenue collected by each charge in FY13, and are the same for each year from FY13 to FY19, as outlined above.

The relative proportions of fixed and variable components are therefore implicit in how we have defined demand groups, because they encompass each charge type within each consumer category. These charge types include consumption (kWh), demand (kW), capacity (kVA), fixed (connection) and a range of other charges. We have used FY13 budgeted revenue as the basis for determining the weights for each charge for the purpose of deriving the weighted average growth forecast. We summarise the demand group contributions to revenue in the table below.

Derivation of fixed and variable weightings

Budgeted distribution revenue FY13	Unit	Revenue ($000)	Proportion of total (weighting)
General connections			
Peak charge	kW	50,101	37.76%
Volume charge: working weekdays	MWh	48,861	36.82%
Volume charge: nights, weekends, holiday	MWh	6,711	5.06%
Low power factor charge	kVAr	-	0.00%
Major customer connections			
Fixed charge: standard connections	connections	198	0.15%
Fixed charge: secondary connections	connections	4	0.00%
Fixed charge: dedicated equipment	by item ($000)	1,646	1.24%
Peak charge	kVA	9,073	6.84%
Capacity charge	kVA	4,795	3.61%
Irrigation connections			
Capacity charge	kW	5,607	4.23%
Volume charge: working weekdays	MWh	2,918	2.20%
Volume charge: nights, weekends, holiday	MWh	597	0.45%
Rebate: power factor correction	kVAr	(789)	(0.59%)
Rebate: interruptibility	kW	(293)	(0.22%)
Street lighting connections			
Fixed charge	Connections	1,748	1.32%
Peak charge	kW	263	0.20%
Volume charge: working weekdays	MWh	159	0.12%
Volume charge: nights, weekends, holiday	MWh	130	0.10%
Large capacity - Fonterra			
Administration charge	kVA	199	0.15%
Use of distribution assets	kVA	580	0.44%
Large capacity - Synlait			
Administration charge	kVA	148	0.11%
Asset charge	kVA	263	0.20%
Export and generation			
Real power distribution component	kW	(123)	(0.09%)
Reactive power distribution component	kVAr	(24)	(0.02%)
Generation credits	kWh	(77)	(0.06%)
Total		**132,700**	**100%**

Appendix 13 includes reconciliation between the relative proportions of fixed and variable charges outlined above and the information contained in our FY12 DPP compliance statement. This demonstrates compliance with clause 5.4.8(5)(g). Our FY12 DPP compliance statement is our most recent statement of compliance against the DPP price path. In it we disclose audited quantities for each price for FY10. This is because the price path uses lagged quantities.

The prices are specified as fixed and variable prices using the same units (ie: MWh, kW, connections etc) we have used in our weighted average growth in quantities model for the CPP. That is our CPP model has been prepared using the same units which correspond to our prices. The CPP model also includes FY11 and FY12 actual quantities and forecasts thereafter.

We also note:

- for the purpose of the reconciliation we have ignored all transmission charge quantities, as these fall outside the CPP price path
- our DPP quantities exclude dedicated equipment charges (and hence quantities) for major consumers. These fall outside the DPP price path as the services are deemed contestable. However, we have included them in the CPP quantities, as the assets are included in our RAB, and other associated costs are included in our

building blocks

- our CPP quantities include specific volumes for Fonterra. These do not appear in our DPP Compliance Statement because the services were not provided in FY10 and hence no quantities were recorded at that time.

Summary

The amounts for forecast weighted average growth in quantities, for FY14 to FY19 are the annual percentage changes in weighted average quantities.

We note that the weighted average quantities are not specified in any particular unit – they are a combination of quantities specified in different units. It is therefore best considered a “notional” quantity rather than an average quantity of particular item. Because we are determining growth rates, rather than absolute quantities, the use of these notional quantities is appropriate.

Forecast weighted average growth in quantities

	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Weighted average quantities	644,951	650,243	655,518	660,685	665,995	671,673	676,792
Weighted average growth in quantities		0.82%	0.81%	0.79%	0.80%	0.85%	0.76%

7.3 Building block allowable revenues

IM 5.4.7 and 5.3.2

This section describes how the amounts for BBAR are determined.

7.3.1 Building blocks allowable revenue (before and after tax)

BBAR represents the annual allowable revenue which is made up of a number of building blocks, used to determine the CPP price path. It is the primary input into the determination of MAR, as described in Section 7.2.

The determination of BBAR is addressed in clauses 5.4.7 and 5.3.2 of the CPP IM. Clause 5.3.2 was amended in November 2012. Our draft CPP proposal (which formed the basis of our consumer consultation, initial audit and verification processes) was prepared using the consultation draft for the amended clause, published in August 2012. Our final proposal has been amended to comply with the new Determination.[22]

The effect of the amendment is to incorporate revised cash flow timing assumptions into the derivation of BBAR.

IM requirements

Clause 5.4.7(1) of the IMs requires that a CPP proposal must contain amounts for:

- BBAR before tax
- BBAR after tax

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[22] Commerce Commission, Electricity and Gas Input Methodology Determination Amendments (no. 2) 2012, Decision [2012] NZCC 34, 15 November 2012

for each disclosure year of the next period.

Clause 5.4.7(2) of the IMs requires that a CPP proposal must contain all data, information, calculations and assumptions used to determine the amounts for BBAR before and after tax.

In this sub-section we present amounts for BBAR before and after tax, for the next period (comprising the assessment period and the CPP regulatory period: FY13-FY19), and describe how they are determined from their primary inputs.

We also present amounts for BBAR for the two years prior to the start of the next period (FY11 and FY12). We use these amounts to determine the value of claw-back, as described in Section 7.2.2.

Summary of amounts for building blocks allowable revenue

Clause 5.3.3(1) of the CPP IM defines BBAR after tax as BBAR before tax less the forecast regulatory tax allowance.

The table below shows amounts for BBAR before and after tax, and regulatory tax allowance, for FY11 to FY19.

Building blocks allowable revenue ($000 nominal)	Current Period		Assessment Period		CPP Period				
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
BBAR before tax	142,926	130,926	155,189	186,732	151,819	164,599	169,450	176,095	185,020
Regulatory tax allowance	16,048	10,836	16,488	21,781	14,234	15,742	16,437	17,183	17,852
BBAR after tax	126,878	120,090	138,701	164,951	137,585	148,857	153,012	158,912	167,168

BBAR before tax increases in the years leading up to the CPP period, with the exception of FY12. In FY12 significant insurance proceeds have been received which are offset against BBAR. There is a step down in BBAR in FY15, primarily due to the lower cost of capital permitted from FY15 onwards which is used for the return on capital element. From FY15 to FY19, BBAR shows a small upward year on year trend.

We describe how the amounts for the inputs to BBAR after tax are determined in the following section. In addition we describe the determination of the forecast regulatory tax allowance in Section 7.6.1.

Determining building blocks allowable revenue before tax

Formula for building blocks allowable revenue before tax

BBAR before tax is the result of the following formula:

(regulatory investment value x *cost of capital + total value of commissioned assets* x *(*TF_{VCA} *- 1) + term credit spread differential allowance* x *TF – total revaluation) / (*TF_{rev} *– corporate tax rate* x *TF)*

+ (total depreciation x *(1 – corporate tax rate* x *TF)*

+ forecast operating expenditure x *TF* x *(1 – corporate tax rate)*

- other regulated income x *TF* x *(1 – corporate tax rate)*

+ (closing deferred tax – opening deferred tax) x *(TF – 1)*

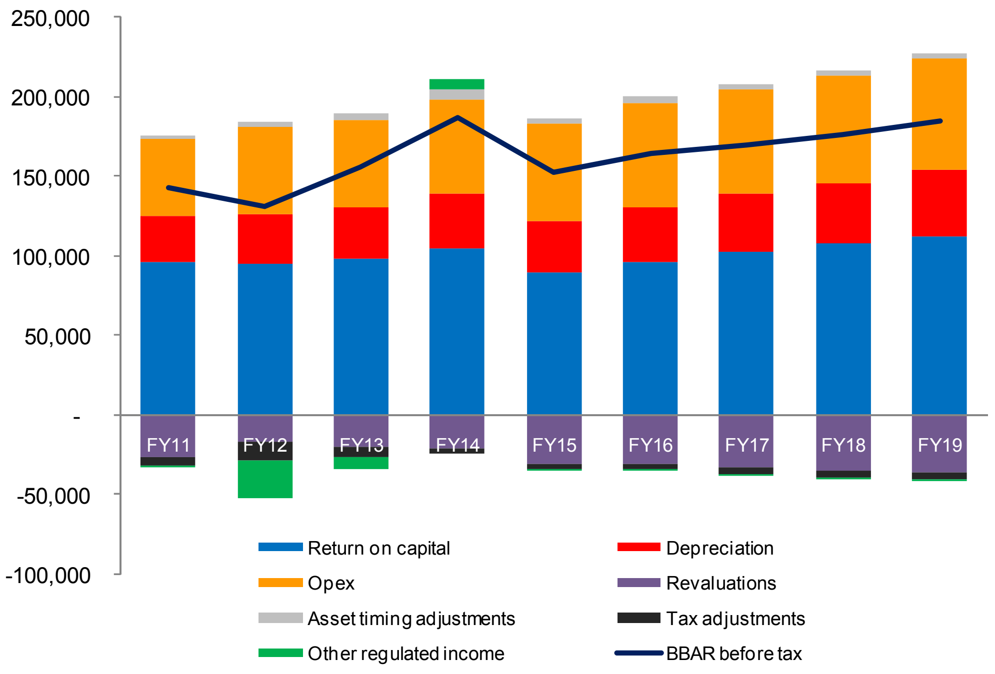
+ (permanent differences + regulatory tax adjustments – utilised tax losses) x corporate tax rate x *TF) / (*TF_{rev} *– corporate tax rate* x *TF)*

This is based on the formula for BBAR before tax specified in clause 5.3.2(1) of the IM. We note that the formula in the amended IM contains an error by including an uneven number of brackets. We have ignored the final bracket in the published formula, which we believe is superfluous to the determination of BBAR.

Derivation of building blocks allowable revenue before tax

The chart below illustrates the core components of BBAR before tax. As illustrated below the return on capital is the largest component, followed by opex, depreciation and revaluations (which are treated as revenue). BBAR is increasing over time, although there is a step-change in the return on capital component in FY15 as a result of a reduction in the cost of capital permitted in the CPP regulatory period. The impact of the notable insurance proceeds received in FY12 is evident, and is included in other regulated income. In FY14 we have a loss on sale for our Armagh St site. This appears as negative other regulated income.

Building blocks allowable revenue before tax, by component ($000 nominal)



The table below sets out the derivation of BBAR before tax. It shows the amounts for BBAR before tax, and those of each of the inputs included in the formula stated above.

Building blocks allowable revenue ($000 nominal)	Current Period		Assessment Period	
	FY11	FY12	FY13	FY14
Regulatory investment value	788,701	805,728	828,020	882,377
Cost of capital	8.77%	8.77%	8.77%	8.77%
Total value of commissioned assets	32,951	47,349	77,100	106,398
Term credit spread differential allowance	-	-	-	-
Total revaluation	19,213	12,827	15,207	15,678
Total depreciation	30,817	32,348	33,480	35,886
Operating expenditure	47,609	54,319	54,640	58,753
Other regulated income	483	23,453	7,357	(6,945)
Opening deferred tax	(6,210)	(10,529)	(16,065)	(20,535)
Closing deferred tax	(10,529)	(16,065)	(20,535)	(25,571)
Permanent differences	(55)	(17,273)	(2,926)	6,815
Regulatory tax adjustments	(11,435)	(11,739)	(12,613)	(14,175)
Utilised tax losses	-	-	-	-
TF	1.043	1.043	1.043	1.043
TFVCA	1.043	1.043	1.044	1.043
TFREV	1.035	1.035	1.035	1.035
Corporate tax rate	30%	28%	28%	28%
BBAR before tax	142,926	130,926	155,189	186,732
Regulatory tax allowance	16,048	10,836	16,488	21,781
BBAR after tax	126,878	120,090	138,701	164,951

	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Regulatory investment value	947,866	1,020,126	1,096,137	1,144,264	1,198,366
Cost of capital	6.92%	6.92%	6.92%	6.92%	6.92%
Total value of commissioned assets	92,013	98,674	69,918	76,791	59,604
Term credit spread differential allowance	-	-	-	-	-
Total revaluation	22,543	22,755	24,618	25,847	27,123
Total depreciation	33,535	35,719	37,641	39,756	42,826
Operating expenditure	61,205	65,242	64,884	66,419	69,852
Other regulated income	823	840	859	877	896
Opening deferred tax	(25,571)	(34,332)	(44,032)	(52,799)	(61,578)
Closing deferred tax	(34,332)	(44,032)	(52,799)	(61,578)	(70,490)
Permanent differences	46	47	48	49	50
Regulatory tax adjustments	(7,111)	(8,305)	(9,125)	(9,477)	(9,531)
Utilised tax losses	-	-	-	-	-
TF	1.034	1.034	1.034	1.034	1.034
TFVCA	1.028	1.031	1.033	1.034	1.034
TFREV	1.028	1.028	1.028	1.028	1.028
Corporate tax rate	28%	28%	28%	28%	28%
BBAR before tax	151,819	164,599	169,450	176,095	185,020
Regulatory tax allowance	14,234	15,742	16,437	17,183	17,852
BBAR after tax	137,585	148,857	153,012	158,912	167,168

We describe how the amounts for the inputs to BBAR before tax are determined in the following sections:

- regulatory investment value (Section 7.3.2)
- total value of commissioned assets (Section 7.3.3)
- total depreciation (Section 7.3.4)
- total revaluation (Section 7.3.5)
- TF, TF_{VCA} and TF_{rev} (Section 7.3.6)
- other regulated income (Section 7.3.7)
- forecast operating expenditure (Section 7.3.8)
- term credit spread differential allowance (Section 7.3.9)
- regulatory tax adjustments, utilised tax losses and permanent differences (respectively, Sections 7.6.1, 7.6.2 and 7.6.3)
- closing deferred tax and opening deferred tax (Section 7.6.6)
- cost of capital (Section 7.7.1).

Information in spreadsheet format

Clause 5.4.7(4) of the CPP IMs requires a CPP proposal to present the values for BBAR before and after tax, as well as all data, information, calculations, values, amounts and assumptions used to determine these amounts, in a spreadsheet format which clearly demonstrates how the amounts for BBAR before and after tax have been derived. These spreadsheets accompany this proposal. A list of spreadsheets which support the price path is included at the end of this section of the proposal.

7.3.2 Regulatory investment value

Regulatory investment value determines the value of assets to be used for the purposes of calculating the return on capital element of the building blocks.

IM requirements

Clause 5.4.7(2)(a)(i) of the CPP IM requires that a CPP proposal must contain forecasts of regulatory investment value, as used to determine the amounts for BBAR.

As discussed in Section 7.3.1, we also provide the amounts for the regulatory investment value from FY11, which we use to determine the value of claw-back.

Regulatory investment value

Clause 5.3.2(2) of the CPP IM defines regulatory investment value as total opening RAB value plus opening deferred tax.

The table below shows regulatory investment value, total opening RAB and opening deferred tax, from FY11 to FY19.

Regulatory Investment Value ($000 nominal)	Current Period		Assessment Period		CPP Period				
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Total opening RAB value	794,911	816,257	844,085	902,912	973,437	1,054,458	1,140,168	1,197,063	1,259,945
Opening deferred tax	(6,210)	(10,529)	(16,065)	(20,535)	(25,571)	(34,332)	(44,032)	(52,799)	(61,578)
Regulatory investment value	**788,701**	**805,728**	**828,020**	**882,377**	**947,866**	**1,020,126**	**1,096,137**	**1,144,264**	**1,198,366**

Regulatory investment value increases from $789m in FY11 to $1,198m in FY19. This reflects underlying growth in RAB, which is partly offset by an increasing deferred tax liability over the same period.

To illustrate how the RAB values are determined, we show in the table below a full roll-forward of the RAB from FY10 to FY19. As the Initial RAB is determined as at 1 April 2009, which is the starting point for the RAB under the IMs, we show the roll forward from that date.

Total closing RAB value is equal to total opening RAB value, less total depreciation, plus total revaluation, plus the value of commissioned assets, less the sum of opening RAB values of disposed assets. We set out the Initial RAB, the RAB roll-forward, and its components, in more detail in Section 7.5.

RAB roll-forward ($000 nominal)	Current Period			Assessment Period		CPP Period				
	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Total opening RAB value	774,919	794,911	816,257	844,085	902,912	973,437	1,054,458	1,140,168	1,197,063	1,259,945
less Total depreciation	29,014	30,817	32,348	33,480	35,886	33,535	35,719	37,641	39,756	42,826
plus Total revaluation	15,854	19,213	12,827	15,207	15,678	22,543	22,755	24,618	25,847	27,123
plus Sum of the value of commissioned assets	33,152	32,951	47,349	77,100	106,398	92,013	98,674	69,918	76,791	59,604
less Sum of the value of disposed assets	-	-	-	-	15,665	-	-	-	-	-
Total closing RAB value	794,911	816,257	844,085	902,912	973,437	1,054,458	1,140,168	1,197,063	1,259,945	1,303,846

We describe how the amounts for deferred tax are determined in Section 7.6.6.

7.3.3 Commissioned assets

Commissioned assets are new assets added to the RAB. The value of commissioned assets in a given year affects BBAR in the following ways:

- the value of commissioned assets is a direct input in the formula for BBAR as stated in Section 7.3.1
- the value of commissioned assets is added to the RAB, which affects the regulatory investment value (and hence the return on capital component of BBAR)
- it affects the depreciation and revaluation components of BBAR (as discussed in Sections 7.3.4 and 7.3.5)
- the value of commissioned assets affects some of the tax adjustments to BBAR, which are discussed in Section 7.6.

IM requirements

Clause 5.4.7(2)(a)(ii) of the CPP IM requires that a CPP proposal contains forecasts of the total value of commissioned assets, as used to determine the amounts for BBAR.

As discussed in Section 7.3.1, we also provide historical amounts for total value of commissioned assets, which we use to determine the value of claw-back.

Total value of commissioned assets

The table below shows the total value of commissioned assets from FY11 to FY19.

Commissioned assets ($000 nominal)	Current Period		Assessment Period		CPP Period				
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Total value of commissioned assets	32,951	47,349	77,100	106,398	92,013	98,674	69,918	76,791	59,604

The total value of commissioned assets is higher in FY14, FY15 and FY16 than in previous or subsequent years, with a step up again in FY18. The forecast includes assets we plan to construct, as well as assets we plan to acquire, notably spur assets from Transpower. Our capex plan is discussed in detail in Sections 8 and 9 of this proposal.

We describe how the amounts for the total value of commissioned assets are determined in Section 7.5.5.

7.3.4 Depreciation

All assets in the RAB, other than land and easements, are depreciated over their remaining lives. This allows the costs of the assets to be recovered over a number of years, reflecting their service provision.

Total depreciation is a direct input in the formula for BBAR. It represents the depreciation, or return of capital, element of the building blocks.

IM requirements

Clause 5.4.7(2)(a)(iii) of the CPP IM requires that a CPP proposal must contain forecasts of total depreciation, as used to determine the amounts for BBAR.

As discussed in Section 7.3.1, we also provide historical amounts for total depreciation, which we use to determine the value of claw-back.

Total depreciation

The table below shows total depreciation from FY11 to FY19.

Total depreciation ($000 nominal)	Current Period		Assessment Period		CPP Period				
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Total depreciation	30,817	32,348	33,480	35,886	33,535	35,719	37,641	39,756	42,826

Total depreciation increases over the period shown, from $31m in FY11 to $43m in FY19. This is consistent with an increasing RAB value over the same period. The step down in FY15 reflects our proposed alternative depreciation method during the CPP regulatory period.

We explain how the amounts for total depreciation are determined in Section 7.5.3.

7.3.5 Revaluation

The RAB is presented in nominal terms (along with the rest of the inputs to BBAR and the price path). To ensure it retains its real value over time, the RAB is revalued each year in accordance with changes to the inflation rate.

Total revaluation is a direct input in the formula for BBAR. Revaluations reduce allowable revenue – they offset (in present value terms) the additional return on capital and depreciation that result, over time, from revaluations.

IM requirements

Clause 5.4.7(2)(a)(iv) of the CPP IM requires that a CPP proposal must contain forecasts of total revaluation, as used to determine the amounts for BBAR.

As discussed in Section 7.3.1, we also provide historical amounts for total revaluation, which we use to determine the value of claw-back.

Total revaluation

The table below shows total revaluation from FY11 to FY19 and the revaluation rate used in its derivation.

Total revaluation ($000 nominal)	Current Period		Assessment Period		CPP Period				
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Revaluation rate	2.42%	1.57%	1.80%	1.77%	2.32%	2.17%	2.17%	2.17%	2.17%
Total revaluation	19,213	12,827	15,207	15,678	22,543	22,755	24,618	25,847	27,123

Total revaluation increases over the period shown, from $19m to $27m, although it reduces in FY12, and is also lower than FY11 in FY13 and FY14. Total revaluation is a product of the revaluation rate and the opening RAB. As shown in the above table the revaluation rate fluctuates in the historical period. As stated above the RAB value increases over the period.

We explain how the values for total revaluation are determined in Section 7.5.4.

7.3.6 Timing factors

The definition of BBAR before tax (in clause 5.3.2) of the CPP IM incorporates cash flow timing assumptions.

The BBAR formula includes four timing factor adjustment terms, two relating to commissioned assets (TF_{VCA} and PV_{VCA}), one to revenue (TF_{rev}), and one to the remaining components of BBAR (TF). These terms adjust the value of different elements of the building blocks, so that building block allowable revenue is equal to building blocks costs, after adjustment for timing differences in the relevant cost components.

IM requirements

Clause 5.4.7(2)(b) of the CPP IM requires that a CPP proposal must contain all data, information, calculations and assumptions used to derive the forecasts of TF_{VCA}, PV_{VCA}, TF_{rev} and TF, as used to determine the amounts for BBAR.

TF_{VCA} and PV_{VCA}

TF_{VCA} is the timing factor adjustment term for commissioned assets. It is the amount that the value of commissioned assets is to be multiplied by to derive the value of commissioned assets in year-end terms. Its value depends on the commissioning dates of the new assets added to the RAB each year.

Clause 5.3.2(4)(c) of the CPP IM defines TF_{VCA} as PV_{VCA} x (1 + cost of capital) / total value of commissioned assets.

PV_{VCA} is the total value of commissioned assets in “year-start” terms. Clause 5.3.2(4)(d) of the CPP IM defines PV_{VCA} as the sum of the present value of closing RAB values for commissioned assets (ie the total value of commissioned assets), calculated by discounting the closing RAB value using the cost of capital from the commissioning date to the start of the relevant disclosure year.

The table below shows TF_{VCA}, and PV_{VCA}, the cost of capital, and total value of commissioned assets, from FY11 to FY19.

Timing factor for commissioned assets ($000 nominal)	Current Period		Assessment Period		CPP Period				
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
PV_{VCA}	31,594	45,400	73,982	102,054	88,451	95,128	67,579	74,264	57,643
Cost of capital	8.77%	8.77%	8.77%	8.77%	6.92%	6.92%	6.92%	6.92%	6.92%
Total value of commissioned assets	32,951	47,349	77,100	106,398	92,013	98,674	69,918	76,791	59,604
TF_{VCA}	1.043	1.043	1.044	1.043	1.028	1.031	1.033	1.034	1.034

The table below shows PV_{VCA}, and the total value of commissioned assets and the cost of capital, from FY11 to FY19.

Present value of commissioned assets ($000 nominal)	Current Period		Assessment Period		CPP Period				
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Total value of commissioned assets	32,951	47,349	77,100	106,398	92,013	98,674	69,918	76,791	59,604
Cost of capital	8.77%	8.77%	8.77%	8.77%	6.92%	6.92%	6.92%	6.92%	6.92%
PV_{VCA}	31,594	45,400	73,982	102,054	88,451	95,128	67,579	74,264	57,643

In order to derive the values identified above it is necessary to determine the timing of commissioned assets, year by year, and within each year. We discuss our approach to this in Section 7.5.5. In summary, we assume that all non-acquired assets are commissioned evenly across the year of commissioning, ie on average in the middle of the year. Most projects are also expected to be commissioned in the year in which the capex is incurred. We have identified some exceptions, larger projects, where capex runs over more than one year. In these instances assets are commissioned in the final year of expenditure. These assumptions are appropriately reflected in our commissioned date assumptions.

For the assets we will acquire from Transpower, we have planned transfer dates for each group of assets.

We presented the total value of commissioned assets in Section 7.3.3. In Section 7.5.5, we describe how these amounts are determined, and we also state the forecast commissioning dates for each group of assets and describe how these are used to derive PV_{VCA} and TF_{VCA}.

We describe how the amounts for the cost of capital are determined in Section 7.7.1.

TF_{rev}

TF_{rev} is the timing factor adjustment term for revenue. It is the amount that revenue is to be multiplied by to derive the value of revenue in year-end terms. Its value is fixed, and clause 5.3.2(4)(b) of the CPP IM defines TF_{rev} as (1 + cost of capital)$^{148/365}$.

The table below shows TF_{rev} and the cost of capital from FY11 to FY19.

Timing factor for revenue ($000 nominal)	Current Period		Assessment Period		CPP Period				
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Cost of capital	8.77%	8.77%	8.77%	8.77%	6.92%	6.92%	6.92%	6.92%	6.92%
TF_{REV}	1.035	1.035	1.035	1.035	1.028	1.028	1.028	1.028	1.028

TF_{rev} equals 1.035 from FY11 until FY14, and 1.028 thereafter. The change in value at FY15 is due to the different cost of capital used in the CPP regulatory period. The TF_{rev} values are lower than those for TF (refer below), reflecting the assumption that on average revenue is collected after the midpoint of the year.

TF

TF is the timing factor adjustment term for all elements of the building blocks other than commissioned assets and revenue. It applies to operating expenditure, other regulated income, term credit spread differential allowance and the regulatory tax allowance.

It is the amount that the values for these items are to be multiplied by to derive the values in year-end terms. Its value is fixed, based on an assumption that each of these items occurs uniformly over the year.

Clause 5.3.2(4)(a) of the CPP IM defines TF as (1 + cost of capital)$^{182/365}$.

The table below shows TF and the cost of capital from FY11 to FY19.

Timing factor for general building block items ($000 nominal)	Current Period		Assessment Period	
	FY11	FY12	FY13	FY14
Cost of capital	8.77%	8.77%	8.77%	8.77%
TF	1.043	1.043	1.043	1.043

	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Cost of capital	6.92%	6.92%	6.92%	6.92%	6.92%
TF	1.034	1.034	1.034	1.034	1.034

TF equals 1.043 from FY11 until FY14, and is 1.034 thereafter. The change in value at FY15 is due to the different cost of capital used in the CPP regulatory period.

7.3.7 Other regulated income

Clause 5.3.2(7) of the CPP IM defines other regulated income as income associated with the supply of electricity distribution services other than through prices, investment related income, capital contributions or vested assets.

Other regulated income is a direct input in the formula for BBAR. Any other regulated income directly reduces BBAR (before timing factor adjustments). This is because the more revenue that an EDB gets from other sources, the less it has to collect from consumers in order to recover building block costs.

IM requirements

Clause 5.4.7(2)(a)(v) of the CPP IM requires that a CPP proposal must contain forecasts of other regulated income, as used to determine the amounts for BBAR. As discussed in Section 7.3.1, we also provide historical amounts for other regulated income, which are used to determine the value of claw-back.

Clause 5.4.7(2)(c) of the CPP IM requires that a CPP proposal must contain all data, information, calculations and assumptions used to derive the forecasts of other regulated income.

Clause 5.4.7(3) of the CPP IM requires that a CPP proposal must contain actual other regulated income for each disclosure year of the current period, and data, calculations and assumptions demonstrating how the forecasts of other regulated income are consistent with the actual amounts for the current period.

Summary of other regulated income

The table below shows other regulated income for FY08 to FY19.

Other regulated income ($000 nominal)	Current Period					Assessment Period		CPP Period				
	FY08	FY09	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Other regulated income	1,085	3,350	725	483	23,453	7,357	(6,945)	823	840	859	877	896

Other regulated income is between $0.8m and $0.9m over the CPP regulatory period. This follows atypically high values in FY12 and FY13, which are primarily due to insurance proceeds. The negative value in FY14 includes the expected loss on sale of our central city head office site which is to be acquired by CERA.

Other regulated income is around 0.5% of BBAR before tax, during the CPP regulatory period.

Breakdown of historical and forecast amounts for other regulated income

Historical items

Historical other regulated income since FY08 comprises three items:

- insurance proceeds
- gains on sales
- sundry network revenue (primarily from rental agreements).

The table at the end of this sub-section shows the historical values for these items from FY08 to FY12. Gains on sales are the most significant item in FY08 and FY09. These reflect sales of vehicles and other non-system assets which have reached the end of their useful lives (and are assumed to be fully depreciated). We received $22.4m of insurance proceeds in FY12. We are expecting an additional $6.6m in FY13, but no more thereafter.

FY08-FY12 values reflect historical actual values. FY13 values reflect our budgeted values. Forecasts are derived for FY14 – FY19.

Forecast method

It is difficult to forecast gains on sale and hence which assets may be sold and their future sales price. Accordingly we have considered historical data in order to determine our forecast. We note the variability in our recent five year history. In the last five years, values have been as low as $41,000 per annum and as high as $2.4m per annum. We consider that $300,000 is a reasonable estimate of a long-term average, and we use this as our forecast for all years from FY14. These gains are expected to be predominantly related to the sale of non network assets such as vehicles which have reached the end of their useful lives.

Orion has various rental agreements in place for shared use of our network assets. This small amount of rental income makes up sundry network revenue. The agreements mainly comprise attachments (for equipment) to Orion's overhead poles by other companies. We do not actively seek out these agreements, but are approached by other organisations seeking to install their assets on our network.

The table below shows the network rental agreements that we currently have in place.

Network rental agreements	
Other party	**Assets involved**
Trustpower	Pole attachment - Coleridge
RDU 98.5 FM	Pole attachment - Nicholson Park
Radio Network	Pole attachment- Nicholson Park
TelstraClear	Pole attachment - Christchurch City
Tait Electronics	Wireless IP SCADA network supply
ARC Innovations	Various poles, on which ARC has equipment to manage its smart meter relay system

These rental agreements are long term agreements which are managed by Orion and agreed rental costs (revenue to Orion) are generally recovered on an annual basis.

We have forecast amounts for sundry network revenue, shown below, based on known contracts in place at this time. Our forecast takes into account the cessation of an agreement with Transpower for the shared use of a fibre optic cable that was destroyed by the earthquakes.

There are no contingencies built into these forecasts. For each of the items, we convert real forecasts for FY14 to FY19 to nominal values using CPI.

Historical and forecast amounts

The table below shows other regulated income, both historical and forecast values, in its component parts, from FY08 to FY19. As demonstrated below, the forecasts for other income are not significant during the CPP regulatory period.

We believe that our forecasts are consistent with the historical values. The time series is not smooth though, since other regulated income often includes atypical items, and this is particularly the case for us following the earthquakes.

Other regulated income ($000 nominal)	Current Period					Assessment Period		CPP Period				
	FY08	FY09	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Sundry Network revenue	754	950	623	442	564	457	499	510	521	533	544	556
Insurance Proceeds	-	-	-	-	22,353	6,600	-	-	-	-	-	-
Gain (loss) on sale of miscellaneous assets	331	2,400	102	41	536	300	306	312	319	326	333	340
Gain (loss) on sale of Armagh St land	-	-	-	-	-	-	(7,750)	-	-	-	-	-
Other regulated income	**1,085**	**3,350**	**725**	**483**	**23,453**	**7,357**	**(6,945)**	**823**	**840**	**859**	**877**	**896**

7.3.8 Operating expenditure

Operating expenditure is expenditure that is expensed rather than capitalised. Operating expenditure is a direct input in the formula for BBAR.

IM requirements

Clause 5.4.7(2)(d) of the CPP IM requires that a CPP proposal must contain amounts for forecast operating expenditure, as used to determine the amounts for BBAR.

As discussed in Section 7.3.1, we also provide historical amounts for operating expenditure, which are used to determine the value of claw-back.

Operating expenditure included in the BBAR is derived after application of the cost allocation method set out in the IMs. Our approach to this is described in Section 7.4.1. As we describe in that section all of our forecast operating costs are directly attributable to electricity lines services, and thus we have no allocations of opex which fall outside BBAR.

Operating expenditure

The table below shows operating expenditure from FY11 to FY19.

Operating expenditure ($000 nominal)	Current Period		Assessment Period		CPP Period				
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Operating expenditure	47,609	54,319	54,640	58,753	61,205	65,242	64,884	66,419	69,852

Operating expenditure increases over the period shown, although the rate of increase is not even. Expenditure for FY11 and FY12 reflects actual historical opex, which is influenced by the costs of immediately responding to the earthquakes. Opex for FY13 reflects our budgets for the year. The forecast is derived from a bottom up forecast of a large number of opex projects and programmes. Sections 8 and 9 of the proposal describe our opex plan in detail.

7.3.9 Term credit spread differential allowance

The term credit spread differential allowance is an input to the formula for BBAR. It is an allowance which may be included in the return on capital component of BBAR.

The return on capital allowance in BBAR is derived as the value of assets multiplied by the cost of capital. As we discuss in Section 7.7, the Commission determines the cost of capital consistent with the Part 4 of the IMs. This requires an estimate of the cost of debt which is derived from estimates of five-year bonds. A five year period aligns with the five year regulatory period.[23] The term credit spread differential allowance compensates any EDB which has an average debt tenor which exceeds five years.

IM requirements

Clause 5.4.7(2)(e) of the CPP IM requires that a CPP proposal must contain amounts for any proposed term credit spread differential allowance which is used to determine the amounts for BBAR.

Term credit spread differential allowance

We are not proposing any term credit spread differential allowance during this period. As we discuss in Section 7.7.2, this is because we do not have any debt with a tenor of more than five years.

7.4 Cost allocation

IM 5.4.9 – 5.4.10, 5.3.5, 2.1.1 – 2.1.6

7.4.1 Allocation of operating costs

Outcome of applying IM clauses relating to cost allocation method

Clause 5.3.5(1) of the CPP IM states that opex forecast in each year of the next period must be consistent with an allocation of opex to electricity distribution services carried out in respect of the last disclosure year of the current period in accordance with clause 2.1.1 of the IMs.

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[23] Alternative costs of debt are derived for CPPs which are for three or four year terms.

Clause 2.1.1(1) of the IMs states that any opex directly attributable to electricity distribution services supplied by Orion must be allocated to electricity distribution services. Clause 2.1.1(2) states that any opex directly attributable to other regulated services must be allocated to the other regulated services. Clause 2.1.1(3) states that any opex not directly attributable must be allocated to electricity distribution services and other regulated services, in accordance with the allocation methodologies specified.

We do not have any opex which is not directly attributable to electricity distribution services. Orion does not operate any non-regulated services. While Orion owns Connetics, an electrical contracting business, this is operated on a purely arms-length basis, managed by its own management team and systems, and governed by its own board of directors. Thus all of the opex included in our forecasts is directly attributable to electricity distribution services. As there are no components of opex which are 'not directly attributable', we have not been required to apply the allocation methods as prescribed in clause 2.1.1(3) of the IMs.

The CPP IM requires allocations to be made for the purpose of a CPP proposal on the same basis as those made in the last disclosure year of the current period. That year is FY12. As disclosures have not yet been published for FY12 this is not possible. Further FY12 disclosures are to be made in accordance with the 2008 Information Disclosure Requirements (IDRs) which are not specified consistent with the IMs. This is explained further in Section 3.7.

Orion has provided the Commission with cost allocation information, prepared consistent with clause 2.1.1 of the IMs for FY10. This was completed via a s53ZD Notice issued to us by the Commission on 27 August 2012. For FY10 the allocation of opex is consistent with that described above, ie all opex is directly attributable to electricity distribution services. There have been no changes to our circumstances since FY10, which would cause this result to change for FY11 and FY12. Accordingly, the cost allocation for our CPP proposal is consistent with our position for the current period.

7.4.2 Allocation of RAB values

Clause 5.4.9 of the CPP IM includes similar allocation requirements for asset values. That is, where assets are not directly attributable to the provision of electricity distribution services, they must be allocated between these services and other regulated, or unregulated services. Information pertaining to the allocations is to be provided in a CPP proposal.

Consistent with our cost allocations, we have no assets which are not directly attributable to electricity distribution services. This is demonstrated in our response to the Commission's 53ZD Notice for the FY10 year. This situation has not changed in FY11 and FY12. Accordingly our asset allocation for our CPP proposal is consistent with our position for the current period.

We have not provided the information specified in clauses 5.4.9(2) and 5.4.10 of the CPP IMs.

7.4.3 Supporting information

Clause 5.4.9 of the IMs states that where we make allocations of operating costs or asset values not directly attributable, the CPP proposal must contain certain information and Schedules. Clause 5.4.10 requires certain Directors' representations to be made where certain allocation methods have been applied. As we do not make any allocations of not directly attributable costs or asset values, these information and certification requirements do not apply to us, including the requirements to provide the information specified in Schedules B and C of the IMs.

7.5 Asset valuation

7.5.1 RAB roll forward

IM 5.4.11

The RAB represents the regulatory value of Orion's asset base. It is a primary input to the return on capital, depreciation and revaluation elements of the building blocks. Under the building blocks methodology, Orion is permitted to recover the value of its asset base over the life of the assets, including a fair return on those assets. The RAB comprises many individual assets, both network and non network assets. For the purpose of this section our references to RAB refer to the sum of these individual asset values which together combine to derive our total RAB.

Closing RAB value in any year is determined by "rolling forward" the opening RAB value, by adding assets commissioned in the year, increasing it for annual revaluations, and reducing it for annual deprecation and asset disposals made during the year.

IM requirements

Clause 5.4.11 of the CPP IM requires that a CPP proposal must provide values for the:

- total opening RAB value
- sum of the forecast value of commissioned assets
- sum of the closing RAB values

for each disclosure year after the last disclosure year in which a disclosure has been made pursuant to an ID Determination, or for each disclosure year after FY09 where no such disclosure has been made, until the last disclosure year of the next period.

An ID Determination is defined in Part 1 of the IMs as an information disclosure determination in relation to an EDB made by the Commission under section 52P of the Act. The first ID Determination made under section 52P is dated 1 October 2012. Disclosures consistent with this Determination have not yet been published.

Instead, as discussed in Section 3.7, Orion has made a disclosure for the FY10 disclosure year in response to a s53ZD Notice issued by the Commission on 27 August 2012. This information is calculated in accordance with the IMs, including establishing an Initial RAB value in accordance with clause 2.2.1.

In accordance with clause 5.4.11(b) we have included RAB roll forward information for each disclosure period commencing after disclosure year FY09, until the end of the next period.

Accordingly some of the values presented are historical, rather than forecast values. This information is summarised in the RAB roll-forward table overleaf.

RAB roll-forward

Clause 5.3.6(8) of the IMs defines total closing RAB value as the sum of closing RAB values for all assets. Clause 5.3.6(3) of the CPP IM defines the closing RAB value of an individual asset as: opening RAB value less depreciation plus revaluation, for assets with opening RAB values; as the value of commissioned asset, for assets commissioned in the year; and as nil for assets disposed of in the year.

This asset-specific definition of closing RAB value implies that total closing RAB value is equal to total opening RAB value, less total depreciation, plus total revaluation, plus the value of commissioned assets, less the sum of opening RAB values of disposed assets.

Clause 5.3.6(7) defines total opening RAB value as the sum of all initial RAB values in the disclosure year FY10, and as the sum of closing RAB values in the preceding disclosure year for all years after FY10.

The table below shows total opening RAB value, total depreciation, total revaluation, the sum of the value of commissioned assets, the sum of the value of disposed assets, and total closing RAB value, for each disclosure year from FY10 to FY19.

We note that we do not have any lost or found assets during this period.

RAB roll-forward ($000 nominal)	Current Period			Assessment Period	
	FY10	FY11	FY12	FY13	FY14
Total opening RAB value	774,919	794,911	816,257	844,085	902,912
less Total depreciation	29,014	30,817	32,348	33,480	35,886
plus Total revaluation	15,854	19,213	12,827	15,207	15,678
plus Sum of the value of commissioned assets	33,152	32,951	47,349	77,100	106,398
less Sum of the value of disposed assets	-	-	-	-	15,665
Total closing RAB value	794,911	816,257	844,085	902,912	973,437

	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Total opening RAB value	973,437	1,054,458	1,140,168	1,197,063	1,259,945
less Total depreciation	33,535	35,719	37,641	39,756	42,826
plus Total revaluation	22,543	22,755	24,618	25,847	27,123
plus Sum of the value of commissioned assets	92,013	98,674	69,918	76,791	59,604
less Sum of the value of disposed assets	-	-	-	-	-
Total closing RAB value	1,054,458	1,140,168	1,197,063	1,259,945	1,303,846

We describe how the amounts for each item in this table are determined in the following sections:

- total depreciation (Section 7.5.3)
- total revaluation (Section 7.5.4)
- commissioned assets (Section 7.5.5)
- disposed assets (Section 7.5.6).

7.5.2 Initial RAB

IM 2.2.1 – 2.2.3

The CPP IM defines the roll-forward of RAB values from FY10. The RAB is determined at the start of FY10, and rolled forward from there. The asset base as at 1 April 2009 is termed the initial RAB, and the total opening RAB value in FY10 is termed the sum of initial RAB values.

Clauses 2.2.1 – 2.2.2 of the IMs set out the method for establishing the initial RAB, and clause 2.2.3 of the IMs defines the initial RAB values of assets included in the initial RAB.

The sum of our initial RAB values is $775m. The table below shows how this is made up by asset category.

Initial RAB values by asset category ($000)

	1 April 2009
Sub-transmission network including power transformers	128,373
Distribution network including distribution transformers	299,788
Switchgear (all voltages)	86,740
Low voltage distribution network	212,352
Supporting or secondary systems	25,769
Non system fixed assets	21,898
Total	**774,919**

Our report 'Initial Regulatory Asset Base as at 31 March 2009', issued 9 October 2012 sets out the derivation of our Initial RAB, consistent with Clauses 2.2.1 - 2.2.3 of the IMs. This has been independently reviewed by SKM. Their review is documented in their report 'Independent Engineer's Report on the Asset Adjustment Process of Orion NZ Ltd', dated 9 October 2012. Both of these reports are included in Appendix 14.

These reports were provided to the Commission in accordance with the 2012 s53ZD Notice request. In addition the Initial RAB values have been audited, as required by that Notice.

Initial RAB adjustments

While clause 2.2.1 permits adjustments to be made to the 2004 ODV valuation which underpins the initial RAB, we have not chosen to make any adjustments to this value. We have examined our 2004 ODV asset register and have concluded there are no material adjustments to be made. This is consistent with the 'optional' nature of clause 2.2.1.

We have made minor corrections to the value of asset additions included in the initial RAB during FY05 to FY09. These corrections relate to the asset categories to which the additions are assigned, in accordance with clause 2.2.1(2)(b)(iii). Asset categories are used for the purpose of assigning total asset lives for the purpose of calculating annual depreciation. This has a flow-on affect to the annual revaluation adjustment, as a result of the revised depreciation charges.

Previously asset additions for the period FY05-FY09 had been assigned to asset groups which were aggregates of a number of different asset categories. This aggregation introduced inherent errors to the RAB, by assigning the assumed 'group' asset life to all assets within the group. Our corrections now improve the accuracy of the Initial RAB, by assigning the FY05-FY09 asset additions to asset categories not groups. This asset category correction is summarised in Appendix B of our 9 October Initial RAB report.

The impact on the Initial RAB (after the inclusion of the finance during construction allowance at 31 March 2009) is a reduction in RAB, when compared to the previously disclosed value, of $0.769m. This equates to a reduction of 0.1% on the disclosed value. A table summarising the valuation impact is set out on page 15 of our 9 October report.

While the value impact is small, the corrected categorisation has additional benefits for our CPP proposal, in that we are better able to meet the reporting requirements for assets, where asset category information is required.

We identified one further error pertaining to our non system fixed asset values in our FY09 disclosures. Our land value was understated by $0.672m and this has now been corrected, and disclosed via our s53ZD Notice response.

7.5.3 Depreciation

IM 5.4.12 and 5.3.7 - 5.3.9

Depreciation is one of the inputs to the calculation of opening and closing RAB values, as discussed in Section 7.5.1. It is also a direct input to the calculation of BBAR.

IM requirements

Clause 5.4.12(1) and (2) of the IMs requires that a CPP proposal must provide:

- the sum of depreciation, for each type of asset
  - for which the proposed method of determining depreciation is the standard depreciation method
  - for which the proposed method of determining depreciation is something other than the standard depreciation method,

for each disclosure year of the CPP regulatory period.

As discussed in Section 7.5.1, we present information from FY10 to FY19.

Clause 5.4.12(3) of the IMs requires a CPP proposal to provide the following information for each type of asset for which the proposed method of determining depreciation is something other than the standard depreciation method:

- a description of the type of asset
- a description of the proposed depreciation method
- where the proposed asset life is different to the physical asset life, the proposed asset for the type of asset[24]
- where the proposed asset life for the type of asset is different to the physical asset life, the proposed remaining asset life
- forecast depreciation over the asset life for the type of asset, including details of all assumptions made
- forecast depreciation over the asset life for the type of asset determined in accordance with the standard depreciation method
- evidence to demonstrate that the proposed depreciation method including, where applicable, any proposed asset life different to the physical asset life, better meets the purpose of Part 4 of the Act than the standard depreciation method
- a description of any consultation undertaken with consumers on the proposed depreciation method, including
  - the extent of any consumer disagreement
  - the EDB's view in response.

In addition, clause 5.4.12(4) of the IMs requires that a CPP proposal include certain information for each asset for which a different physical asset life to the standard physical asset life is proposed.

Summary of depreciation

The table below shows the sum of depreciation, for each asset category, from FY10 to FY19. The total shows the amounts for total depreciation, defined in Part 1 of the IMs as the sum of depreciation for all assets, which are used to determine BBAR in Section 7.3.1. In Appendix 15 we include a more detailed table which discloses depreciation by asset type.

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[24] This text is from clause 5.4.12(3)(c) of the IMs, and appears to include a typographical error. We assume that the text after the comma is intended to read ‘the proposed asset **life** for the type of asset’.

Total depreciation by asset category ($000 nominal)	Current Period			Assessment Period		CPP Period				
	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Sub-transmission network	4,964	5,201	5,462	5,008	5,643	5,745	6,590	6,979	7,275	7,435
Distribution network	7,891	8,228	8,669	10,144	10,726	10,712	11,016	11,314	11,623	11,941
Switchgear	4,278	4,508	4,833	4,451	4,665	4,336	4,570	4,811	4,963	5,125
Low voltage distribution network	7,675	8,046	8,411	8,867	9,167	8,842	9,079	9,314	9,558	9,810
Supporting or secondary systems	1,795	1,915	1,981	1,468	1,858	1,823	1,949	2,067	2,206	2,314
Non system fixed assets	2,410	2,920	2,992	3,542	3,828	2,078	2,515	3,155	4,131	6,199
Total	**29,014**	**30,817**	**32,348**	**33,480**	**35,886**	**33,535**	**35,719**	**37,641**	**39,756**	**42,826**

These amounts comprise depreciation for assets where we use the standard depreciation method and others for which we use an alternative depreciation method during the CPP regulatory period. We separate out below: standard and alternative depreciation; describe our proposed alternative depreciation method; where we use it; and why we believe it better meets the purpose of Part 4 than the standard method.

Standard and alternative depreciation

Alternative depreciation is only able to be used within the CPP regulatory period. Accordingly all depreciation for FY10 – FY14 is calculated consistent with the standard method set out in the IMs. Within the CPP period, we propose to apply an alternative method to all assets commissioned from FY14 - FY18, with the exception of assets acquired from Transpower in that period. The reasons for this proposal are set out below.

The table below summarises the depreciation for all assets where the standard method applies, from FY10 – FY19. Appendix 15 includes a more detailed table which discloses this by asset type.

Standard depreciation by asset category ($000 nominal)	Current Period			Assessment Period		CPP Period				
	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Sub-transmission network	4,964	5,201	5,462	5,008	5,643	5,653	6,433	6,733	6,959	7,025
Distribution network	7,891	8,228	8,669	10,144	10,726	10,669	10,930	11,181	11,440	11,711
Switchgear	4,278	4,508	4,833	4,451	4,665	4,311	4,507	4,709	4,818	4,929
Low voltage distribution network	7,675	8,046	8,411	8,867	9,167	8,820	9,038	9,248	9,466	9,696
Supporting or secondary systems	1,795	1,915	1,981	1,468	1,858	1,790	1,876	1,936	2,022	2,060
Non system fixed assets	2,410	2,920	2,992	3,542	3,828	1,671	1,715	1,761	1,818	1,892
Total	**29,014**	**30,817**	**32,348**	**33,480**	**35,886**	**32,914**	**34,499**	**35,568**	**36,524**	**37,314**

The table below summarises the depreciation for all assets where the alternative method applies during the CPP period. Appendix 15 also includes a more detailed table which discloses this by asset type.

Alternative depreciation by asset category ($000 nominal)	Current Period			Assessment Period		CPP Period				
	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Sub-transmission network	-	-	-	-	-	92	157	246	316	410
Distribution network	-	-	-	-	-	42	87	133	182	230
Switchgear	-	-	-	-	-	25	63	102	145	196
Low voltage distribution network	-	-	-	-	-	22	41	66	92	115
Supporting or secondary systems	-	-	-	-	-	32	73	132	184	254
Non system fixed assets	-	-	-	-	-	407	800	1,394	2,313	4,307
Total	**-**	**-**	**-**	**-**	**-**	**621**	**1,221**	**2,073**	**3,232**	**5,512**

Asset lives

Depreciation is a function of asset lives which determine the period over which assets are depreciated. The standard depreciation method is a straight-line method. Asset lives for each asset type are determined in the IMs as per clause 2.2.8. This provides for standard asset lives for most assets in most circumstances, and a limited number of circumstances where asset lives may be adjusted.

For assets included in the initial RAB, assets are depreciated over their remaining lives. Asset additions are assigned a physical life which represents the total life over which depreciation is calculated. We use the same asset lives for our proposed alternative depreciation method as we use with the standard depreciation method.

In the two tables below we set out the remaining lives for assets in the initial RAB, and the physical asset life for commissioned assets, for each asset type. As the assets included in each asset type in the initial RAB have a range of remaining lives (which reflects the age profile of those assets) the remaining lives for each asset type are shown as weighted averages.

An exception to the above relates to assets which have a remaining life of less than five years at the end of FY14. Clause 2.2.8(4) of the IMs states that any asset in the RAB at the start of the CPP period must have a minimum remaining useful life on that date equal to the length of the CPP period (i.e.: five years). Therefore, we have adjusted the remaining life at the start of FY15 to five years for assets which have a remaining life of less than five years at the end of FY14.

Weighted average remaining life of initial assets

Asset type	Weighted average remaining life	Asset type	Weighted average remaining life
Sub-transmission network		***Switchgear***	
66 kV Overhead lines (concrete pole)	-	Surge Diverters (3ph, 66/33kV) / Air break isolators (66/33kV)	29.85
66 kV Overhead lines (wood pole)	38.41	Indoor circuit breakers and switchgear (66/33/11kV)	37.43
66 kV Overhead lines (towers)	8.79	Outdoor circuit breakers and switchgear (66/33/11kV)	19.01
66 kV Underground cables (PILC)	36.24	11kV Disconnectors & Dropout fuses	26.50
66 kV Underground cables (XLPE)	36.90	11kV voltage regulators	39.61
33 kV Overhead lines (wood pole)	43.05	11kV Circuit breaker/recloser & sectionalisers	32.28
33 kV Overhead lines (mixed construction)	28.67	11kV MSU and oil switches	27.52
33 kV Underground cables (PILC)	38.10		
33 kV Underground cables (XLPE)	35.20	***Low voltage distribution network***	
Pilot / Communications Circuits	21.67	LV Overhead lines (wood pole)	43.07
		LV Overhead lines (mixed construction)	29.11
Substations		LV Underground cables (PILC)	34.31
Zone sub land	-	LV Underground cables (XLPE)	34.08
Zone sub site development and buildings	33.03	Link Pillars & LV customer service connections	29.25
Power Transformers	36.49		
Protection (electromechanical)	24.12	***Supporting or secondary systems***	
Protection (digital)	18.20	Ripple Injection Plant	14.76
Outdoor Structure (concrete pole)	34.48	SCADA and communications	13.06
DC Supplies, batteries and inverters	8.60	Finance leases	32.27
Other items	22.01		
		Non system fixed assets	
Distribution network		Office Buildings	38.79
11 kV Overhead lines (wood pole)	43.08	Information and Technology Systems	3.41
11 kV Overhead lines (mixed construction)	31.54	Office Furniture and Equipment	4.08
11 kV Underground cables (PILC)	40.69	Tools, Plant and Machinery	4.34
11 kV Underground cables (XLPE)	38.14	Vehicles	3.88
Distribution sub land	-		
Distribution transformers (pole, 1ph/2ph/3ph)	31.86		
Distribution transformers (pad)	37.34		
Distribution substations mount (pole)	24.98		
Distribution substations mount (pad)	36.57		
Distribution substation mount (building & in customer building)	43.07		
Switchgear cabinet	35.61		

Asset lives for commissioned assets

Asset type	Total life	Source	Asset type	Total life	Source
Sub-transmission network			***Switchgear***		
66 kV Overhead lines (concrete pole)	60	Schedule A	Surge Diverters (3ph, 66/33kV) / Air break isolators (66/33kV)	35	Schedule A
66 kV Overhead lines (wood pole)	45	Sch A	Indoor circuit breakers and switchgear (66/33/11kV)	45	Sch A
66 kV Overhead lines (towers)	60	Sch A	Outdoor circuit breakers and switchgear (66/33/11kV)	40	Sch A
66 kV Underground cables (PILC)	70	Sch A	11kV Disconnectors & Dropout fuses	35	Sch A
66 kV Underground cables (XLPE)	55	Sch A	11kV voltage regulators	55	Sch A
33 kV Overhead lines (wood pole)	60	Sch A			
33 kV Underground cables (PILC)	45	Sch A	***Low voltage distribution network***		
33 kV Underground cables (XLPE)	70	Sch A	LV Overhead lines (wood pole)	60	Sch A
Pilot / Communications Circuits	55	Sch A	LV Overhead lines (mixed construction)	45	Sch A
			LV Underground cables (PILC)	70	Sch A
Substations			LV Underground cables (XLPE)	55	Sch A
Zone sub land	-	IMs 5.3.7(3)(a)	Link Pillars & LV customer service connections	45	Sch A
Zone sub site development and buildings	70	Sch A			
Power Transformers	45	Sch A	***Supporting or secondary systems***		
Protection (electromechanical)	40	Sch A	Ripple Injection Plant	20	Sch A
Protection (digital)	20	Sch A	SCADA and communications	15	Sch A
Outdoor Structure (concrete pole)	60	Sch A	Metering Systems	30	Sch A
DC Supplies, batteries and inverters	45	Sch A	Power factor correction plant	35	IMs 2.2.8(1)(e)(v)
Other items	20	Sch A	EDB-owned mobile substation	15	IMs 2.2.8(1)(e)(v)
			Other generation plant owned	15	IMs 2.2.8(1)(e)(v)
Distribution network			Easements	-	IMs 5.3.7(3)(a)
11 kV Overhead lines (wood pole)	60	Sch A	Spares	-	IMs 5.3.7(3)(a)
11 kV Overhead lines (mixed construction)	45	Sch A			
11 kV Underground cables (PILC)	70	Sch A	***Non system fixed assets***		
11 kV Underground cables (XLPE)	55	Sch A	Office Buildings *	41.56	IMs 2.2.8(1)(e)(iv)
Distribution sub land	-	IMs 5.3.7(3)(a)	Information and Technology Systems*	4.23	IMs 2.2.8(1)(e)(iv)
Distribution transformers (pole, 1ph/2ph/3ph)	45	Sch A	Office Furniture and Equipment*	6.68	IMs 2.2.8(1)(e)(iv)
Distribution transformers (pad)	55	Sch A	Tools, Plant and Machinery*	6.96	IMs 2.2.8(1)(e)(iv)
Distribution substations mount (pole)	45	Sch A	Vehicles *	5.86	IMs 2.2.8(1)(e)(iv)
Distribution substations mount (pad)	55	Sch A			
Distribution substation mount (building & in customer building)	70	Sch A			

Note: Weighted averages of individual asset lives

For all commissioned assets for which Schedule A of the IMs specifies a standard physical asset life, we use that standard physical asset life as the asset life.

We do not depreciate land, consistent with clause 5.3.7(3)(a) of the IMs, hence no asset life applies to land.

For commissioned assets where no standard physical asset life is specified in Schedule A of the IMs, we use the same asset life as that applying to a similar asset included in the initial RAB. This is consistent with clause 2.2.8(1)(e) of the IMs.

We note that we have two asset types in our commissioned assets for which no standard physical asset life is provided and where we have no assets of similar type in our initial RAB. For power factor correction plants, we use a physical asset life of 35 years. For mobile substations and generators we use 15 years. These represent our estimates of the appropriate physical asset lives for these assets. We have sought and obtained independent engineering review of these lives. Linetech Consulting supports the lives we have set out above. A copy of their review report is included as Appendix 16.

Commissioned assets include capital contributions, which are included as negative additions, ie: offset against the value of assets commissioned in the year received.

We depreciate capital contributions using an asset life of 56.4 years. This is the average of the IM standard physical asset lives for distribution assets (11kV and higher cables and lines, power transformers, distribution transformers) weighted by the sum of the initial RAB values for these asset types. As discussed in Section 7.5.5, we do not allocate capital contributions to specific assets, but rather treat them together as a contribution towards the network as a whole. We consider that in general they are used to fund distribution assets, and have ascribed the asset life for distribution assets for the purposes of calculating depreciation.

Which depreciation method is applied to which assets?

As stated above the standard depreciation method must be used outside of the CPP period. Within the CPP period we propose to use the standard depreciation method for:

- assets in the initial RAB
- assets we commission between FY10 and FY13
- assets acquired from another regulated supplier (regardless of year).

We propose to use an alternative depreciation method for all assets commissioned between FY14 and FY18,[25] excluding those acquired from another regulated supplier.

Determining depreciation for assets for which we use the standard method

Clause 5.3.7(2) of the IMs defines depreciation, under the standard depreciation method, as the result of the following formula:

$$depreciation = \frac{opening\ RAB\ value}{remaining\ asset\ life}$$

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[25] Note that assets commissioned in FY14 are first depreciated in the first year of the CPP, FY15, and assets commissioned in FY19 are not depreciated within the CPP regulatory period.

Assets in the initial RAB

In Section 7.5.2 we discussed the assets in the initial RAB. Each asset in the initial RAB has its own remaining life. In order to depreciate the RAB values of these assets, we use the remaining lives applicable to each asset. Weighted average lives for each type of asset are shown in the table above.

Assets commissioned between FY10 and FY13

In Section 7.5.5 we present the sum of the value of commissioned assets, from FY10 to FY13.

The asset lives used to determine depreciation differ by asset type, but are otherwise the same for all commissioning years. These are shown in the table above.

Assets acquired from another regulated supplier

In Section 7.5.5 we discuss our planned acquisitions of spur assets from Transpower. We set out the value of commissioned assets for these acquired assets in that section.

In order to depreciate acquired assets, we use the remaining lives for each asset on acquisition date. These are determined by Transpower, for the purpose of establishing the RAB value at acquisition date.

Each group of spur assets comprises a large number of individual assets, all with different remaining asset lives. The table below shows the weighted average remaining life for each group of acquired assets.

Weighted average remaining life of acuired assets at acquisition date

Acquisition year	Groups of assets acquired	Weighted average remaining life
FY13	Papanui	26.80
FY14	Springston	23.78
FY15	Middleton, Addington, Arthurs Pass, Castle Hill	24.15
FY16	Hororata, Bromley	31.27
FY17	Islington	16.08

Our proposed alternative depreciation method

As stated above, the standard depreciation method uses the following formula, as specified in clause 5.3.7(2) of the IMs:

$$depreciation = \frac{opening\ RAB\ value}{remaining\ asset\ life}$$

For the assets for which we propose to use the alternative method during the CPP period, we have used the following formula to determine depreciation:

$$depreciation = \frac{opening\ RAB\ value}{remaining\ asset\ life^{1.6}}$$

We propose to use this alternative deprecation method to better match the depreciation profile with the expected demand for those assets over the CPP regulatory period. This assists us to smooth the price increases proposed in this CPP application as it defers depreciation within the CPP period relative to the standard method.

Clause 5.3.8(2) of the IMs states that an alternative method can only be used to determine depreciation during the CPP regulatory period, not before. Assets in the initial RAB or commissioned before FY14 are (at least partially) depreciated prior to the start of the CPP regulatory period. We have retained the standard depreciation method for those assets. The vast majority of these assets were commissioned for reasons other than in response to the earthquakes. It is a simple approach to maintain the standard depreciation method once it has been applied in prior years.

However, much of our investment during FY14 to FY18 is in direct response to the earthquakes. It enables us to restore our network resilience and move back towards our target service levels. We therefore propose to modify the depreciation on these new assets as best we can to match the Canterbury recovery phase. We believe that this is an appropriate alternative as it recognises that demand for our services will recover over an extended period, including the five years that the CPP will apply to us. Our alternative approach pushes cost recovery in to the future and therefore into the post recovery period.

The effect of using this alternative method is to reduce the depreciation in the early years of the asset life, and increase it in the later years (relative to the standard method). Our proposed alternative method is specified to be the reverse of the “diminishing value” approach (where depreciation is largest in the early years), which is a common approach to calculating depreciation in other situations such as tax depreciation and for determining insurance values.

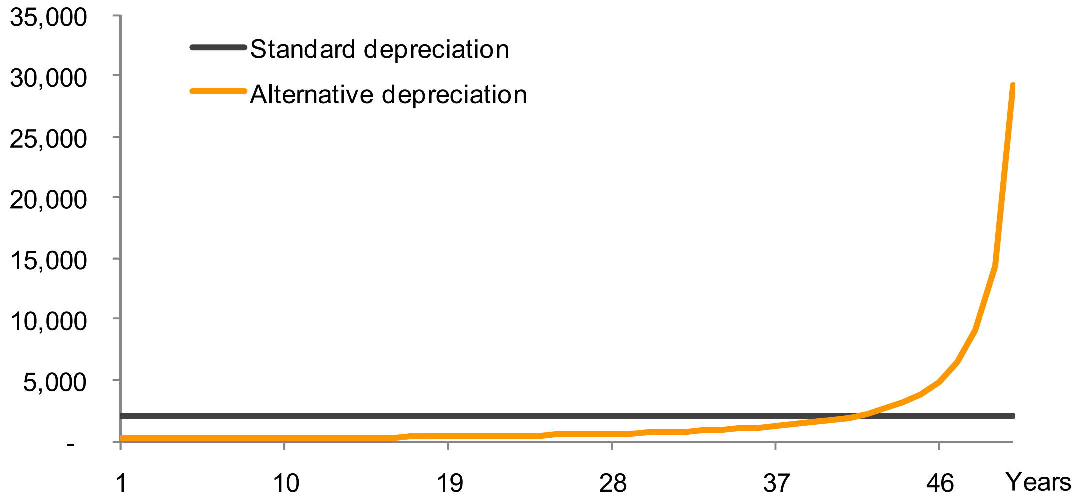
The two charts below show, using an illustrative example, the difference between the standard depreciation method and our proposed alternative method over the total life of an asset. This example uses a $100,000 asset with a life of 50 years, and excludes revaluations.

The first chart shows the depreciation over the asset’s life under each method. The second shows depreciation plus the return on capital.

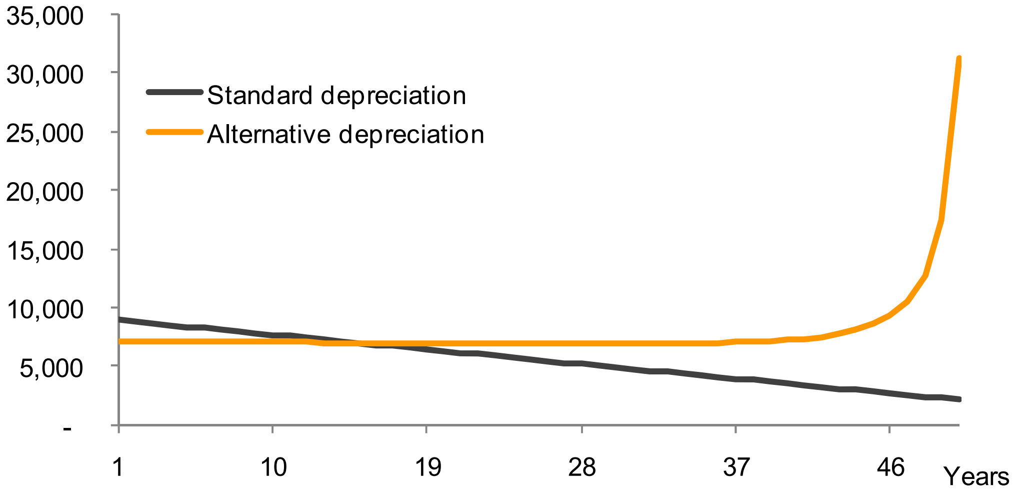
Depreciation is lower in the early years under our alternative method, and increases exponentially over the life of the asset. This contrasts with the standard method where deprecation is constant. The return on capital is higher under our alternative method, due to the higher RAB. The higher depreciation and return compensate for the fact that the depreciation occurs later – the changes are PV-neutral.

As stated above we are only able to apply this alternative method for the five year CPP regulatory period. After that time, assuming we move back to a DPP, we will revert back to the standard depreciation method. Accordingly the extreme tail end of the alternative method illustrated in the charts below will not apply.

Annual amount of depreciation on a $100,000 commissioned asset ($ nominal)



Annual amount of depreciation and return on capital on a $100,000 commissioned asset ($ nominal)



Under the alternative method the convexity of the depreciation line can be altered by changing the index value on the remaining asset life term. A lower figure makes the line less convex, with a value of 1 giving a straight line (the standard method). A higher figure makes the line more convex, and increases depreciation in the later years. We use 1.6 because this generates a function for depreciation that most closely resembles the reverse of the diminishing value depreciation function – as shown in the chart above. We note that this is a matter of judgement, and alternative values of similar order of magnitude could be considered reasonable.

As with the standard depreciation method, our proposed alternative method uses the physical asset lives as the asset lives for each asset. For no asset are we proposing to use an asset life other than the corresponding physical asset life, nor a physical asset life which differs from a standard physical asset life.

We note that following the end of the CPP regulatory period, depreciation must be determined using the standard depreciation method. The post-CPP amounts for depreciation will be higher than they otherwise would be, due to lower depreciation in the CPP period.

Alternative depreciation

The table below shows the sum of depreciation during the CPP period, by asset category, using the alternative approach.

Alternative depreciation by asset category (assets with alternative depreciation) ($000 nominal)	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Sub-transmission network	92	157	246	316	410
Distribution network	42	87	133	182	230
Switchgear	25	63	102	145	196
Low voltage distribution network	22	41	66	92	115
Supporting or secondary systems	32	73	132	184	254
Non system fixed assets	407	800	1,394	2,313	4,307
Total	**621**	**1,221**	**2,073**	**3,232**	**5,512**

For comparison, the table below shows the same information for the same assets, calculated using the standard depreciation method.

Standard depreciation by asset category (assets with alternative depreciation) ($000 nominal)	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Sub-transmission network	824	1,364	2,133	2,611	3,242
Distribution network	452	910	1,376	1,852	2,294
Switchgear	242	587	937	1,308	1,742
Low voltage distribution network	229	422	671	909	1,118
Supporting or secondary systems	109	268	481	631	851
Non system fixed assets	1,364	2,095	2,915	3,678	4,738
Total	**3,219**	**5,646**	**8,512**	**10,989**	**13,984**

The table below shows the difference between the two methods (standard depreciation less alternative depreciation).

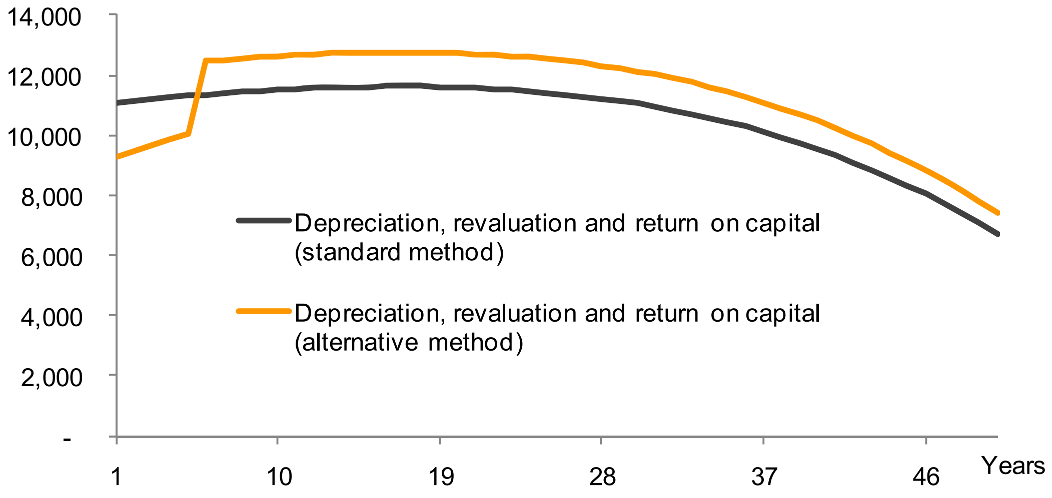
Difference between depreciataion methods (assets with alternative depreciation) ($000 nominal)	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Sub-transmission network	732	1,207	1,887	2,294	2,832
Distribution network	409	823	1,243	1,670	2,064
Switchgear	217	524	835	1,163	1,545
Low voltage distribution network	206	381	604	818	1,003
Supporting or secondary systems	77	196	349	447	597
Non system fixed assets	957	1,295	1,521	1,365	431
Total	**2,598**	**4,425**	**6,439**	**7,757**	**8,472**

Present value equivalence

Our proposed alternative method involves lower depreciation in the early years and greater depreciation in the later years of the asset's life, relative to the standard method. However, over the total life of each asset, the outcome is equivalent in present value terms.

In the chart below, we extend the illustrative example used above to show the difference between the two depreciation methods when applied to an asset which we commission in FY14, and for which the first five years of its deprecation coincide with the CPP regulatory period. We also revalue the asset each year (using the CPP inflation rate) which is the same as the method which applies for this CPP. The chart shows the sum of depreciation, revaluation and return on capital for the same asset used above, for two depreciation scenarios. The alternative method is assumed to revert back to the standard method at the end of the CPP period. The chart shows that under the alternative method, the building block costs are lower during the CPP regulatory period, and then slightly higher thereafter. The present values of the two series are the same.

Annual amount of depreciation , revaluation and return on capital combined on a $100,000 commissioned asset - standard depreciation after 5 years ($ nominal)



Alternative depreciation method better meets the purpose of Part 4

The reason we are proposing this alternative depreciation method is to reduce the initial price changes that our consumers will face as a result of this CPP proposal. This CPP proposal involves a step increase in prices for our consumers, and we have sought mechanisms within the CPP IMs to minimise the impact on them, while at the same time allowing us to provide an electricity distribution service which is fundamental to Canterbury's economic and social well being.

We reiterate that in determining our proposed price path, and in particular the X factor, we gave careful consideration to the impact on our consumers of price increases, and have sought to mitigate these impacts where possible (as discussed in Sections 7.1 and 7.2).

Our proposed alternative depreciation method lowers BBAR during the CPP regulatory period. Non-standard depreciation is the only mechanism we have for altering BBAR (for a given expenditure plan).

Average prices will be lower in the CPP regulatory period and higher thereafter. In effect, it is a trade-off of "revenue now versus revenue later".

However, we believe that the profile of our proposed depreciation recovery is logical because it is better matched to the recovery of our network resilience and performance, and the economic recovery of Canterbury and hence the demand for our services.

Customer consultation

Our consumer consultation material, which is included in our CPP application, set out our proposal to defer depreciation during the CPP period in order to minimise price increases. This aspect of our proposal was not directly responded to.

A summary of our consultation responses is provided in the CPP application. However as a general theme the respondents to the consultation material were supportive of the work we plan to do to restore the network within the CPP period, and for us to limit price increases where possible. We believe that our proposed depreciation approach is consistent with this feedback.

Adjusted depreciation

Adjusted depreciation is defined in Part 1 of the IMs as total depreciation for all assets, calculated as if no amount of revaluations is included in the calculation of any opening RAB value following the determination of the initial RAB.

Adjusted depreciation is an input to the calculation of amortisation of revaluations and depreciation temporary differences, as set out in Sections 7.6.5 and 7.6.7. These are required in order to derive the regulatory tax allowance building block which is discussed in Section 7.6.

We derive the amounts for adjusted depreciation in the same way as we have for depreciation set out above – except that we assume revaluations are nil in each year from FY10. Our adjusted depreciation therefore reflects our proposed alternative depreciation method for assets commissioned from FY14 onwards.

The table below shows the amounts for adjusted depreciation from FY10 to FY19. We also show the amounts for total depreciation for comparison. Without revaluations, the asset values are lower and hence adjusted depreciation is lower than depreciation in all but FY10. The values are the same in this year as the revaluations are year-end adjustments, and their impact on depreciation appears for the first time in FY11 (following the year-end adjustment in FY10).

Adjusted depreciation ($000 nominal)	Current Period			Assessment Period	
	FY10	FY11	FY12	FY13	FY14
Total depreciation	29,014	30,817	32,348	33,480	35,886
Adjusted depreciation	29,014	30,173	30,902	31,587	33,429

	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Total depreciation	33,535	35,719	37,641	39,756	42,826
Adjusted depreciation	30,750	32,100	33,173	34,351	36,296

Other alternative depreciation methods considered

As discussed above, we propose to use an alternative depreciation method for all assets commissioned from FY14, which has the effect of reducing depreciation for these assets during the CPP regulatory period.

We also considered further alternative depreciation methods. In particular, we considered the following:

- fully depreciating the major assets which were destroyed in the earthquakes (one 66kV cable and the Brighton and Pages substations) within the CPP regulatory period
- applying a physical asset life of three years, as opposed to the standard physical asset life stated in the IMs, for the temporary 66kV overhead lines which we commissioned in response to the earthquakes which, under our resource consent, we have to decommission after three years.

Each of these alternatives would have the impact of accelerating depreciation during the CPP period, relative to the standard method. We believe that each case is justifiable on the basis that the suggested alternative lives better reflect the usage of the assets involved.

However accelerated depreciation necessarily brings revenue forward, and makes prices higher during the CPP regulatory period. This would impose additional costs on consumers at a time when demand is still recovering. We believe that it is more consistent with the long-term interests of consumers that these costs are shared over the assumed standard physical life of the assets, consistent with the remainder of the asset base.

7.5.4 Revaluation

IM 5.4.13 and 5.3.10

The RAB is presented in nominal terms (along with the rest of the inputs to BBAR and the price path). To ensure it retains its real value over time, the RAB is revalued each year in accordance with changes to the inflation rate.

IM requirements

Clause 5.4.13 of the IMs requires that a CPP proposal must provide:

- the sum of opening RAB values (ie total opening RAB value)
- forecast CPI for the last quarter of the disclosure year
- forecast CPI for the last quarter of the preceding disclosure year
- revaluation rate

for each disclosure year after the last disclosure year in which a disclosure has been made pursuant to an ID determination, or for each disclosure year after FY09 where no such disclosure has been made, until the last disclosure year of the next period.

As discussed in Section 7.5.1, we present information from FY10 to FY19.

We also provide amounts for the total revaluation building block, which is used to determine the amounts for BBAR presented in Section 7.3.1.

Opening RAB values and revaluation rate

The table below shows total revaluation, and the inputs to its derivation, from FY10 to FY19. The table includes total opening RAB value, asset disposals (which are deducted from opening RAB for the purpose of the revaluation calculation) forecast CPI for the last quarter of the disclosure year, forecast CPI for the last quarter of the preceding disclosure year, and the revaluation rate.

Revaluation (nominal)	Current Period			Assessment Period		CPP Period				
	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Total opening RAB value ($000)	774,919	794,911	816,257	844,085	902,912	973,437	1,054,458	1,140,168	1,197,063	1,259,945
Disposed assets	-	-	-	-	15,739	-	-	-	-	-
Forecast CPI for the last quarter of the disclosure year	1,097	1,146	1,164	1,185	1,206	1,234	1,261	1,288	1,316	1,345
Forecast CPI for the last quarter of the preceding disclosure year	1,075	1,097	1,146	1,164	1,185	1,206	1,234	1,261	1,288	1,316
Revaluation rate	2.05%	2.42%	1.57%	1.80%	1.77%	2.32%	2.17%	2.17%	2.17%	2.17%
Total revaluation ($000)	**15,854**	**19,213**	**12,827**	**15,207**	**15,678**	**22,543**	**22,755**	**24,618**	**25,847**	**27,123**

Total revaluation is defined in Part 1 of the IMs as the sum of revaluation for all assets.

Clause 5.3.10(2) and (3) defines revaluation, for an individual asset, as the opening RAB value multiplied by the revaluation rate, unless the asset is disposed of or lost in the disclosure year or where the asset's physical life at the end of the disclosure year is nil, in which case it is nil.

Total revaluation in the table below is slightly less than the product of total opening RAB value (less disposals) and the revaluation rate, because assets which are fully depreciated within the year are not revalued.

We described how the amounts for total opening RAB are determined in Section 7.5.1.

Clause 5.3.10(4) of the IMs defines revaluation rate as forecast CPI for the quarter that coincides with the end of the disclosure year divided by forecast CPI for the quarter that coincides with the end of the preceding disclosure year, less one.

Forecast CPI is defined in Part 1 of the IMs as the forecast annual percent change in the headline CPI contained in the current RBNZ Monetary Policy Statement. For each quarter subsequent to the forecasts provided, it is the arithmetic average of the values forecast in the most recent four quarters of which a forecast has been made in the Monetary Policy Statement. These values are shown above. The Monetary Policy Statement released in September 2012 has been used for this proposal.

7.5.5 Commissioned assets

IM 5.4.14 and 5.3.11

Commissioned assets are new assets added to the regulatory asset base. The value of commissioned assets in a given year is added to the RAB in that year.

Clause 5.3.11 of the CPP IM defines the forecast value of a commissioned asset as the forecast cost of the asset to Orion determined by applying GAAP on its forecast commissioning date, with a number of exceptions, as set out in clause 5.3.11.

IM requirements

Clause 5.4.14(1) of the CPP IM requires that a CPP proposal must provide:

- the sum of value of commissioned assets, separately for each of the following groups of assets:
  - assets acquired from a related party or transferred from a part of Orion that supplies unregulated services
  - assets acquired from another regulated supplier (and used by that supplier to supply electricity distribution services) or transferred from a part of Orion that supplies other regulated services
  - network spares
  - all other commissioned assets,

for each disclosure year after the last disclosure year in which a disclosure has been made pursuant to an ID determination, or for each disclosure year after FY09 where no such disclosure has been made, until the last disclosure year of the next period.

As discussed in Section 7.5.1, we present information from FY10 to FY19.

Clause 5.4.14(2)(a) of the IMs requires that a CPP proposal must provide all data, information, calculations and assumptions used to derive values of commissioned assets from the data provided in the capex forecast.

Clause 5.4.14(2)(b) of the IMs requires that a CPP proposal must provide, for any commissioned assets where capital contributions are taken into account in its value, the amount of capital contributions, with respect to asset types and quantities, and policies relevant to capital contributions.

Clause 5.4.14(3) of the IMs requires that a CPP proposal must provide, for any asset acquired from a related party, information about the related party and the relationship with Orion.

Clause 5.4.14(4) of the IMs requires that a CPP proposal must provide, for any asset acquired from another regulated supplier, the name of the vendor, a description of each asset, and the forecast closing RAB value of the asset in the year of acquisition.

Summary of amounts for the value commissioned assets

The table below shows the value of commissioned assets, for those acquired from a related party, those acquired from another regulated supplier, network spares, and all other commissioned assets, from FY10 to FY19.

Comissioned assets ($000 nominal)	Current Period			Assessment Period		CPP Period				
	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Assets acquired from a related party	13,002	14,393	17,774	-	-	-	-	-	-	-
Assets acquired from a regulated supplier	-	-	-	4,188	2,700	16,784	9,419	1,198	-	-
Network spares	-	-	-	-	-	-	-	-	-	-
Other commissioned assets	20,150	18,558	29,575	72,912	103,698	75,229	89,255	68,720	76,791	59,604
Total value of commissioned assets	**33,152**	**32,951**	**47,349**	**77,100**	**106,398**	**92,013**	**98,674**	**69,918**	**76,791**	**59,604**

Assets acquired from a related party

We have acquired assets from Connetics, our related party contractor, during the current period. Information on the amount of our capex undertaken by Connetics between FY10 and FY12 is set out in Sections 8.5.5 and 9.25. We have assumed that the historical value of commissioned assets associated with Connetics is the same as the amount of capex performed by them in each year. Our asset recording processes are not set up to provide commissioned asset values by contractor. This is a reasonable assumption, consistent with our forecasts for commissioned assets, that the majority of our capex is commissioned in the same year it is undertaken.

As we tender our full capital works programme, it is not possible to forecast which proportion of our planned capex (and hence commissioned assets) will be provided by Connetics. We have therefore not included any values for assets acquired from related parties for the assessment period and the CPP regulatory period. We expect that some future capex will be undertaken by Connetics.

We discuss this in more detail in Section 8.5.5.

We have considered the requirements of the amended CPP IM clause 5.3.11(6) for the value of assets forecast to be commissioned from a related party. This amendment was introduced in June 2012, and specifies methods for determining the value of assets to be included in the RAB, where they have been acquired from a related party. As noted above, it is not possible to forecast this amount.

We have considered the new methods in light of our historical commissioned assets acquired from Connetics. We have included these assets at cost, determined in accordance with GAAP, as permitted by clause 2.2.11(5)(c), for FY10-FY12. Evidence to support this conclusion has been provided to the Commission (by way of response to the 27 August 2012 s53ZD Notice) in respect of the FY10 year on the basis of our tendering processes. As these processes will continue throughout the CPP regulatory period it is reasonable to assume that all capex can be included at cost, as any undertaken by Connetics will be awarded as the result of competitive tender. This is consistent with 5.3.11(6)(c) of the amended CPP IM.

Assets acquired from another regulated supplier

In Sections 8 and 9 we describe how we have acquired one set of spur assets from Transpower during FY13, and how we forecast that we will acquire more spur assets between FY14 and FY17 (one set each year). Each acquisition comprises a large number of individual assets.

Some of the assets acquired are already included in our RAB as finance leases.

Clause 5.3.11(1)(e) of the CPP IM states that the value of a commissioned asset which is acquired from another regulated supplier is limited to its value determined in accordance with the input methodologies applicable to the services supplied by that supplier on the forecast commissioning date. This means that the value of the acquired spur assets is to be Transpower's RAB value. As the Transpower spur assets which are covered by finance leases are included in our RAB, we make no adjustment at acquisition date (ie: we include no additional commissioned assets in the RAB). The values of acquired assets stated in this section exclude any values for finance leases – they are new assets to be added to our RAB.

Transpower has provided us with forecasts of RAB values at the dates of acquisition. We use this data to derive our forecast values of acquired commissioned assets.

The table below shows the value of commissioned assets, for acquired assets in each year from FY13 to FY17, shown by asset type.

Acquired assets ($000 nominal)	Assessment Period		CPP Period		
Asset type	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**
66kV overhead lines (towers)	704	300	1,562	-	-
Pilot/commuincation circuits	12	7	1,314	161	293
Zone sub land	773	208	4,001	438	-
Zone sub site development and buildings	704	448	2,183	1,766	238
Power transformers	796	538	3,421	2,110	228
Protection (digital)	265	570	930	703	76
Outdoor structure (concrete pole)	265	179	692	703	76
DC Supplies, batterries and inverters	133	90	346	352	38
Outdoor circuit breakers and switchgear (66/33/11kV)	265	179	1,206	2,017	76
Indoor circuit breakers and switchgear (66/33/11kV)	265	179	692	1,117	76
Communications equipment	4	2	438	54	98
Total	**4,188**	**2,700**	**16,784**	**9,419**	**1,198**

Network spares

We have not explicitly included any network spares purchases in the capex forecast, hence there are no network spares commissioned for the RAB. Our replacement programme implicitly includes the replacement of spares.

This is discussed in more detail in Section 9.15.

All other commissioned assets

Historical values

We source the amounts for the value of commissioned assets in FY10 to FY12 from the additions that we have made to our fixed asset register in those years. As discussed above, some of this is procured from Connetics, with the remaining included as “all other commissioned assets”.

Derivation from capex forecast

The capex detailed in Sections 8 and 9 includes both assets acquired from another regulated supplier and other commissioned assets.

The forecast value of commissioned assets is defined in clause 5.3.11 of the CPP IM. The default method is to use the forecast cost of the asset to Orion determined by applying GAAP on its forecast commissioning date. None of the exceptions to this rule, as specified in clause 5.3.11, apply to the assets in the capex forecast, other than the instances noted above.

Deriving a forecast for the value of commissioned assets from our capex forecast is difficult. Capex is spent over a period of time, and each asset is commissioned after the expenditure is incurred. Most of our assets will be commissioned in the financial year that the capex is incurred. Much of our capex is part of ongoing programmes (for example asset replacements).

There is typically a delay between when the physical asset is commissioned and it is entered into the asset register, reflecting completion of project documentation. There is usually a small lag, which, at year end shows in our works under construction balance.

Some larger projects will span a number of years, and this capex also shows in our works under construction balances until the year they are commissioned.

For the majority of our capex, we make the assumption that all the assets are commissioned in the financial year in which the capex is incurred. In these cases, the value of commissioned assets equals the relevant (nominal) capex in that year. For a small number of major projects, we know that the capital expenditure is forecast to span multiple years. In these cases, we assume the asset is commissioned in the final year of capex, and the value of commissioned assets is the sum of all capex from the relevant prior years plus the forecast financing costs (as specified under GAAP, and in clause 5.3.11(3)(a) of the CPP IM).

This method for forecasting the value of commissioned assets is necessarily a simplification. In reality, since capex is incurred throughout a year, much of the capex spent in the last month or two of the year will be commissioned in the following year, even for small projects. But since this will be the case for all years, assuming that the majority of capex incurred is commissioned in that year derives a reasonable estimate of the value of commissioned assets. Our forecast works under construction balances reflect the lags between capex and commissioning that we expect over the forecast period.

To estimate the cost of financing which we apply to the major projects which are expected to span more than one year, we use the cost of capital used to determine BBAR during the CPP regulatory period as the financing rate. This is consistent with clause 5.3.11(3)(b) of the CPP IM, which specifies that the cost of financing must be calculated using a rate no greater than the 75th percentile estimate of WACC published most recently prior to the disclosure year in question.

The table below shows the major projects for which the capital expenditure is spread over more than one year. It shows the years of capex, the commissioning year, the total capex, estimated financing costs, and the value of commissioned assets. We note that for some capex, the assets are not commissioned during the CPP regulatory period. Accordingly, the assets do not enter the RAB and hence have no commissioned value for the CPP.

Projects with a different commissioning year date to capex year date ($000)						
CPP Reference	**Projects**	**Year of capex**	**Commissioning year**	**Nominal capex**	**Financing costs**	**Value of commissioned asset**
CPP1	Land acquisition for Marshland substation	2014	2015	515	36	551
CPP1	Marshland to Waimakiriri 66kV link	2015	2016	11,559	800	12,359
CPP2	Bromley to Dallington 66kV link stage 1	2013	2014	1,620	142	1,762
CPP3	Land acquisition for Templeton substation	2015	2022	106		
CPP3	Land acquisition for Shands 66kV switchyard	2016	2017	110	8	118
CPP4	Land acquisition for Milton 66kV switchroom	2015	2016	532	37	569
CPP4	Land acquisition for HoonHay 66kV switchroom	2016	2025	221		
CPP5	Awatea substation land remediation	2014	2025	258		
CPP7	Land acquisition for Burnham substation	2014	2015	258	18	275
CPP7	Land acquisition for Rossendale substation	2014	2025	258		
CPP8	Land acquisition for Creyke 66kV substation	2017	2018	285	20	304
CPP11	Land acquisition for Norwood substation	2018	2019	294	20	314
CPP15	Land acquisition for Southbridge substation	2017	2018	114	8	122
CPP20	Ground Fault Neutralisers - 4 units	2013	2014	532	47	578
CPP60	Head office building	2013	2014	14,900	1,307	16,207

The tables below show how the values of commissioned assets are derived from the amounts of nominal capex. The first table shows capex and the value of commissioned assets, for FY13 to FY19, for projects where capex is assumed to span multiple years. The second table shows capex and the value of commissioned assets for projects where we assume all capex is incurred in the same year as the commissioning date.

The value of capex and comissioned assets - assets where capex spans multiple years ($000 Nominal)	Current Period			Assessment Period	
	FY10	**FY11**	**FY12**	**FY13**	**FY14**
Total capex				17,051	1,288
Sum of value of commissioned assets				18,784	18,547

	CPP Period				
	FY15	**FY16**	**FY17**	**FY18**	**FY19**
Total capex	12,198	331	399	294	-
Sum of value of commissioned assets	826	12,928	118	426	314

The value of capex and comissioned assets - all other assets ($000 Nominal)	Current Period			Assessment Period	
	FY10	**FY11**	**FY12**	**FY13**	**FY14**
Total capex				60,516	94,964
Sum of value of commissioned assets				60,516	94,924

	CPP Period				
	FY15	**FY16**	**FY17**	**FY18**	**FY19**
Total capex	94,510	91,869	74,455	79,526	61,920
Sum of value of commissioned assets	94,510	91,869	74,455	79,526	61,920

We also have some assets which we expect to commission in FY13 where some capex was incurred prior to FY13. We add to commissioned assets for FY13, the value of capex incurred prior to FY13, where we expect to commission the assets in FY13, adjusted for financing costs.

The two tables above exclude any adjustment for (ie are gross of) capital contributions.

Capital contributions

Clause 5.3.11(1)(h) of the IMs states that, for an asset in respect of which capital contributions are received, the cost of the asset (as used to determine the value of commissioned asset) should be reduced by the amount of the capital contributions.

The capital contributions that we receive are designed to help fund a number of different assets. The trigger for the receipt of capital contributions is typically a connection to the network rather than the incurrence of the upstream capital expenditure which they ultimately fund. Other contributions are received towards the cost of relocation of existing assets, including overhead to underground conversion. Our connections and extensions policy (NW70.00.45) sets out how our contributions are determined.

We note that the underlying intent of clause 5.3.11(1)(h) is that capital contributions reduce the value of additions to the RAB. Accordingly, we treat all capital contributions as negative commissioned assets in the year they are received.

In Section 9.16 we outline our policy for deriving capital contribution revenue. We collect contributions for underground conversions (refer CPP50) and for connections and extensions (refer CPP53). The proportion of the total costs which are funded through capital contributions is different for each.

For FY10 to FY12, we use actual values of capital contributions received. These are shown in the table below.

Our forecasts are derived from our FY13 budget and our forecasts of connection/extension and undergrounding expenditure throughout the CPP period. Much of our forecast underground conversions are driven by major NZTA projects. Developer-initiated undergrounding of some 66kV assets is also expected. Our council shareholders have agreed that it is their responsibility to determine the priority for discretionary undergrounding projects. A portion of our system reinforcement and safety and improvement projects will also continue to include undergrounding of overhead reticulation.

The connections and extensions work mainly involves installing 11kV and low voltage cables, transformers, switchgear and other related assets. Consumers seeking new connections contribute the costs of the activity in accordance with our connections and extensions policy (NW70.00.45).

Approximately 60% of the total project cost of underground conversions is funded by capital contributions, although this varies by project type. For connections and extensions, this figure is around 13%. We expect that these proportions will continue during the CPP regulatory period.

The table below shows the aggregated historical amounts for capital contributions from FY10 to FY12 and our forecast of capital contributions from FY13 to FY19 by source.

Capital Contributions ($000 nominal)	Current Period			Assessment Period		CPP Period				
	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Connections and extensions	1,364	1,269	1,436	800	1,935	2,049	2,173	1,975	1,816	1,819
Undergrounding	1,478	1,539	2,663	1,400	5,138	1,274	3,951	2,681	1,345	812
Upper South Island load management system	534	-	-	-	-					
Total	**3,376**	**2,808**	**4,099**	**2,200**	**7,073**	**3,323**	**6,123**	**4,656**	**3,161**	**2,631**

Capital contributions range between $2.6m and $6.1m annually over the CPP regulatory period, which represents around 4% - 6% of the total value of commissioned assets.

In Section 7.5.3 we describe how our method for depreciation of capital contributions is based on the asset lives of our upstream assets.

7.5.6 Asset disposals

IM 5.4.15

Disposed assets are assets which are lost, sold or transferred, and which are removed from the RAB. This occurs in the year of disposal, by reducing the RAB by the opening value of the asset disposed of.

IM requirements

Clause 5.4.15(1) of the CPP IM requires that a CPP proposal must provide:

- the sum of unallocated opening RAB values and the sum of opening RAB values, separately for:
  - assets likely to sold to a related party or transferred to another part of Orion
  - all other disposed assets

for each disclosure year after the last disclosure year in which a disclosure has been made pursuant to an ID determination, or for each disclosure year after FY09 where no such disclosure has been made, until the last disclosure year of the next period.

As discussed in Section 7.5.1, we present information from FY10 to FY19.

Clause 5.4.15(2) of the IMs requires that a CPP proposal must provide, for each asset forecast to be disposed, information pertaining to other parties involved in the disposal.

Summary of RAB values of disposed assets

The table below shows the sum of the opening RAB values for disposed assets from FY10 to FY19.

Sum of opening RAB values for disposed assets ($000 nominal)	Current Period			Assessment Period		CPP Period				
	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Assets sold to a related party or another part of Orion	-	-	-	-	-	-	-	-	-	-
All other disposed assets	-	-	-	-	15,739	-	-	-	-	-

We note that the unallocated opening RAB values for disposed assets are the same as the opening RAB values in the table above. As we explain in Section 7.4.2, all of the assets we are forecasting to dispose of are directly attributable to electricity distribution services.

Forecast disposals

Our major disposal before the end of the CPP regulatory period is the group of assets that comprise our Armagh Street head office site. These will be sold, but not to a related party or another part of Orion.

Our head office was damaged in the earthquakes. It has been subsequently demolished, although other support buildings remain on site. We are currently working from these buildings. In FY14 we will move to new headquarters at Wairakei Road. We therefore forecast that we will dispose of the Armagh St site during FY14.

CERA has indicated that our current site will form part its new CBD frame. We therefore anticipate that CERA will ultimately be the other party involved in this disposal.

The Armagh St assets include both buildings and land. The table below shows the opening RAB values in FY14 for the Armagh St assets.

Armagh Street disposal - opening RAB values ($000 nominal)	Assessment Period
Asset types	FY14
Armagh St buildings	2,302
Armagh St land	7,257
Additional corporate land	6,181
Total	**15,739**

We note that our Armagh street zone substation will remain on this site. The value of the substation assets therefore remain in the RAB and do not form part of this disposal.

These opening RAB values are determined in accordance with Part 5, Subpart 3, Section 2 of the IMs. They are included in the amounts shown in Section 7.5.1. The opening RAB values are a function of the Initial RAB value (or value of commissioned asset if not in Initial RAB), revaluation prior to the year of disposal and depreciation prior to the year of disposal.

The value of disposed assets in FY14, as shown in Section 7.5.1, is slightly lower than the opening RAB values of the disposed assets in FY14. This is because the disposed value also includes the impact of depreciation in the year of disposal.

We expect that we will sell the Armagh St assets for less than the sum of their RAB values. We expect to sell the assets for $7.915m, the value determined in their most recent (2012) valuation. We are hence forecasting a loss on sale of the Armagh St assets, which is incorporated in our forecast of other regulated income. The RAB is reduced by the opening RAB value, less depreciation, in the year of disposal.

Lastly, we note that our forecast for other regulated income includes estimates of future gains on sale of vehicles and other non-system assets. We assume that these assets are sold at the end of their useful lives, and hence are fully depreciated. There is no adjustment to the RAB required.

7.5.7 Works under construction

IM 5.4.16 and 5.3.12

As previously noted some assets involve capital expenditure which spans multiple years. Any such capex is not added to the RAB until the corresponding asset is commissioned. At the end of a year, any capex which has been spent, or is forecast to be spent, but where the asset has not been commissioned is held as works under construction.

Works under construction does not directly affect the RAB (or BBAR), but its value eventually becomes part of the value of commissioned assets in future years.

IM requirements

Clause 5.4.16 of the IMs requires that a CPP proposal must provide values for:

- opening works under construction
- sum of capital expenditure
- sum of the value of commissioned assets and forecast commissioned assets (to the extent that these assets are included in closing RAB values)
- sum of closing works under construction,

for each disclosure year after the last disclosure year in which a disclosure has been made pursuant to an ID determination, or for each disclosure year after FY09 where no such disclosure has been made, until the last disclosure year of the next period.

As discussed in Section 7.5.1, we present information from FY10 to FY19.

Works under construction roll-forward

Clause 5.3.12(1) and (2) of the IMs defines opening works under construction as closing works under construction of the preceding disclosure year, and specifically that the first day of the next period (ie: FY13) amount for opening works under construction is the amount of expenditure incurred on works under construction as of the first day of the FY13 disclosure year (including financing costs).

Clause 5.3.12(3) of the IMs defines closing works under construction as opening works under construction plus the sum of capital expenditure less the sum of commissioned assets and forecast commissioned assets.

The table shows opening and closing works under construction, the sum of capital expenditure, and the sum of the value of commissioned assets, from FY10 to FY19. The works under construction balance increases from $14m at the start of FY10 to $29m by the end of FY12, as a result of our capital programme in response to the earthquakes. As these projects are commissioned, the works under construction reduces again, and we are forecasting it to be around $13m at the end of the CPP period.

Works under construction ($000 nominal)	Current Period			Assessment Period		CPP Period				
	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Opening works under construction	13,536	20,002	23,135	29,086	28,868	13,144	24,605	12,888	13,234	13,188
Sum of capital expenditure (excluding financing costs)	39,618	36,083	53,301	75,367	89,179	103,385	86,077	70,198	76,658	59,290
Financing costs	-	-	-	1,515	1,495	89	880	66	86	79
Sum of value of commissioned assets	33,152	32,951	47,349	77,100	106,398	92,013	98,674	69,918	76,791	59,604
Closing works under construction	20,002	23,135	29,086	28,868	13,144	24,605	12,888	13,234	13,188	12,952

We describe how the amounts for capital expenditure, excluding financing costs, are determined in Sections 8 and 9.

We described how the amounts for the sum of commissioned assets and financing costs are determined in Section 7.5.5.

As we discussed in Section 7.5.5, works under construction includes some large projects which span multiple years, but the majority of it is comprised of ongoing capex programmes where the timing is such that some capex was spent in one year but not commissioned (ie: included in the asset register) until the following year. This reflects the lag in our asset completion processes. We note that since we make the simplifying assumption that most of the capex is commissioned in the same year as it is incurred, we do not explicitly model these timing differences on an asset or project basis. As with the value commissioned assets, our assumptions provide reasonable estimates for forecast works under construction.

7.6 Regulatory tax

7.6.1 Regulatory tax allowance

IM 5.4.18 - 5.4.19, 5.3.13 and 5.3.16

The regulatory tax allowance is the difference between BBAR before tax and BBAR after tax, as well as the difference between MAR before and after tax (as stated in Sections 7.2.1 and 7.3.1).

IM requirements

Clauses 5.4.18 and 5.4.19 of the CPP IM require that a CPP proposal must contain:

- the forecast regulatory tax allowance, and particulars of how it was calculated
- other regulated income
- sum of discretionary discounts and customer rebates
- notional deductible interest and the cost of debt assumptions relied upon in its calculation

for each disclosure year after the last disclosure year in which a disclosure has been made pursuant to an ID determination, or for each disclosure year after FY09 where no such disclosure has been made, until the last disclosure year of the next period.

As discussed previously the ID disclosures we have made to date are not consistent with the IMs.

Instead, Orion has made a disclosure for the FY10 disclosure year in response to the 27 August s53ZD Notice issued by the Commission. The information in this disclosure is calculated in accordance with the IMs and includes information relevant to the regulatory tax allowance for FY10.

For the purpose of the CPP proposal we have therefore provided information from FY11 to FY19 which supports our BBAR calculations. Where relevant to the subsequent years, we have also included FY10 values. As noted above, other FY10 data was provided in response to the s53ZD Notice. We note that some of these values are historical, rather than forecast values.

Forecast regulatory tax allowance

Clause 5.3.13 of the CPP IM defines forecast regulatory tax allowance as:

> the maximum of nil and the product of the corporate tax rate and regulatory net taxable income
>
> > *where* regulatory net taxable income means regulatory taxable income less utilised tax losses
> >
> > *where* regulatory taxable income means the sum of regulatory profit/(loss) before tax, permanent differences and regulatory tax adjustments
> >
> > *where* regulatory profit/(loss) before tax means BBAR before tax plus other regulated income less operating expenditure less total depreciation.

The table below shows regulatory tax allowance, and each of the inputs to its calculation stated above.

Regulatory tax allowance ($000 nominal)	**Current Period**		**Assessment Period**	
	FY11	**FY12**	**FY13**	**FY14**
BBAR before tax	142,926	130,926	155,189	186,732
Other regulated income	483	23,453	7,357	(6,945)
Operating expenditure	47,609	54,319	54,640	58,753
Total depreciation	30,817	32,348	33,480	35,886
Regulatory profit/(loss) before tax	64,982	67,713	74,426	85,148
Permanent differences	(55)	(17,273)	(2,926)	6,815
Regulatory tax adjustments	(11,435)	(11,739)	(12,613)	(14,175)
Regulatory taxable income	53,493	38,700	58,887	77,789
Utilised tax losses	-	-	-	-
Regulatory net taxable income	53,493	38,700	58,887	77,789
Corporate tax rate	30%	28%	28%	28%
Forecast regulatory tax allowance	**16,048**	**10,836**	**16,488**	**21,781**

	CPP Period				
	FY15	**FY16**	**FY17**	**FY18**	**FY19**
BBAR before tax	151,819	164,599	169,450	176,095	185,020
Other regulated income	823	840	859	877	896
Operating expenditure	61,205	65,242	64,884	66,419	69,852
Total depreciation	33,535	35,719	37,641	39,756	42,826
Regulatory profit/(loss) before tax	57,902	64,478	67,783	70,797	73,238
Permanent differences	46	47	48	49	50
Regulatory tax adjustments	(7,111)	(8,305)	(9,125)	(9,477)	(9,531)
Regulatory taxable income	50,837	56,220	58,705	61,370	63,757
Utilised tax losses	-	-	-	-	-
Regulatory net taxable income	50,837	56,220	58,705	61,370	63,757
Corporate tax rate	28%	28%	28%	28%	28%
Forecast regulatory tax allowance	**14,234**	**15,742**	**16,437**	**17,183**	**17,852**

Regulatory tax allowance in general matches the profile of BBAR. It reduces in FY12 (as does BBAR) primarily due to unusually high other regulated income, and steps down in FY15 (as does BBAR), primarily due to the lower cost of capital allowance included in BBAR from that year.

The corporate tax rate is defined in Part 1 of the IMs as the rate of income tax applying to companies as specified in the tax rules. The corporate tax rate is currently 28%, having been reduced from 30% in 2011. For Orion, the new tax rate has applied from FY12 onwards. We forecast that it will continue to be 28% until the end of the CPP regulatory period.

We describe how the amounts for the other inputs to regulatory tax allowance are determined in the following sections:

- BBAR before tax (Section 7.3.1)
- other regulated income (Section 7.3.7)
- operating expenditure (Section 7.3.8)
- total depreciation (Section 7.5.3)
- regulatory tax adjustments, utilised tax losses and permanent differences, (respectively, Sections 7.6.1, 7.6.2, and 7.6.3).

Other regulated income

In Section 7.3.7 we set out other regulated income and describe how it is determined. As stated above, other regulated income is an input to the calculation of regulatory tax allowance.

Discretionary discounts and customer rebates

Discretionary discounts and customer rebates are defined in clause 2.3.3(6) of the IMs. They represent discounts from standard prices provided to consumers.

Orion has not provided discretionary discounts and customer rebates over the current period, and we do not expect to do so during the CPP regulatory period.

Regulatory tax adjustments and notional deductible interest

Regulatory tax adjustments

Regulatory tax adjustments are an input to the calculation of BBAR and the regulatory tax allowance.

Clause 5.3.16(1) of the CPP IM defines regulatory tax adjustments as amortisation of initial differences in asset values plus amortisation of revaluations less notional deductible interest.

The table below shows regulatory tax adjustments, and the inputs to its calculation, from FY11 to FY19.

Regulatory tax adjustments ($000 nominal)	Current Period		Assessment Period		CPP Period				
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Amortisation of initial differences in asset values	15,754	15,754	15,754	15,754	15,644	15,670	15,705	15,768	15,768
Amortisation of revaluations	645	1,446	1,893	2,457	2,785	3,619	4,468	5,405	6,530
Notional deductible interest	27,834	28,940	30,260	32,386	25,540	27,594	29,298	30,650	31,829
Regulatory tax adjustments	**(11,435)**	**(11,739)**	**(12,613)**	**(14,175)**	**(7,111)**	**(8,305)**	**(9,125)**	**(9,477)**	**(9,531)**

We describe how the amounts for amortisation of initial differences in asset values are determined in Section 7.6.4, and for amortisation of revaluations in Section 7.6.5.

Notional deductible interest

Notional deductible interest is an input to the calculation of regulatory tax adjustments.

Clause 5.3.16(2) of the IMs defines notional deductible interest as regulatory investment value plus RAB proportionate investment, multiplied by leverage and the cost of debt, plus the term credit spread differential allowance.

The table below shows notional deductible interest, and the inputs to its calculation, from FY11 to FY19.

Notional deductible interest ($000 nominal)	Current Period		Assessment Period		CPP Period				
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Regulatory investment value	788,701	805,728	828,020	882,377	947,866	1,020,126	1,096,137	1,144,264	1,198,366
RAB proportionate investment	16,475	23,675	39,233	45,807	37,614	44,627	34,360	38,395	29,802
Leverage	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44
Cost of debt	7.93%	7.93%	7.93%	7.93%	5.89%	5.89%	5.89%	5.89%	5.89%
Term credit spread differential allowance	-	-	-	-	-	-	-	-	-
Notional deductible interest	**27,834**	**28,940**	**30,260**	**32,386**	**25,540**	**27,594**	**29,298**	**30,650**	**31,829**

We describe how the values for regulatory investment value are determined in Section 7.3.2.

Clause 5.3.23(1) of the CPP IM defines leverage as 44%.

The cost of debt is defined in Part 1 of the IMs as the cost of debt estimated when the Commission estimates vanilla WACC. Unlike for the cost of capital, the CPP IM does not specify which estimate of WACC the cost of debt should relate to. As discussed more fully in Section 7.7.1 however, the CPP IM specifies the WACC estimate which must be used in a CPP proposal with reference to Determinations made by the Commission for that purpose. We take the same approach for the cost of debt. For the CPP regulatory period we use the cost of debt stated in the CPP WACC Determination which applies to this proposal.[26] This is 6.29%. For the claw-back period, we use 7.93%, which is the cost of debt consistent with the WACC we are using in the claw-back period. This is derived from the current DPP WACC.[27]

In Section 7.7.2 we explained why there is no term credit spread differential allowance included in the proposal.

7.6.2 Tax losses

IM 5.4.18, 5.4.20 and 5.3.14

If an EDB makes a regulatory loss (ie a negative profit) in any year, the amount of that loss can be used to offset future regulatory profits to reduce the amount of future regulatory tax allowances. If a loss is made, this generates a balance of tax losses, which when offset against a future profit, is considered utilised.

Annual utilised tax losses are an input to the calculation of both BBAR and the regulatory tax allowance.

IM requirements

Clauses 5.4.18 and 5.4.20 of the IMs require that a CPP proposal must contain:

- amount of opening tax losses (if any), and particulars of how it was calculated
- information describing the nature and amounts of significant items giving rise to any opening tax losses
- information demonstrating that any opening tax losses arose from the supply of electricity distribution services,

for each disclosure year after the last disclosure year in which a disclosure has been made pursuant to an ID determination, or for each disclosure year after FY09 where no such disclosure has been made, until the last disclosure year of the next period.

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[26] Commerce Commission: Cost of capital determination for electricity distribution businesses to apply to a customised price-quality path proposal [2012] NZCC 25, 28 September 2012

[27] Commerce Commission: The Weighted Average Cost of Capital for Services Regulated Under Part 4 of the Commerce Act 1986, Explanatory note to Decision 718, 3 March 2011

Opening tax losses and utilised tax losses

Clause 5.3.14(1) and (5) of the IMs defines opening tax losses as nil in the first disclosure year of the next period, and in subsequent disclosure years as opening tax losses for the preceding disclosure year plus current period tax losses for the preceding disclosure year less utilised tax losses for the preceding disclosure year.

By this definition, there can only be opening tax losses in a given year if there are current period tax losses in previous years.

Clause 5.3.14(6) of the IMs defines current period tax losses as nil if regulatory taxable income is either nil or positive, and as regulatory taxable income if regulatory taxable income is negative.

As stated in Section 7.6.1, we have not recorded and are not projecting negative regulatory taxable income during the claw-back period or CPP regulatory period. Orion also recorded no tax losses in the FY10 period. Therefore, we are not projecting any current period tax losses, or any opening tax losses.

Clause 5.3.14(1 and 2) of the IMs defines utilised tax losses as opening tax losses, subject to the constraint that utilised tax losses may not exceed regulatory taxable income.

Since there are no opening tax losses over this period (see above), there are no utilised tax losses.

7.6.3 Permanent differences

IM 5.4.18, 5.4.21 and 5.3.15

Permanent differences represent the difference between regulatory profit and taxable profit. It includes items which are included in the calculation of one but not in the other. It excludes items which are reversals or will be reversed. These are considered to be temporary differences.

Permanent differences are inputs to the calculation of BBAR and the regulatory tax allowance.

IM requirements

Clauses 5.4.18 and 5.4.21 of the IMs require that a CPP proposal must contain the:

- sum of positive permanent differences
- sum of negative permanent differences
- amounts and nature of items used to determine positive permanent differences and negative permanent differences

for each disclosure year after the last disclosure year in which a disclosure has been made pursuant to an ID determination, or for each disclosure year after FY09 where no such disclosure has been made, until the last disclosure year of the next period.

As discussed in Section 7.6.1, we present information from FY11 to FY19.

We also provide amounts for permanent differences, which are used to determine the amounts for BBAR presented in Section 7.3.1.

Permanent differences

Clause 5.3.15 of the IMs defines permanent differences as positive permanent differences less discretionary discounts and customer rebates less negative permanent differences.

The table below shows permanent differences, and its main components, from FY11 to FY19.

Permanent differences ($000 nominal)	Current Period		Assessment Period		CPP Period				
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Positive pemanent differences	418	5,404	754	6,897	129	132	135	138	141
Discretionary discounts and customer rebates	-	-	-	-	-	-	-	-	-
Negative permanent differences	472	22,678	3,680	81	83	85	87	89	91
Permanent differences	**(55)**	**(17,273)**	**(2,926)**	**6,815**	**46**	**47**	**48**	**49**	**50**

We describe how the amounts for positive permanent differences and negative permanent differences are determined below.

In Section 7.6.1 we stated that Orion does not provide discretionary discounts and customer rebates.

Historical amounts for positive and negative permanent differences

Positive permanent differences are defined in clause 5.3.15(2) of the CPP IM, and negative permanent differences in clause 5.3.15(4) of the CPP IM.

Positive permanent differences are non reversing:

- income items which are treated as taxable under the tax rules but not included as income in determining regulatory profit, or
- expenditure items which are included as expenditure in determining regulatory profit but not deductible under the tax rules.

Negative permanent differences are non reversing:

- income items which are included as income in determining regulatory profit but not treated as taxable under the tax rules, or
- expenditure items which are deductible under the tax rules but not included as expenditure in determining regulatory profit.

We derive forecasts for positive and negative permanent differences based on historical amounts for these items.

The two tables below show the historical amounts for items which comprise positive and negative permanent differences for FY10 to FY12.

Positive permanent differences ($000 nominal)	**Current Period**		
	FY10	**FY11**	**FY12**
Income items			
None	-	-	-
Expenditure items			
Accounting loss on disposal - land	6	-	-
Legal and consultancy fees	28	3	89
Non deductible costs re Opus property offer	-	6	-
ASC binding ruling	71	109	11
ENT expenses	83	75	50
GST on entertainment	9	14	4
Jade Stadium naming rights expensed	210	210	-
Depreciation recovered - contents insurance proceeds	-	-	1,342
Depreciation recovered - Armagh street site	-	-	3,864
Buidling demolition costs	-	-	44
Positive permanent differences	**406**	**418**	**5,404**

Negative permanent differences ($000 nominal)	**Current Period**		
	FY10	**FY11**	**FY12**
Income items			
Tax capital profit on fixed assets sold	1	-	-
Consumer capital contributions	1,666	156	-
Insurance proceeds contents	-	-	2,550
Insurance proceeds Armagh street site	-	-	19,753
Expenditure items			
Tax depreciation on land	20	20	-
Legal & survey re easments capitalised - land	84	82	63
Jade Stadium naming rights deductible for tax	215	215	-
Depreciation recovered on Armagh St not assessable	-	-	312
Negative Permanent differences	**1,986**	**472**	**22,678**

Permanent differences were much larger in FY12 than in the previous two years. This is driven by insurance proceeds (which are included in other regulatory income but are not taxable) and other abnormal items associated with our head office site in that year.

Forecast amounts for positive and negative permanent differences

For some permanent difference items, we have explicitly forecast future values for the purposes of other parts of this proposal. In particular, we have a forecast for insurance proceeds within other regulatory income, and a forecast for building demolition costs in our opex forecast. For these items, we have used the same forecast as used elsewhere.

For all other permanent different items, we base our forecasts on historical difference amounts.

We consider that some of the historical items are likely to recur, and others are unusual, non-recurring items. Items for which a difference was recorded in each year from FY10 to FY12 are considered to be likely to recur throughout the CPP regulatory period. Those which we do not forecast to recur include earthquake related depreciation and insurance proceeds, capital contributions items which are only relevant prior to the FY11 tax change, one-off losses, and Jade Stadium naming rights expenses.

For items which will not recur, we forecast nil amounts. For those which will recur, we forecast that future annual amounts will equal the average amount over the FY10-FY12 period (escalated to FY13$ using CPI).

We then inflate the real forecasts using CPI.

The table below shows our forecast amounts for positive permanent differences, by item. Items which have nil values are those which we do not expect to recur.

Positive permanent differences ($000 nominal)	Current Period	Assessment Period	
		FY13	FY14
Income items			
None		-	-
Expenditure items			
Accounting loss on disposal - land		-	6,648
Legal and consultancy fees		42	43
Non deductible costs re Opus property offer		-	-
ASC binding ruling		72	74
ENT expenses		-	-
GST on entertainment		10	10
Jade Stadium naming rights expensed		-	-
Depreciation recovered - contents insurance proceeds		-	-
Depreciation recovered - Armagh street site		-	-
Buidling demolition costs		630	122
Postive permanent differences		**754**	**6,897**

	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Income items					
None	-	-	-	-	-
Expenditure items					
Accounting loss on disposal - land	-	-	-	-	-
Legal and consultancy fees	44	45	46	47	48
Non deductible costs re Opus property offer	-	-	-	-	-
ASC binding ruling	-	-	-	-	-
ENT expenses	75	77	79	80	82
GST on entertainment	10	10	10	11	11
Jade Stadium naming rights expensed	-	-	-	-	-
Depreciation recovered - contents insurance proceeds	-	-	-	-	-
Depreciation recovered - Armagh street site	-	-	-	-	-
Buidling demolition costs	-	-	-	-	-
Positive permanent differences	**129**	**132**	**135**	**138**	**141**

We forecast that positive permanent differences will be between $0.13m and $0.14m annually during the CPP regulatory period. This is slightly lower than the values in FY10 and FY11, reflecting our assumption that some items in these years were non-recurring.

The table below shows our forecast amounts for negative permanent differences, by item. Items which have nil values are those which we do not expect to recur.

Negative permanent differences ($000 nominal)	Current Period	Assessment Period		CPP Period				
		FY13	FY14	FY15	FY16	FY17	FY18	FY19
Income items								
Tax capital profit on fixed assets sold		-	-	-	-	-	-	-
Consumer capital contributions		-	-	-	-	-	-	-
Insurance proceeds contents		-	-	-	-	-	-	-
Insurance proceeds Armagh street site		3,600	-	-	-	-	-	-
Expenditure items								
Tax depreciation on land		-	-	-	-	-	-	-
Legal & survey re easments capitalised - land		80	81	83	85	87	89	91
Jade Stadium naming rights deductible for tax		-	-	-	-	-	-	-
Depreciation recovered on Armagh St not assessable		-	-	-	-	-	-	-
Negative permanent differences		**3,680**	**81**	**83**	**85**	**87**	**89**	**91**

We forecast that negative permanent differences will be around $0.09m annually during the CPP regulatory period.

We note that there will likely be some permanent difference items in the future that we have not included in our forecast. However, these are very difficult to forecast, and it is unclear whether they would be positive or negative permanent differences. We therefore implicitly assume that any unexpected future items will include both positive and negative items and that these will have a net amount of zero.

7.6.4 Amortisation of initial differences in asset values

IM 5.4.18, 5.4.22 and 5.3.17

At 1 April 2009, there is a difference between the RAB values of assets in the initial RAB and the regulatory tax asset value of those assets. This initial difference is to be amortised over the weighted average remaining life (at 1 April 2009) of the initial assets. The amortisation in each year is part of the regulatory tax adjustments, which are an input to the derivation of BBAR and regulatory tax allowance.

IM requirements

Clauses 5.4.18 and 5.4.22 of the IMs require that a CPP proposal must contain:

- opening unamortised balance of initial differences in asset values, by asset category
- amortisation of initial differences in asset values
- average weighted remaining useful life of the assets relevant to the calculation of the initial regulatory tax asset value,

for each disclosure year after the last disclosure year in which a disclosure has been made pursuant to an ID determination, or for each disclosure year after FY09 where no such disclosure has been made, until the last disclosure year of the next period.

As initial differences are derived from a FY10 value which is based on the values of the assets in the initial RAB, we present the amortisation of initial differences information from FY10 to FY19.

Roll-forward of initial differences in asset values

Definitions

Clause 5.3.17(2) and (3) of the IMs defines opening unamortised initial differences in asset values in FY10 as the initial difference in asset values. That is, they are the difference between the sum of initial RAB values and the sum of regulatory tax asset values at the start of FY10.

Clause 5.3.17(2) and (4) of the IMs defines opening unamortised initial differences in asset values in disclosure years after FY10 as the closing unamortised initial difference in asset values of the preceding disclosure year, adjusted for unamortised initial differences in disposed and acquired assets.

Clause 5.3.17(5) of the IMs defines closing unamortised initial difference in asset values as opening unamortised initial differences in asset values less amortisation of initial differences in asset values.

It is not explicitly clear how the adjustments for disposed and acquired assets should operate. We think that the best interpretation of the above is to adjust closing unamortised initial differences in asset values downwards for the unamortised amount for any assets disposed of in the disclosure year and upwards for the unamortised amount of any assets acquired in the disclosure year. This permits the opening balance (post FY10) to always equal the preceding year's closing balance.

Summary of amortisation of initial differences in asset values roll-forward

The table below shows how closing unamortised initial differences in asset values are derived from the opening balance. It shows the annual amortisation of initial differences in asset values, and the adjustments for the current value of unamortised initial differences in asset values for assets disposed of and acquired, from FY10 to FY19.

Amortisation of initial differences ($000 nominal)	Current Period			Assessment Period		CPP Period				
	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Sum of initial RAB values	774,919									
Sum of opening regulatory tax asset values	247,461									
Initial differences in asset values	527,459									
Opening unamortised initial differences in asset values	527,459	511,704	495,950	480,195	464,441	444,555	429,524	414,653	399,748	383,979
Amortisation of initial differences in asset values	15,754	15,754	15,754	15,754	15,754	15,644	15,670	15,705	15,768	15,768
Unamortised initial differences in asset values of acquired assets	-	-	-	-	631	612	799	799	-	-
Unamortised initial differences in asset values of disposed assets	-	-	-	-	4,762	-	-	-	-	-
Closing unamortised initial differences in asset values	511,704	495,950	480,195	464,441	444,555	429,524	414,653	399,748	383,979	368,211

Regarding the initial difference in asset values, we described how the amounts for the sum of initial RAB values and for the sum of regulatory tax asset values are determined in Sections 7.5.2 and 7.6.8.

We show below, how the amounts for amortisation of initial differences in asset values are determined, as well as the unamortised balance for acquired or disposed assets.

Initial differences in asset values by asset category

As stated above, the IMs require a CPP proposal to provide opening unamortised balances of initial differences by asset categories. This is difficult to calculate. Initial differences in asset values are determined as the difference between the sum of the RAB values and the regulatory tax asset values of the assets in the initial RAB. It is not built up from initial differences of individual assets.

Disaggregating the value is made more difficult by the fact that our asset categories differ between the RAB and tax asset registers. The following table provides the asset values by network and non-network asset categories.

Opening unamortised balance of the initial differences in asset values ($000 nominal)	Current Period			Assessment Period	
	FY10	FY11	FY12	FY13	FY14
Network assets	520,632	505,081	489,531	473,980	458,429
Non-network assets	6,827	6,623	6,419	6,215	6,011

	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Network assets	443,510	428,544	413,739	398,900	383,197
Non-network assets	1,045	979	914	848	782

The tables in the next sub-section show the initial differences for assets in the initial RAB, acquired assets and disposed assets.

Amortisation of initial differences in asset values

Clause 5.3.17(1) of the CPP IM defines amortisation of initial differences in asset values as the opening unamortised initial difference in asset values divided by the weighted average remaining useful life of relevant assets. Clause 5.3.17(4) of the CPP IM states that annual amortisation should not include that relating to disposed assets after any sale, and that it should include amortisation relating to acquired assets after any acquisition.

We determine the amortisation value for each year from FY10 to FY19 for assets in our initial RAB, and then adjust it to take account of acquired and disposed assets. For acquired assets, we determine the initial difference for the assets we will acquire, and the annual amortisation. Once a set of assets is acquired, we add the annual amortisation value to our value for assets in the initial RAB. For disposed assets, we deduct the annual amortisation related to the asset after the disposal.

The tables below show:

- the opening unamortised initial differences in asset values
- the weighted average remaining life of the assets
- the amortisation of initial differences in asset values,

separately for assets in the initial RAB, acquired assets, and assets to be disposed of, from FY10 to FY19.

We have not included data pertaining to assets acquired from Transpower in FY13. For these assets, we have adopted a RAB value and a regulatory tax asset value which are the same as at 1 April 2009. There are therefore no initial differences associated with the assets acquired in FY13.

Amortisation of initial differences - assets in initial RAB ($000 nominal)	Current Period			Assessment Period		CPP Period				
	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Opening unamortised initial differences in asset values	527,459	511,704	495,950	480,195	464,441	448,686	432,932	417,177	401,423	385,668
Weighted average remaining life of relevant assets	33.5	32.5	31.5	30.5	29.5	28.5	27.5	26.5	25.5	24.5
Amortisation of initial differences in asset values	15,754	15,754	15,754	15,754	15,754	15,754	15,754	15,754	15,754	15,754

Amortisation of initial differences - FY14 acquired assets ($000)	Current Period			Assessment Period		CPP Period				
	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Opening unamortised initial differences in asset values	-	-	-	-	-	631	604	576	549	521
Weighted average remaining life of relevant assets	-	-	-	-	22.9	21.9	20.9	19.9	18.9	17.9
Amortisation of initial differences in asset values	-	-	-	-	-	28	28	28	28	28

Amortisation of initial differences - FY15 acquired assets ($000)	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Opening unamortised initial differences in asset values	-	612	586	561	535
Weighted average remaining life of relevant assets	23.7	22.7	21.7	20.7	19.7
Amortisation of initial differences in asset values	-	26	26	26	26

Amortisation of initial differences - FY16 acquired assets ($000)	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Opening unamortised initial differences in asset values	-	-	799	764	729
Weighted average remaining life of relevant assets	-	22.7	21.7	20.7	19.7
Amortisation of initial differences in asset values	-	-	35	35	35

Amortisation of initial differences - FY17 acquired assets ($000)	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Opening unamortised initial differences in asset values	-	-	-	799	736
Weighted average remaining life of relevant assets	-	-	12.6	11.6	10.6
Amortisation of initial differences in asset values	-	-	-	63	63

Amortisation of initial differences - Disposed assets after disposal ($000 nominal)	Current Period			Assessment Period		CPP Period				
	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Opening unamortised initial differences in asset values	-	-	-	-	4,901	4,901	4,762	4,624	4,486	4,348
Weighted average remaining life of relevant assets	-	-	-	-	35.5	34.5	33.5	32.5	31.5	30.5
Amortisation of initial differences in asset values	-	-	-	-	-	138	138	138	138	138

The table below shows amortisation of initial differences in asset values, in total and separately for assets in the initial RAB, disposed assets and acquired assets, for each disclosure year from FY10 to FY19.

Amortisation of initial differences in asset values ($000)	Current Period			Assessment Period		CPP Period				
	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Assets in initial RAB	15,754	15,754	15,754	15,754	15,754	15,754	15,754	15,754	15,754	15,754
plus Acquired assets	-	-	-	-	-	28	53	89	152	152
less Disposed assets	-	-	-	-	-	138	138	138	138	138
Amortisation of initial differences	**15,754**	**15,754**	**15,754**	**15,754**	**15,754**	**15,644**	**15,670**	**15,705**	**15,768**	**15,768**

Weighted average remaining useful life of relevant assets

Each of the assets in the initial RAB has a remaining life. We use this remaining life value to depreciate the assets. This process and remaining life information are set out in Section 7.5.3.

To derive the weighted average remaining useful life of relevant assets, for the purpose of amortising initial differences in asset values, we calculate the average remaining life of the assets in the initial RAB, weighted by the initial RAB value of each asset.

Using this method, we derive a weighted average remaining useful life of relevant assets of 33.5 years.

Since initial differences are amortised as a group, this remaining life is reduced by 1 each year.

When assets are acquired which have unamortised initial differences, we derive the remaining life of acquired assets based on what it would have been if the acquired assets had been in the initial RAB. This is explained in more detail below. We treat disposals similarly.

The weighted average remaining life for each type of asset is set out in the tables above.

Further calculations for disposed and acquired assets

Acquired assets

When we add assets acquired from another regulated supplier to the RAB, we also add any unamortised balances of initial differences in asset values to our unamortised balance. We have estimated the initial differences for each acquisition, as it is not possible for Transpower to provide us with opening FY10 asset values for the relevant assets.[28]

We split each acquisition into its component assets. For each asset, we estimate the RAB and tax asset values at 1 April 2009 by reverse depreciating the RAB and tax data we have, as at each acquisition date. This allows us to derive the initial difference for each acquisition.

Using a weighted average of the remaining lives which we derive from the RAB depreciation calculations, we derive the annual amortisation of initial differences for each acquisition. We calculate the cumulative amortisation from the start of FY10 until the acquisition date, as if the IMs had applied to those assets from that date. The unamortised amount is that which we add to our balance of unamortised initial differences upon acquisition.

The tables above show our estimate of the unamortised balance of initial differences on the acquisition date for each year's acquisition. Following acquisition, we amortise the value using the remaining weighted average life, which is reduced by 1 each year until the balance is fully amortised.

Disposed assets

In Section 7.5.6 we set out the impact of our RAB of disposing of the assets associated with our Armagh Street head office site. In addition to reducing the total RAB value, where a disposal has unamortised initial differences, these must be removed from the balance, so that future amortisations do not include initial differences for the disposed assets.

While the initial differences of assets in the initial RAB are treated as a group (and amortised together with one weighted average life), in order to determine how much to reduce the unamortised balance by, we need to derive the amortisation of initial differences for the disposed assets. We calculate the initial differences for the disposed assets, and calculate the annual amortisation (using the same weighted average remaining life as we use for all initial differences). From this we can derive the unamortised balance associated with the disposed assets at the disposal date.

This is the amount we remove from the unamortised balance of initial differences, as shown in the table above relating to disposed assets.

Tax effect of amortisation of initial differences in asset values

The "tax effect" of amortisation of initial differences in asset values is an input to the calculation of deferred tax, as discussed in Section 7.6.6.

The tax effect of an item is defined in Part 1 of the IMs as the amount of the item multiplied by the corporate tax rate. We stated the amounts for the corporate tax rate above.

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[28] We note that Transpower is subject to a different set of IMs, and has a different regulatory period to Orion. Accordingly Transpower does not prepare RAB and regulatory tax information on the same basis as that we require for the CPP proposal.

The table below shows amortisation of initial differences in asset values, the corporate tax rate, and the tax effect of amortisation of initial differences in asset values, from FY10 to FY19.

Tax effect of amortisation of initial differences in asset values ($000 nominal)	Current Period			Assessment Period	
	FY10	FY11	FY12	FY13	FY14
Amortisation of initial differences in asset values	15,754	15,754	15,754	15,754	15,754
Corporate tax rate	30%	30%	28%	28%	28%
Tax effect of amortisation of initial differences	**4,726**	**4,726**	**4,411**	**4,411**	**4,411**

	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Amortisation of initial differences in asset values	15,644	15,670	15,705	15,768	15,768
Corporate tax rate	28%	28%	28%	28%	28%
Tax effect of amortisation of initial differences	**4,380**	**4,388**	**4,397**	**4,415**	**4,415**

7.6.5 Amortisation of revaluations

IM 5.4.18, 5.4.23 and 5.3.18

We discussed in Section 7.5.4 how assets in the RAB are revalued annually using CPI. This means that depreciation on an individual asset (under the standard method) increases over time, despite the use of the “straight line” approach. However, to calculate tax depreciation to determine taxable profit, regulatory tax asset values are not revalued in a similar fashion.

Therefore a difference arises between RAB depreciation and regulatory tax deprecation for each asset, which is created because of the RAB revaluations.

The forecast tax allowance is adjusted to account for this difference. This adjustment is termed amortisation of revaluations. It also affects BBAR through the regulatory tax adjustments.

IM requirements

Clauses 5.4.18 and 5.4.23 of the IMs require that a CPP proposal must contain:

- unamortised balance of revaluations to date
- adjusted depreciation
- average weighted remaining useful life of the assets used to determine the amortisation of revaluations
- particulars of how the average weighted remaining useful life was calculated,

for each disclosure year after the last disclosure year in which a disclosure has been made pursuant to an ID determination, or for each disclosure year after FY09 where no such disclosure has been made, until the last disclosure year of the next period.

As discussed in Section 7.6.1, we present information from FY11 to FY19.

Amortisation of revaluations, total depreciation and adjusted depreciation

Clause 5.3.18 of the IMs defines amortisation of revaluations as total depreciation less adjusted depreciation.

The table below shows total depreciation, adjusted depreciation, and amortisation of revaluations, from FY11 to FY19.

Amortisation of revaluations ($000 nominal)	Current Period		Assessment Period		CPP Period				
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Total depreciation	30,817	32,348	33,480	35,886	33,535	35,719	37,641	39,756	42,826
Adjusted depreciation	30,173	30,902	31,587	33,429	30,750	32,100	33,173	34,351	36,296
Amortisation of revaluations	**645**	**1,446**	**1,893**	**2,457**	**2,785**	**3,619**	**4,468**	**5,405**	**6,530**

In Section 7.5.3 we described how the amounts for total depreciation and adjusted depreciation are determined.

Other items required by clause 5.4.23 of the IMs

We do not provide any amounts for the unamortised balance of revaluations to date or the average weighted remaining useful life of the assets used to determine the amortisation of revaluations. Nor do we provide particulars as to how the average weighted remaining useful life was calculated.

These items are not relevant to the calculation of annual amortisation of revaluations, and accordingly they do not exist. These items are not part of the definition of amortisation of revaluations, specified in clause 5.3.18 of the IMs, nor are they calculated in any other part of the calculation of BBAR.

As stated above, clause 5.3.18 of the IMs defines amortisation of revaluations as the difference between total depreciation and adjusted depreciation in a given disclosure year. There is no balance to be amortised. Likewise, there is no group of assets used to determine the amortisation, and hence no weighted average remaining life. The calculation doesn’t require these items.

7.6.6 Deferred tax

IM 5.4.18, 5.4.24 and 5.3.19

Deferred tax represents the tax on earnings which accumulate tax-free until some future date. It is tax payable which is stored up to be paid in future years.

Deferred tax affects BBAR in two ways:

- it is part of the regulatory investment value as either a positive amount (representing a deferred tax asset) or a negative amount (a deferred tax liability)
- it is part of a timing adjustment to reflect the assumption that tax is paid (on average) on a different day within the year to when revenue is collected.

IM requirements

Clauses 5.4.18 and 5.4.24 of the IMs require that a CPP proposal must contain:

- opening deferred tax
- analysis of temporary differences and other adjustments by nature that give rise to opening deferred tax value
- closing deferred tax
- reconciliation of opening deferred tax to closing deferred tax by nature of temporary differences and other adjustments,

for each disclosure year after the last disclosure year in which a disclosure has been made pursuant to an ID determination, or for each disclosure year after FY09 where no such disclosure has been made, until the last disclosure year of the next period.

As discussed in Section 7.6.1, we present information from FY11 to FY19.

Opening deferred tax, closing deferred tax, and adjustments that give rise to deferred tax

Clause 5.3.19(1) of the IMs defines opening deferred tax as nil in FY10 and as closing deferred tax from the preceding disclosure year for all disclosure years after FY10.

Clause 5.3.19(2) of the IMs defines closing deferred tax as opening deferred tax plus the tax effect of temporary differences, less the tax effect of amortisation of initial differences in asset values, plus deferred tax balance of assets acquired in the disclosure year, plus cost allocation adjustment.

The table below shows how closing deferred tax is derived from opening deferred tax, from FY11 to FY19. It includes the tax effect of temporary differences, tax effect of amortisation of initial differences in asset values, deferred tax balance of assets acquired in the disclosure year.

In Section 7.4.2 we described how we have no assets which are not directly attributable. Therefore, neither the closing RAB values nor the regulatory tax asset values at the end of the year change as a result of applying the cost allocation methodology. The cost allocation adjustment, as defined in clause 5.3.19(5) of the CPP IMs, is therefore not relevant to our deferred tax calculation.

Deferred tax ($000 nominal)	Current Period		Assessment Period	
	FY11	FY12	FY13	FY14
Opening deferred tax	(6,210)	(10,529)	(16,065)	(20,535)
Tax effect of temporary differences	407	(1,124)	(98)	(501)
Tax effect of amortisation of initial differences in asset values	4,726	4,411	4,411	4,411
Deferred tax balance of assets acquired in the disclosure year	-	-	39	(124)
Closing deferred tax	(10,529)	(16,065)	(20,535)	(25,571)

	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Opening deferred tax	(25,571)	(34,332)	(44,032)	(52,799)	(61,578)
Tax effect of temporary differences	(3,141)	(4,349)	(4,444)	(4,364)	(4,497)
Tax effect of amortisation of initial differences in asset values	4,380	4,388	4,397	4,415	4,415
Deferred tax balance of assets acquired in the disclosure year	(1,240)	(964)	74	-	-
Closing deferred tax	(34,332)	(44,032)	(52,799)	(61,578)	(70,490)

We are forecasting to build up a negative deferred tax balance (liability) of $70m by the end of the CPP regulatory period.

We describe how the amounts for amortisation of initial differences in asset values and temporary differences are determined in Sections 7.6.4 and 7.6.7.

Deferred tax of acquired assets

We outlined in Section 7.6.4 how assets acquired from Transpower may have an unamortised balance of initial differences, which we have to add to our balance upon acquisition. These assets may also have a deferred tax balance, after applying the regulatory tax method to them, as set out in the IMs.

The deferred tax balance for acquired assets is made up of two components. The first is the tax effect of amortised initial differences prior to acquisition, and the second the tax effect of the depreciation temporary differences (the difference between adjusted depreciation and tax depreciation) prior to acquisition.

We calculate the former in order to derive the unamortised balance of initial differences, as set out above.

For depreciation temporary differences, we estimate the amount of regulatory and tax depreciation incurred for each asset between the start of FY10 and the acquisition date, in order to estimate initial differences. Since Transpower's regulatory depreciation does not include revaluations, the difference between regulatory and tax depreciation is also the depreciation temporary difference. We calculate the tax effect of this difference.

Combining these two items gives us our estimate of the deferred tax balance for each set of acquired assets.

7.6.7 Temporary differences

IM 5.4.18, 5.4.25 and 5.3.20

Temporary differences represent all the items which are included in the calculation of either regulatory profit or taxable profit but not in the other, which are reversals or will be reversed. Those items which are not reversals, or will not reverse are considered permanent differences.

The tax effect of temporary differences is an input to the calculation of deferred tax.

IM requirements

Clauses 5.4.18 and 5.4.25 of the IMs require that a CPP proposal must contain:

- a description of the methodology and depreciation rates by asset category used to determine the forecast tax depreciation
- amounts and nature of other forecast temporary differences
- particulars of the calculation of the tax effect of temporary differences showing tax rates used

for each disclosure year after the last disclosure year in which a disclosure has been made pursuant to an ID determination, or for each disclosure year after FY09 where no such disclosure has been made, until the last disclosure year of the next period.

As discussed in Section 7.6.1, we present information from FY11 to FY19.

We also provide amounts for the tax effect of temporary differences, which are used to determine the amounts for deferred tax presented in Section 7.6.6.

Tax effect of temporary differences

The tax effect of an item is defined in Part 1 of the IMs as the amount of the item multiplied by the corporate tax rate.

The table below shows temporary differences, the corporate tax rate, and the tax effect of temporary differences, for each disclosure year from FY11 to FY19.

Tax effect of temporary differences ($000 nominal)	Current Period		Assessment Period		CPP Period				
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Temporary differences	1,356	(4,016)	(351)	(1,789)	(11,217)	(15,531)	(15,872)	(15,586)	(16,061)
Corporate tax rate	30%	28%	28%	28%	28%	28%	28%	28%	28%
Tax effect of temporary differences	**407**	**(1,124)**	**(98)**	**(501)**	**(3,141)**	**(4,349)**	**(4,444)**	**(4,364)**	**(4,497)**

We explain how the amounts for temporary differences are determined below. We explained how the amounts for the corporate tax rate are determined in Section 7.3.1.

Temporary differences

Clause 5.3.20(1) of the IMs defines temporary differences as depreciation temporary differences plus positive temporary differences less negative temporary differences. The table below shows temporary differences and its components, from FY11 to FY19.

Temporary differences ($000 nominal)	Current Period		Assessment Period		CPP Period				
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Depreciation temporary differences	1,212	2,813	4,206	2,534	(5,410)	(7,403)	(9,222)	(8,762)	(9,072)
Positive temporary differences	8,682	4,788	5,062	5,938	4,937	5,044	5,153	5,265	5,379
Negative temporary differences	8,538	11,617	9,619	10,261	10,744	13,171	11,803	12,090	12,368
Temporary differences	**1,356**	**(4,016)**	**(351)**	**(1,789)**	**(11,217)**	**(15,531)**	**(15,872)**	**(15,586)**	**(16,061)**

We explain how the amounts for each component are determined below.

Depreciation temporary differences

Clause 5.3.20(2) of the IMs defines depreciation temporary differences as adjusted depreciation less tax depreciation.

The table below shows adjusted depreciation, tax depreciation, and depreciation temporary differences, for each disclosure year from FY11 to FY19.

Depreciation temporary differences ($000 nominal)	Current Period		Assessment Period		CPP Period				
	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Adjusted depreciation	30,173	30,902	31,587	33,429	30,750	32,100	33,173	34,351	36,296
Tax depreciation	28,961	28,089	27,381	30,895	36,160	39,503	42,395	43,113	45,368
Depreciation temporary differences	**1,212**	**2,813**	**4,206**	**2,534**	**(5,410)**	**(7,403)**	**(9,222)**	**(8,762)**	**(9,072)**

We describe how we determine the amounts for adjusted depreciation in Section 7.5.3 and for tax depreciation in Section 7.6.8.

Historical amounts for positive and negative temporary differences

Positive temporary differences are defined in clause 5.3.20(4) of the IMs. Negative temporary differences are defined in clause 5.3.20(5) of the IMs. They are the same as permanent differences, but only include items which are reversals or will be reversed.

We derive forecasts for positive and negative temporary differences based on historical amounts for these items.

The tables below show the historical amounts for items which comprise positive and negative temporary differences for FY10 to FY12.

They show a range of differences, with year on year variances in the amounts and causes. These amounts are significantly higher than the corresponding values for permanent differences.

Positive temporary differences ($000 nominal)	Current Period		
	FY10	FY11	FY12
Income items			
Tax profit on sale (excluding buildings)	81	56	205
Expenditure items			
Accounting profits on sale	-	-	100
Cable assets destroyed	-	3,334	-
Building substations destroyed	-	-	394
Disposal of item not in tax register	0	0	-
Software & hardware expensed	32	-	-
Replacement tools expensed	7	-	-
Network maintenance capital for tax	-	163	-
Property maintenance capital for tax	-	22	-
Earthquake related capex in tax	-	99	-
Finance lease accounting interest	72	71	65
Holiday pay accrual	1,711	1,914	1,654
Long service leave accrual	575	635	734
Doubtful debts provision	287	97	167
General provisions	81	97	108
Provision for stock write down	231	-	-
Earthquake related cost adjustment 2011	-	4	-
Earthquake related cost adjustment 2012	-	-	11
Software / hardware maintenance adjustment	-	-	1
ACC accrual liability	131	135	120
Property costs to capital	-	-	11
Network maintenance capitalised	-	13	-
Earthquake related capex	-	18	-
Loss on Moffet St not deductible	45	-	-
Recovery for diesel from retailers income	-	-	244
Unexpired portion of Gen I firewall licence	3	-	-
Gen I firewall licence to claim in 2012/2013	-	2	-
Survey costs to be capitalised in P1/2013	-	-	3
Network WIP capital for accounting claimed for tax	-	1,832	635
Unexpired expenditure accrual	251	189	336
Positive temporary differences	**3,508**	**8,682**	**4,788**

Negative temporary differences ($000 nominal)	Current Period		
	FY10	FY11	FY12
Income items			
Accounting profits on sale (capital & revenue)	35	21	-
Internal profits total	928	1,342	250
Expenditure items			
Disposal of item in tax not accounting	-	-	0
Network capitalised for accounting claimed for tax	3,450	2,846	1,502
Depreciation recovered on Armagh street site insurance	-	-	3,552
Depreciation recovered on contents insurance	-	-	1,342
Claim lease payments on operating leases	103	105	103
Holiday pay accrual	1,729	1,711	1,914
Long service leave accrual	648	575	635
Doubtful Debts Provision	95	287	97
General Provisions	167	81	97
Provision for stock write down 2009	201	-	-
Provision for stock write down 2010	-	231	-
2011 earthquake related cost adjustment	-	15	-
Maintenance adjustments 2011	-	1	-
ACC accrual liability	161	131	135
Hanmer smoke alarms capitalised	2	-	-
Property costs to capital	-	11	-
Network maintenance capitalised	-	-	13
Earthquake related capex	-	-	18
NAV project costs in 2009 capitalised in 2010	66	-	-
Recovery for diesel from retailers income in 2012	-	244	-
Loss on Moffet St not deductible in 2011	-	45	-
Gen I firewall licence added back in 2011	-	3	-
Gen I firewall licence to claim in 2012/2013	-	-	2
Network WIP capitalised for accounting claimed for tax	1,832	635	1,768
Unexpired expenditure accrual	255	251	189
Negative temporary differences	**9,672**	**8,538**	**11,617**

Forecast amounts for positive and negative temporary differences

For some temporary difference items, we have explicitly forecast future values for the purposes of other parts of this proposal. In particular, we have a forecast for profit and loss on the sale of the Armagh St assets and vehicles which have reached the end of their useful lives. For these items, we have used the same forecasts as used elsewhere.

For all other temporary differences, we base our forecast amounts on historical difference amounts. We use the same method as for permanent differences, which we discuss in Section 7.6.3.

We consider that some of the historical items are likely to recur, and others are unusual, non-recurring items. Those items for which we do not forecast recurring differences include earthquake related asset disposals, one-off purchases, and other items where a difference was recorded in only one of FY10 to FY12. Items for which a difference was recorded in each year from FY10 to FY12 are considered to be likely to recur throughout the CPP regulatory period.

For items which will not recur, we forecast nil amounts. For those which will recur indefinitely, we forecast that future annual amounts will equal (in real terms) the average amount over the FY10 to FY12 period (escalated to FY13 terms using CPI). Some of the temporary differences are both positive and negative, with each value reversing in the subsequent year. For these items we calculate the historical average jointly, ensuring that the forecast for each of the positive and negative items are internally consistent.

We then inflate the real forecasts using CPI.

The table below shows our forecast amounts for positive temporary differences.

We note that there will likely be some temporary difference items in the future that we have not attempted to forecast, given they are difficult to forecast, and it is unclear whether they would be positive or negative temporary differences. We implicitly assume that any unexpected future difference items will include both positive and negative items and that these will have a net amount of zero.

Positive temporary differences ($000 nominal)	Current Period	Assessment Period	
		FY13	FY14
Income items			
Tax profit on sale (excluding buildings)		-	-
Expenditure items		-	-
Accounting profits on sale		-	1,102
Cable assets destroyed		-	-
Building substations destroyed		-	-
Disposal of item not in tax register		-	-
Software & hardware expensed		-	-
Replacement tools expensed		-	-
Network maintenance capital for tax		-	-
Property maintenance capital for tax		-	-
Earthquake related capex in tax		-	-
Finance lease accounting interest		73	74
Holiday pay accrual		1,844	1,879
Long service leave accrual		679	692
Doubtful debts provision		193	196
General provisions		100	102
Provision for stock write down		-	-
Earthquake related cost adjustment 2011		-	-
Earthquake related cost adjustment 2012		-	-
Software / hardware maintenance adjustment		-	-
ACC accrual liability		135	137
Property costs to capital		-	-
Network maintenance capitalised		-	-
Earthquake related capex		-	-
Loss on Moffet St not deductible		-	-
Recovery for diesel from retailers income		-	-
Unexpired portion of Gen I firewall licence		-	-
Gen I firewall licence to claim in 2012/2013		-	-
Survey costs to be capitalised in P1/2013		-	-
Network WIP capital for accounting claimed for tax		1,768	1,479
Unexpired expenditure accrual		271	276
Postive temporary differences		**5,062**	**5,938**

	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Income items					
Tax profit on sale (excluding buildings)	-	-	-	-	-
Expenditure items					
Accounting profits on sale	-	-	-	-	-
Cable assets destroyed	-	-	-	-	-
Building substations destroyed	-	-	-	-	-
Disposal of item not in tax register	-	-	-	-	-
Software & hardware expensed	-	-	-	-	-
Replacement tools expensed	-	-	-	-	-
Network maintenance capital for tax	-	-	-	-	-
Property maintenance capital for tax	-	-	-	-	-
Earthquake related capex in tax	-	-	-	-	-

	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Finance lease accounting interest	76	77	79	81	82
Holiday pay accrual	1,920	1,961	2,004	2,047	2,091
Long service leave accrual	707	722	738	754	770
Doubtful debts provision	200	205	209	214	218
General provisions	104	106	109	111	114
Provision for stock write down	-	-	-	-	-
Earthquake related cost adjustment 2011	-	-	-	-	-
Earthquake related cost adjustment 2012	-	-	-	-	-
Software / hardware maintenance adjustment	-	-	-	-	-
ACC accrual liability	140	143	147	150	153
Property costs to capital	-	-	-	-	-
Network maintenance capitalised	-	-	-	-	-
Earthquake related capex	-	-	-	-	-
Loss on Moffet St not deductible	-	-	-	-	-
Recovery for diesel from retailers income	-	-	-	-	-
Unexpired portion of Gen I firewall licence	-	-	-	-	-
Gen I firewall licence to claim in 2012/2013	-	-	-	-	-
Survey costs to be capitalised in P1/2013	-	-	-	-	-
Network WIP capital for accounting claimed for tax	1,507	1,540	1,573	1,607	1,642
Unexpired expenditure accrual	282	289	295	301	308
Positive temporary differences	**4,937**	**5,044**	**5,153**	**5,265**	**5,379**

The table below shows our forecast amounts for negative temporary differences.

Negative temporary differences ($000 nominal)	Current Period	Assessment Period	
		FY13	FY14
Income items			
Accounting profits on sale (capital & revenue)		300	306
Internal profits total		880	897
Expenditure items			
Disposal of item in tax not accounting		-	-
Network capitalised for accounting claimed for tax		3,732	4,219
Depreciation recovered on Armagh street site insurance		-	-
Depreciation recovered on contents insurance		-	-
Claim lease payments on operating leases		108	111
Holiday pay accrual		1,654	1,844
Long service leave accrual		734	679
Doubtful Debts Provision		167	193
General Provisions		108	100
Provision for stock write down 2009		-	-
Provision for stock write down 2010		-	-
2011 earthquake related cost adjustment		-	-
Maintenance adjustments 2011		-	-

Negative temporary differences ($000 nominal)	Current Period	Assessment Period	
		FY13	FY14
ACC accrual liability		120	135
Hanmer smoke alarms capitalised		-	-
Property costs to capital		-	-
Network maintenance capitalised		-	-
Earthquake related capex		-	-
NAV project costs in 2009 capitalised in 2010		-	-
Recovery for diesel from retailers income in 2012		-	-
Loss on Moffet St not deductible in 2011		-	-
Gen I firewall licence added back in 2011		-	-
Gen I firewall licence to claim in 2012/2013		-	-
Network WIP capitalised for accounting claimed for tax		1,479	1,507
Unexpired expenditure accrual		336	271
Negative temporary differences		**9,619**	**10,261**

	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Income items					
Accounting profits on sale (capital & revenue)	312	319	326	333	340
Internal profits total	917	936	957	977	999
Expenditure items	-	-	-	-	-
Disposal of item in tax not accounting	-	-	-	-	-
Network capitalised for accounting claimed for tax	4,579	6,873	5,369	5,515	5,651
Depreciation recovered on Armagh street site insurance	-	-	-	-	-
Depreciation recovered on contents insurance	-	-	-	-	-
Claim lease payments on operating leases	113	115	118	120	123
Holiday pay accrual	1,879	1,920	1,961	2,004	2,047
Long service leave accrual	692	707	722	738	754
Doubtful Debts Provision	196	200	205	209	214
General Provisions	102	104	106	109	111
Provision for stock write down 2009	-	-	-	-	-
Provision for stock write down 2010	-	-	-	-	-
2011 earthquake related cost adjustment	-	-	-	-	-
Maintenance adjustments 2011	-	-	-	-	-
ACC accrual liability	137	140	143	147	150
Hanmer smoke alarms capitalised	-	-	-	-	-
Property costs to capital	-	-	-	-	-
Network maintenance capitalised	-	-	-	-	-
Earthquake related capex	-	-	-	-	-
NAV project costs in 2009 capitalised in 2010	-	-	-	-	-
Recovery for diesel from retailers income in 2012	-	-	-	-	-
Loss on Moffet St not deductible in 2011	-	-	-	-	-
Gen I firewall licence added back in 2011	-	-	-	-	-

	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Gen I firewall licence to claim in 2012/2013	-	-	-	-	-
Network WIP capitalised for accounting claimed for tax	1,540	1,573	1,607	1,642	1,678
Unexpired expenditure accrual	276	282	289	295	301
Negative temporary differences	**10,744**	**13,171**	**11,803**	**12,090**	**12,368**

7.6.8 Regulatory tax asset values

IM 5.4.18, 5.4.26 and 5.3.21

The primary purpose of the regulatory tax asset values is to determine tax depreciation, for the purpose of determining taxable profit. In a regulatory context, tax depreciation is an input to the derivation of depreciation temporary differences, which (as part of temporary differences) is an input to the derivation of the regulatory tax allowance.

We note that the set of assets which have RAB values at a given point in time may differ from the set of assets which have regulatory tax asset values at that time. This is because:

- some expenditure items are capitalised for regulatory purposes but expensed for tax purposes (or vice versa)
- depreciation methods differ between the RAB and tax assets, thus assets will typically become fully depreciated under one method before the other.

IM requirements

Clauses 5.4.18 and 5.4.26 of the IMs require that a CPP proposal must contain:

- sum of tax asset values at the start of the disclosure year
- sum of tax asset values by asset category at the start of the disclosure year
- sum of regulatory tax asset values at the start of the disclosure year
- sum of regulatory tax asset values by asset category at the start of the disclosure year
- weighted average remaining tax life of assets and tax depreciation methodology employed, by asset category
- particulars of the calculation used to derive the regulatory tax asset values at the start of the disclosure year from the tax asset values at the start of the disclosure year
- sum of regulatory tax asset values at the end of the disclosure year
- reconciliation between the sum of regulatory tax asset values at the start of the disclosure year and the sum of regulatory tax asset values at the end of the disclosure year, by asset category, showing the values of capital additions, disposals, tax depreciation and other asset adjustments including cost allocation adjustments,

for each disclosure year after the last disclosure year in which a disclosure has been made pursuant to an ID determination, or for each disclosure year after 2009 where no such disclosure has been made, until the last disclosure year of the next period.

As discussed in Section 7.6.1, we present information from FY10 to FY19.

Tax asset values at the start of the year

The tax asset value of an asset is defined in clause 5.3.21(2) of the CPP IM. It is the asset value, as determined using the tax rules.

The table below shows the sum of tax asset values by asset category, and in total. We note that the categories for assets commissioned prior to FY13 (ie: actual assets) differ from the categories for assets commissioned from FY13 (ie: forecast assets) and those used to present RAB values. This is the result of the disjoint between the categories used to disaggregate historical tax asset records, and the way in which we collect our capex data for forecast periods.

Opening tax asset values ($000 nominal)	Current Period			Assessment Period	
	FY10	FY11	FY12	FY13	FY14
Distribution	218,722	218,432	218,166	232,566	262,394
System buildings	23,088	25,193	26,307	25,641	34,379
System land	6,859	7,236	7,493	8,239	8,904
Non system fixed assets	15,071	15,693	14,057	16,222	19,131
Acquired assets	-	-	-	-	4,329
Adjustments to the tax register	(16,279)	(16,452)	(15,704)	(21,363)	(22,586)
Total	**247,461**	**250,102**	**250,318**	**261,304**	**306,552**

	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Distribution	307,460	333,677	373,964	392,340	410,935
System buildings	42,218	52,970	61,474	69,205	80,684
System land	8,884	9,691	10,240	10,338	10,745
Non system fixed assets	31,010	29,275	27,783	26,147	25,732
Acquired assets	5,692	17,062	21,183	20,458	19,069
Adjustments to the tax register	(21,682)	(23,750)	(28,563)	(31,681)	(33,173)
Total	**373,583**	**418,926**	**466,081**	**486,808**	**513,993**

For commissioned assets, there is a particular set of assets for which we assume that 80% of the value is expensed for tax purposes, while 100% is added to the RAB. These assets are overhead lines (all voltages), and 11kV and LV XLPE underground cables. This is consistent with the tax treatment for our existing assets of these types.

Regulatory tax asset values at the start of the year

Clause 5.3.21(1) of the IMs defines the regulatory tax asset value of an asset as the tax asset value multiplied by the result of asset allocation ratio.

As outlined in Section 7.4.2, all of our assets are directly attributed. The result of the asset allocation ratio is therefore 1. This means that regulatory tax asset values are the same as the tax asset values, set out in the table above.

Tax asset values at the end of the year

The table below shows the sum of tax asset values at the end of the year.

Sum of closing regulatory tax asset values ($000 nominal)	Current Period			Assessment Period	
	FY10	FY11	FY12	FY13	FY14
Closing regulatory tax asset values	250,102	250,318	261,304	306,552	373,583

	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Closing regulatory tax asset values	418,926	466,081	486,808	513,993	521,579

Tax depreciation

Clause 5.3.20(3) of the CPP IM defines tax depreciation for an asset as the amount determined by applying the tax depreciation rules to the regulatory tax asset value.

Some assets, mainly land and buildings, are not depreciated for tax purposes. We depreciate all of our other assets for tax purposes on a straight line basis.

The remaining lives we use for assets in our initial tax asset register are summarised in the table below.

Weighted average remaining tax lives by asset category (at 1/04/2009)

Asset category	Asset Life
Distribution	9.38
Buildings	44.87
Land	15.25
Vehicles	4.20
Non system (general)	12.16

For assets forecast to be added to our tax asset register in the future, we use the total asset lives shown in the table below.

Tax depreciation lives by asset type

Asset type	Asset Life	Asset type	Asset Life
Subtransmission network		***Switchgear***	
66 kV Overhead lines (concrete pole)	16.67	Air break isolators & surge diverters (66/33kV)	16.67
66 kV Overhead lines (wood pole)	16.67	Indoor circuit breakers (66/33/11kV)	16.67
66 kV Overhead lines (towers)	16.67	Outdoor circuit breakers and switchgear (66/33/11kV)	16.67
66 kV Underground cables (PILC and Oil filled)	16.67	11kV Disconnectors & dropout fuses	16.67
66 kV Underground cables (XLPE)	16.67	11kV Voltage regulators	16.67
33 kV Overhead lines (concrete pole)	16.67		
33 kV Overhead lines (wood pole)	16.67	***Low Voltage Distribution Network***	
33 kV Underground cables (PILC)	16.67	LV Overhead lines (concrete pole)	16.67
33 kV Underground cables (XLPE)	16.67	LV Overhead lines (wood pole)	16.67
Pilot / Communications Circuits	16.67	LV Underground cables (PILC)	16.67
Substations		LV Underground cables (XLPE)	16.67
Zone sub land	-	LV Customer service connections and link pillars	16.67
Zone sub site development and buildings	-		
Power Transformers	16.67	***Supporting or Secondary Systems***	
Protection (mixed digital & electromechanical)	16.67	Ripple Injection Plant	5.71
Protection (digital)	16.67	SCADA	5.71
Outdoor Structure (concrete pole)	16.67	Communications Equipment	5.71
Outdoor Structure (wood pole)	16.67	Metering systems	11.76
DC Supplies, batteries and inverters	16.67	Power factor correction plant	-
Other items		EDB-owned mobile substations and generators	11.75
		Other generation plant owned by the EDB	16.67
Distribution Network		Easements	-
11 kV Overhead lines (concrete pole)	16.67	Network Spares	16.67
11 kV Overhead lines (wood pole)	16.67		
11kV Underground cables (PILC)	16.67	***Non System Fixed Assets***	
11kV Underground cables (XLPE)	16.67	Information and Technology Systems	2.50
Distribution substations		Office Buildings, Depots and Workshops	9.00
Distribution sub land	-	Non Network Land	-
Distribution transformers (pole)	16.67	Office Furniture and Equipment	6.43
Distribution transformers (pad)	-	Motor Vehicles	7.23
Distribution substations mount (pole)	16.67	Tools. Plant and Machinery	1.50
Distribution substations mount (pad)	-		
Distribution substations mount (building)	-		

Regulatory tax asset values at the end of the year

The CPP IM defines regulatory tax asset values, at any point in the year based on the tax rules.

Consistent with the tax rules, the sum of regulatory tax asset values at the end of a regulatory year is equal to the sum of regulatory tax asset values at the start of the year plus the regulatory tax asset values of assets added to the regulatory tax asset register during the year, less the regulatory tax asset value of assets disposed from the regulatory tax asset register during the year, less tax depreciation, plus other adjustments to regulatory tax asset values.

The tables below shows the sum of regulatory tax asset values at the start and end of each year, including the relevant components, from FY10 to FY19, by tax asset category.

Distribution ($000 nominal)	Current Period			Assessment Period		CPP Period				
	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Opening regulatory tax asset values	218,722	218,432	218,166	232,566	266,126	307,460	333,677	373,964	392,340	410,935
Additions to the regulatory tax asset register	24,589	26,019	48,191	56,567	74,219	58,899	75,495	56,532	57,699	45,266
Disposals from the regulatory tax asset register	-	-	-	-	-	-	-	-	-	-
Tax depreciation	24,879	26,285	33,791	26,739	29,153	32,682	35,209	38,155	39,104	41,195
Closing regulatory tax asset values	218,432	218,166	232,566	262,394	307,460	333,677	373,964	392,340	410,935	415,007

System buildings ($000 nominal)	Current Period			Assessment Period		CPP Period				
	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Opening regulatory tax asset values	23,088	25,193	26,307	25,641	34,379	42,218	52,970	61,474	69,205	80,684
Additions to the regulatory tax asset register	2,614	1,674	(7,559)	8,739	7,839	10,752	8,504	7,731	11,479	8,199
Disposals from the regulatory tax asset register	-	-	-	-	-	-	-	-	-	-
Tax depreciation	509	560	(6,893)	-	-	-	-	-	-	-
Closing regulatory tax asset values	25,193	26,307	25,641	34,379	42,218	52,970	61,474	69,205	80,684	88,883

System land ($000 nominal)	Current Period			Assessment Period	
	FY10	FY11	FY12	FY13	FY14
Opening regulatory tax asset values	6,859	7,236	7,493	8,239	8,904
Additions to the regulatory tax asset register	397	277	746	705	-
Disposals from the regulatory tax asset register	-	-	-	-	-
Tax depreciation	20	20	-	40	20
Closing regulatory tax asset values	7,236	7,493	8,239	8,904	8,884

	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Opening regulatory tax asset values	8,884	9,691	10,240	10,338	10,745
Additions to the regulatory tax asset register	826	569	118	426	314
Disposals from the regulatory tax asset register	-	-	-	-	-
Tax depreciation	20	20	20	20	20
Closing regulatory tax asset values	9,691	10,240	10,338	10,745	11,039

Non system fixed assets ($000 nominal)	Current Period			Assessment Period	
	FY10	FY11	FY12	FY13	FY14
Opening regulatory tax asset values	15,071	15,693	14,057	16,222	19,131
Additions to the regulatory tax asset register	4,974	2,556	5,501	5,369	24,494
Disposals from the regulatory tax asset register	40	6	50	-	9,320
Tax depreciation	4,312	4,186	3,286	2,460	3,294
Closing regulatory tax asset values	15,693	14,057	16,222	19,131	31,010

	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Opening regulatory tax asset values	31,010	29,275	27,783	26,147	25,732
Additions to the regulatory tax asset register	3,496	3,937	3,627	4,833	2,804
Disposals from the regulatory tax asset register	-	-	-	-	-
Tax depreciation	5,231	5,429	5,262	5,247	5,605
Closing regulatory tax asset values	29,275	27,783	26,147	25,732	22,931

Acquired assets ($000 nominal)	Current Period			Assessment Period	
	FY10	FY11	FY12	FY13	FY14
Opening regulatory tax asset values	-	-	-	-	4,329
Additions to the regulatory tax asset register	-	-	-	4,329	1,655
Disposals from the regulatory tax asset register	-	-	-	-	-
Tax depreciation	-	-	-	-	292
Closing regulatory tax asset values	-	-	-	4,329	5,692

	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Opening regulatory tax asset values	5,692	17,062	21,183	20,458	19,069
Additions to the regulatory tax asset register	11,770	5,213	727	-	-
Disposals from the regulatory tax asset register	-	-	-	-	-
Tax depreciation	399	1,092	1,453	1,389	1,256
Closing regulatory tax asset values	17,062	21,183	20,458	19,069	17,813

Adjustments to the tax register ($000 nominal)	Current Period			Assessment Period	
	FY10	FY11	FY12	FY13	FY14
Opening regulatory tax asset values	(16,279)	(16,452)	(15,704)	(21,363)	(22,586)
Additions to the regulatory tax asset register	(2,098)	(1,343)	(753)	(880)	(7,970)
Disposals from the regulatory tax asset register	-	-	7,002	-	(7,010)
Tax depreciation	(1,926)	(2,091)	(2,095)	(1,858)	(1,863)
Closing regulatory tax asset values	(16,452)	(15,704)	(21,363)	(20,386)	(21,682)

	CPP Period				
	FY15	FY16	FY17	FY18	FY19
Opening regulatory tax asset values	(21,682)	(23,750)	(28,563)	(31,681)	(33,173)
Additions to the regulatory tax asset register	(4,240)	(7,060)	(5,612)	(4,139)	(3,629)
Disposals from the regulatory tax asset register	-	-	-	-	-
Tax depreciation	(2,172)	(2,247)	(2,494)	(2,647)	(2,708)
Closing regulatory tax asset values	(23,750)	(28,563)	(31,681)	(33,173)	(34,095)

We note that the tax asset category labelled 'Adjustments to the tax asset register' includes a number of specific tax items which we manage outside our tax asset register. One such item is insurance proceeds relating to the Armagh St disposal. For tax purposes we are disposing of Armagh St in two parts. In FY12 we received insurance proceeds, and accounted for a tax disposal outside the tax asset register. In FY14 we fully disposed of the assets in the tax asset register and reversed the disposal outside the register. This is shown in the table above.

Adjustments to the tax asset register also include capital contributions from FY13 onwards. Historically, we have deducted the value of capital contributions from the value of tax additions for specific assets. Allocating capital contributions to specific tax assets is more difficult when forecasting, therefore we have treated them separately, as a negative tax asset. For depreciation purposes, we assume the same asset lives as for similar assets in the tax asset register (16.67 years).

Acquired assets

In Section 7.5.5 we discussed how the assets we acquire from Transpower will be added to the RAB. We will add the same assets to our tax asset register as we add to the RAB.

Because Transpower is a regulated supplier, Transpower's regulatory tax asset values, at each relevant acquisition date, are included in our tax register at that date. Since these assets will only be used to provide electricity distribution services (ie: they require no allocation to other services), the regulatory tax asset values are the same as the tax asset values.

Transpower has provided us with actual tax asset values for the assets included within the Papanui acquisition in August 2012. We have recorded these assets in our tax asset register at the tax asset values provided by Transpower.

For our forecast acquisitions from FY14 to FY17, Transpower has not provided us with tax asset values for the assets to be acquired. We have therefore estimated these future values. We do this by using the difference between RAB and tax asset values for the Papanui assets, and the RAB values for the other acquisitions. For each acquired asset, we use the proportional difference between RAB and tax asset values for assets with similar remaining lives in the Papanui acquisition, and apply this to the acquired asset's RAB value – deriving an estimate of each asset's tax asset value on the acquisition date.

The table below shows the sum of the regulatory tax asset values for the Papanui acquisition in FY13, and our estimates of the sum of the regulatory tax asset values for the forecast acquisitions.

Sum of regulatory tax and RAB values on acquisition date ($000 nominal)	Assessment Period		CPP Period		
	FY13	FY14	FY15	FY16	FY17
RAB value	4,188	2,700	16,784	9,419	1,198
Regulatory tax value	4,329	1,655	11,770	5,213	727

Tax disposals

In Section 7.5.6 we discussed our forecast disposals of assets associated with our Armagh Street head office site in FY14.

We dispose of the same assets from the tax asset register. However, due to differences between the regulatory and tax rules we do not dispose of all of them in FY14.

The assets have been partially disposed of for tax purposes during FY12. This was the year in which we received insurance proceeds relating to these assets. The remaining tax asset values will be disposed of in FY14, when we move to our new headquarters at Wairakei Road.

The table below shows the sum of the regulatory tax asset values for disposed assets, from FY11 to FY14. Consistent with the discussion in Section 7.5.6, we are not expecting to dispose of any assets during the CPP regulatory period.

Sum of regulatory tax asset values on disposal date ($000 nominal)	Assessment Period			CPP Period	
	FY10	FY11	FY12	FY13	FY14
Regulatory tax values	40	6	7,052	-	2,310

7.7 Cost of capital

IM 5.4.27 and 5.3.22 - 5.3.32

7.7.1 75th percentile estimate of WACC

Clause 5.4.27(1) of the IMs requires that a CPP proposal must identify the 75th percentile estimate of WACC used for the purpose of calculating BBAR for the next period.

We also provide historical the WACC which we use to determine the value of claw-back, which applies in FY11 - FY14.

75th percentile estimate of WACC

The table below shows the 75th percentile estimates of WACC used to determine BBAR.

75th percentile estimate of WACC	Current Period			Assessment Period	
		FY11	FY12	FY13	FY14
WACC		8.77%	8.77%	8.77%	8.77%

	CPP Period				
	FY15	FY16	FY17	FY18	FY19
WACC	6.92%	6.92%	6.92%	6.92%	6.92%

CPP WACC

Clause 5.4.27(2) of the IMs states that the 75th percentile estimate of WACC used to determine amounts for BBAR for the next period must be the amount, corresponding to the EDB's proposed duration of the CPP regulatory period, most recently published by the Commission (in accordance with clause 5.3.29) prior to submission of the CPP proposal.

The most recent publication by the Commission of WACC estimates for a CPP for EDBs occurred on 28 September 2012.[29] That document states that

> *Vanilla WACCs have been estimated for inclusion in any CPP proposal made by an Electricity Distribution Business (EDB). The 75th percentile estimate of vanilla WACC for CPP periods of three years is 6.63%, of four years is 6.77% and of five years is 6.92%.*

As stated in Section 5.1 of this proposal, it is proposed that Orion's CPP regulatory period applies for a period of five years. Accordingly a CPP WACC of 6.92% is to be used.

DPP WACC

The IMs do not specify which 75th percentile estimate of WACC should be used to determine the amounts for BBAR for the purpose of calculating claw-back.

The regulatory WACC that currently does apply to Orion during the claw-back period is the 2010 DPP WACC.

This applies for the current five year DPP period, FY11-FY15. Our CPP will come into force in FY15, and for the reasons outlined above, the CPP WACC will apply in that year (ie: will replace the DPP WACC).

The 75th percentile estimate of WACC which applies to the current electricity distribution DPP is stated in the Determination published by the Commission on 3 March 2011.[30] The document states that:

> *"the Commission has determined a 75th percentile estimate of the vanilla WACC of 8.77% for the first DPP regulatory period (commencing April 2010)."*

Thus we have applied the DPP 75th percentile estimate of WACC of 8.77% for the purpose of deriving BBAR in the claw-back period (ie: from 1 September 2010 – 31 March 2014). While this has not been specified in the IMs, we believe this is a reasonable approach because it is consistent with the counterfactual price-quality value that would have applied to us over that period.

7.7.2 Term credit spread differential allowance

Clause 5.4.27(3) of the IMs requires that a CPP proposal must contain all data, information, calculations, Bloomberg print-outs and assumptions used to determine any proposed term credit spread differential.

As stated in Section 7.3.9, we have not included any term credit spread differential allowance in our proposal.

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[29] Commerce Commission: Cost of capital determination for electricity distribution businesses to apply to a customised price-quality path proposal [2012] NZCC 25, 28 September 2012

[30] Commerce Commission: Determination of the Cost of Capital for Services Regulated under Part 4 of the Commerce Act 1986, Pursuant to Decisions 709, 71, 711, 712 and 713, Decision Number 718, 3 March 2011

The term credit spread differential allowance is defined in Part 1 of the IMs as the sum of term credit spread differentials.

As defined in clause 5.3.32(1) of the IMs, a term credit spread differential can only be determined in respect of a qualifying debt. We do not have any qualifying debt.

Clause 5.3.30(1) defines a qualifying debt as a line of debt with an original tenor greater than the length of the proposed CPP regulatory period, in this case five years, which is issued by a qualifying supplier. Clause 5.3.30(2) of the IMs defines a qualifying supplier as a CPP applicant whose debt portfolio, at the date that the supplier's audited financial statements were published most recently prior to the CPP application, has a weighted average original tenor greater than the length of the CPP regulatory period.

We do not have any lines of debt with a tenor longer than five years. We are therefore not a qualifying supplier, nor do we have any qualifying debt. We therefore do not propose any term credit spread differentials.

7.7.3 Cost of debt

We described in Section 7.2.2 how we use the cost of debt to determine the value of claw-back and to determine the amount to be recovered in each year from FY15. We stated that we use the current DPP cost of debt to determine the value of claw-back as at 1 April 2014, and then the CPP cost of debt to determine the amount to be recovered in each year of the CPP period.

In each case, we use the cost of debt that corresponds to the DPP and CPP WACCs that we use to determine the return on capital element of BBAR (and as we outlined in Section 7.7.1 above).

The table below shows the two cost of debt values used, alongside the corresponding WACCs.

WACC and cost of debt

	Cost of debt	WACC
CPP	5.89%	6.92%
DPP	7.93%	8.77%

7.8 New pass through costs

IM 5.4.32

Clause 5.4.32 of the IMs requires that a CPP proposal must contain details of any cost, other than those pass-through costs specified in clause 3.1.2(2) of the IMs, that is sought to be specified as a new pass-through cost in a CPP determination, in accordance with clause 3.1.2(1)(b) of the IMs.

We do not seek any new pass-through costs to be specified in a CPP determination in response to this CPP proposal.

7.9 Recoverable costs of making a CPP application

IM 5.4.33 and 3.3.1

Recoverable costs are cost items which are included within the total revenue collected from consumers, but which are considered outside the framework for determining MAR. They typically reflect items where it is deemed that the cost is outside the control of the EDB.

The amounts for these items are determined after the price path is set, and added to the previously determined MAR to determine actual prices in a given future year.

Clause 3.1.3(1) of the IMs provides a list of items which are classed as recoverable costs. Some of those are specific to CPPs, including:

h) a standard application fee for a CCP proposal under 53Q(2)(c), subject to the proviso specified in subclause (5)
i) a fee notified by the Commission as payable by the EDB in respect of the Commission assessing a CPP proposal and determining a CPP in accordance with s 53Y of the Act, subject to the proviso specified in subclause (5)
j) a fee payable to a verifier subject to the requirement specified in subclause (3)
k) any auditor’s cost incurred for the purpose of meeting clauses 5.1.4 or 5.5.3, subject to the requirement specified in subclause (3)
l) a fee payable to an engineer for the purpose of meeting a requirement of clauses 5.4.5(c) or 5.4.12(4)(c), subject to the requirement specified in subclause (3).

Subclause (3) and (5) noted above require the amount to be specified in a CPP Determination and do not apply if the CPP proposal is discontinued by the Commission.

Orion proposes that recoverable costs relevant under each of sub-clauses h) – j) are included in our CPP Determination.

IM information requirements

Clause 5.4.33 of the CPP IM requires that where a CPP applicant seeks specifications of items as recoverable costs, a CPP proposal must provide, in relation to any auditor, verifier or engineer who was engaged to provide an opinion on some aspect of this CPP proposal:

- any document making public or limited circulation request for proposals to carry out the work
- the terms of reference for the work
- invoices for services undertaken in respect of the work
- receipts for payment by Orion.

We discuss these below.

7.9.1 Fees payable to the Commission

The standard application fee noted in sub-clause h) is specified in the Commerce Act (Fees) Amendment Regulations 2012, section 4. It is $23,000. That fee accompanies this proposal.

We anticipate the Commission's assessment and determination fees noted in i) will be communicated to us on completion of the assessment and determination process, and accordingly will be able to be specified in the CPP Determination at that time.

7.9.2 Fees payable to the verifier

Sub-clause j) refers to fees payable to the verifier.

We issued a Request for Proposal to act as verifier to four prospective candidates. We received written proposals from two candidates. We evaluated both proposals received, interviewed the candidates and conducted reference checks. The interviews enabled us to further assess the candidates experience and understanding of the verifier role and process. After the interviews both candidates resubmitted their proposals.

We are required to obtain the Commission's approval of the verifier. We wrote to the Commerce Commission on 1 August 2012 advising them that our preferred candidate was Geoff Brown and Associates (GBA). This correspondence included our rationale as to why we believe he is suitably qualified and experienced. On 9 August 2012 the Commission approved GBA as the verifier of our CPP proposal.

Included in Appendix 17 is the evidence required to support our proposal that GBA's fees are included in our CPP Determination as a recoverable cost. This includes:

- request for proposals for verifiers
- terms of engagement with GBA
- tripartite deed between the Commission, GBA and ourselves
- invoices we have received from GBA to 31 December 2012.

Note that the verifier's role has continued beyond December 2012 and we will be submitting additional invoices to be included in our proposed recoverable cost amount, once GBA's work is complete.

7.9.3 Fees Payable to the auditor

Sub-clause k) refers to auditor's costs incurred in relation to the work undertaken in respect of IM clauses 5.1.4 and 5.5.3. Part 1 of the IMs specifies that where an EDB is a public entity, the auditor must be the Auditor General. Orion is a public entity (as defined in section 4 of the Public Audit Act 2001) and hence our CPP proposal has been audited by the Auditor General. Our request for proposal for this work was therefore directed to Audit New Zealand, which undertakes our audit work on behalf of the Auditor General.

Appendix 18 includes the following documents pertaining to our engagement with Audit New Zealand and their terms of reference:

- assurance engagement letter
- invoices we have received to 31 December 2012.

As Audit NZ has only just completed their services, final invoices have not yet been received. However, copies of invoices received to 31 December are included in Appendix 18. It is also possible Audit NZ will be required to extend their role after our CPP application has been submitted. Additional fees will be incurred if they are retained for further audit work in this respect.

7.9.4 Fees payable to the engineer

Sub-clause l) refers to fees payable to an engineer. We engaged Linetech Limited to provide the engineering report specified in clause 5.4.5(c) of the IMs in relation to the quality standard variation.

We issued a Request for Proposal (RFP) to act as an independent engineer and provide reports on certain aspects of our CPP proposal to five prospective candidates. Three candidates declined to provide a proposal and one could not comply with our requirements. Accordingly, we had one conforming proposal from LineTech Consulting. We evaluated the proposal received and accepted LineTech Consulting's proposal.

Our request for proposal specified that we may also require a report on alternative depreciation methods, however this was not required.

Included in Appendix 19 are:

- RFP for independent engineer services
- LineTech's response to our RFP
- Orion's acceptance of the RFP
- invoices we have received.

7.9.5 Summary of new recoverable costs

The following table summarises the recoverable costs we propose are included in our CPP Determination relevant to IM 3.3.1(1)(h)-(l).

CPP proposal recoverable costs ($000)			
IM clause	**Payments made to date**	**Costs yet to be incurred**	**Total**
3.1.1(1)(h) – application fee	23	0	23
3.1.1(1)(i) – Commission's fees	0	unknown	unknown
3.1.1(1)(j) – verifier fees	141	unknown	unknown
3.1.1(1)(k) – auditor costs	130	unknown	unknown
3.1.1(1)(l) – engineer fees	15	-	15

As illustrated above, we do not know the total value of items 3.1.1(1)(i)-(l) at this time. We will be able to provide additional information in respect of items (j) – (l) before our

CPP is determined. We anticipate that the Commission will provide the information relevant to (i) for the purpose of the Determination.

We note that other recoverable costs, specified within 3.3.1(1) (b) – (f) are also relevant to our CPP Determination. These are the same as those which apply under our current DPP Determination. No further information is provided in respect of those costs as part of this CPP proposal.

7.10 Appendices and supporting documents and spreadsheets

Section 7 – Appendices	
Appendix	**Title**
1	Expert review by Jeff Balchin
2	Expert review by James Mellsop, NERA
10	Regulatory decisions regarding catastrophic events
11	Marsh Report on Insurance
12	Quantity growth trends
13	Detailed calculations for weighted average growth in quantities
14	SKM on Initial RAB adjustments
15	Depreciation by asset type
16	Engineer’s report on non standard asset lives
17	Recoverable cost evidence – verifier
18	Recoverable cost information – auditor
19	Recoverable cost information - engineer

Section 7 – Supporting documentation
Description
Pricing methodology
Donaggio and Bright, Canterbury Irrigation Peak Electrical Load – Spatial Pattern across Distribution Networks, 2011

Responses to section 53ZD notices provided to the Commission in respect of financial information pertaining to FY10
Orion report on how RAB database is prepared
NW70.00.45 connections and extension policy

Section 7 - Accompanying spreadsheets

Name	Description
BBAR Final.xlsm	BBAR model
RAB Final.xlsx	System asset RAB model
NSFA – Roll Forward Summary Final.xlsx	Non-system asset RAB model
Acquired Assets Final.xlsx	Acquired assets model
TAM Final.xlsx	Tax asset model
Nominal Capex Final.xlsx	Nominal capex model
Nominal Opex Final.xlsx	Nominal opex model
Cost Escalator Final.xlsx	Cost escalator model
Other Inputs Final.xlsx	Other inputs model
Projected chargeable quantities – for CPP Final.xlsm	Growth in quantities model

8 Expenditure overview

8 Expenditure overview

IM 5.4.29 - 5.4.31, 5.5.2, Schedule E, Schedule F, Schedule G

8.1 Introduction and summary

8.1.1 Introduction

The purpose of this section of our CPP proposal is to set out how our quantitative capital and operating expenditure information has been compiled and to summarise our past and forecast expenditure.

More detailed information is contained in Section 9, which responds to the specific information requirements set out in Schedule D of the IMs for the qualitative information necessary to explain our capex and opex proposals.

8.1.2 Summary of expenditure plan

The key objective of our capex and opex programme is to restore network resilience and meet the long term needs of our consumers for a safe, reliable and cost effective electricity distribution service.

In our proposed capex programme we will:

- build new assets to restore resiliency to our network and to meet new demand from consumers (including for the rebuild and new subdivisions)
- purchase local spur assets from Transpower and integrate them into our subtransmission network
- replace existing assets to ensure we continue to meet our safety and network performance targets
- construct a new head office as our previous office buildings have been demolished following extensive earthquake damage.

In our opex programme we will:

- maintain our network and operate it in accordance with good industry practice
- respond to unplanned events in a timely and effective way
- accommodate the Christchurch rebuild
- ensure the performance of our assets is maintained, consistent with consumers needs.

We aim to ensure our expenditure is prudent and in the long term interests of our consumers. However, it has been and continues to be necessary to increase our opex and capex, over pre earthquake levels, for the foreseeable future. This increase is necessary to restore the resilience in our network and improve our service levels to those which are more consistent with the level our consumers expect from us. We are very mindful of the impact of this on our costs to deliver electricity and we continue to seek to find ways to improve our planning and project execution. We also aim to achieve a prudent and appropriate return for our shareholders.

Capex forecasts

Our capex projects and programmes are predominantly associated with network security, resilience, consumer demand and maintaining our service capability. Before spending capital on our network, we consider a number of options including those available in demand side management and distributed generation.

The earthquakes caused significant damage to our network. We are proud of our pre-earthquake network architecture and engineering strategies to minimise the impacts of such events and we are pleased with our operational response during the response and recovery phases. There is much to be learnt from an event of this scale and this, coupled with permanent network damage, is resulting in inevitable changes to our pre earthquake network development plans.

The key driver for our urban network capex programme over the CPP period is our drive to restore network resiliency, and accommodate the post earthquake relocations and rebuild. The acquisition of Transpower spur assets located within our network supply area is a core part of our urban subtransmission development plan. The key driver for our rural capex programme is meeting growth (particularly relating to the dairy industry) and maintaining appropriate quality of supply.

Opex forecasts

Our opex plans have been prepared consistent with our overarching asset management planning practices, which reflect our lifecycle management strategy for our electricity assets. We use condition based maintenance practices for our network equipment and this is reflected in this plan. We aim to manage our assets prudently to provide a reliable and appropriate quality of service for the long term benefits of our consumers.

Our support activities, those not directly related to constructing, maintaining and renewing our electricity distribution system, support our core asset management processes. Our infrastructure team is responsible for developing and implementing our asset management policies and practices. Our corporate teams (corporate, finance, commercial, IT, HR, communications) provide the necessary systems, management support and direction to enable these functions to operate efficiently and effectively.

Our opex on network assets is dominated by scheduled maintenance. FY11 and FY12 are exceptions to this, as we incurred large emergency maintenance expenditure following the earthquakes in these years.

Our scheduled maintenance forecast increases in FY13 and continues to be higher than what we had spent pre-earthquakes. This reflects two key factors: the need to restore the condition of our damaged network assets; and the cost pressures we face in our local contract market due to the accelerating construction activity in Canterbury.

Our forecast opex also includes significant expenditure in network and corporate support services which are predominantly office based and support our core asset management processes. Our infrastructure team is responsible for developing and implementing our asset management policies and practices. Our corporate teams provide the necessary systems, management support and direction to enable these functions to operate efficiently and effectively.

8.1.3 Information presented in Section 8

The remainder of this section of the proposal is structured as follows:

- Section 8.2 describes how our capex and opex information is included in our CPP proposal
- Section 8.3 summarises our capex and opex expenditure
- Section 8.4 summarises the independent verification process to review our capex and opex plan
- Section 8.5 describes how we have compiled our capex and opex and presented these in the proposal. It also includes a brief description of our capex and opex
- Section 8.6 concludes this section of the proposal
- Section 8.7 lists the appendices and other supporting documents which support Section 8.

8.2 Capex and opex quantitative information

The CPP IM prescribes how we are to present our capex and opex. It sets out requirements for quantitative information (the value of capex and opex) and qualitative information (our supporting evidence and explanations). This Section 8 focuses on the quantitative information and how we have derived it.

Capex and opex information has been provided for:

- a five year historical period (FY08 to FY12) (**the current period**)
- a two year assessment period (FY13 to FY14) (**the assessment period**)
- a five year forecast period (FY15 to FY19) (**the CPP period**).

This is consistent with the requirements of clauses 5.4.29 - 5.4.31 of the IMs which prescribe the use of the Regulatory Templates which are in Schedule E of the IMs, and which are to include information relevant to the current, assessment and CPP periods. In addition we note that the CPP IM refers to the **next period** which incorporates the assessment period and the CPP period.

Our CPP proposal includes a **claw-back period** which commences on 4 September 2010 and ends on 31 March 2014. This spans all of the Assessment Period and part of the Current Period.

We have assumed for the purpose of deriving financial data that the claw-back period commences on 1 September 2010, three days prior to the initial earthquake. This is a practical assumption, as it is not possible to identify daily expenditure but it is possible to identify monthly expenditure. As we also identify revenues for the entire month of September, which are offset against the expenditures for the month for the purpose of assessing claw-back, we believe that any potential inaccuracy in the value of claw-back will be immaterial.

The Schedule E regulatory templates are compiled in spreadsheets and accompany this proposal. In accordance with clause 5.4.29(3) all underlying formula and input data are accessible in the spreadsheets provided. These are listed at the end of this section. Schedule E requires the project and programme capex and opex data (to be included in Tables 4, 5 and 6 as described below) to be presented in nominal terms. The accompanying spreadsheets also include each Table 4, 5 and 6 presented in real terms (ie: they include forecast expenditure for FY14 - FY19 presented in FY13 terms, prior to the application of input cost escalators).

The templates comprise the following:

Schedule E templates

Table	Template	Description
Table 1	Top 5	Presents the five largest capex and five largest opex projects/programmes by value across the next period (FY13 – FY19)
Table 2	Capex summary	A summary of the value of all capex projects/programmes by service category and capex expenditure category for the next period (FY13 – FY19)
Table 3	Opex summary	Table 3(a) a summary of the value of all opex projects/programmes by service category and opex expenditure category for the next period (FY13 – FY19) Table 3(b) has that opex which is proposed to be included as controllable opex and Table 3(c) the residual opex (ie: that not included as proposed controllable opex). We have not included any controllable opex in our proposal (as described further in Section 9.24). Table 3(c) is the same as Table 3(a)
Table 4	Capex project / programme	Table 4 is repeated for each capex project or programme. We have 44 capex projects/programmes. Each Table 4 includes: • a project/programme description • relevant service category • relevant capex category • the value of capex by asset category and asset type • the value of each project/programme by source, (who has done or is expected to do the work) This information is provided for the current and next periods (FY08 – FY19)
Table 5	Opex project / programme	Table 5 is repeated for each opex project or programme. We have 34 opex projects/programmes. Each Table 5 includes: • a project/programme description

		• relevant service category • relevant opex category • the value of opex by asset category and asset type • the value of each project/programme source. This information is provided for the current and next periods (FY08 – FY19)
Table 6a	Overheads	Table 6a sets out the general management, administration and overheads opex category and the network management and operations opex category. It includes a summary of the value of each expenditure type for the current and next periods (FY08 – FY19)
Table 6b	Non system capex	Table 6c sets out non system capex for the current and next periods (FY09 – FY19)
Table 7	Unit rate escalators	Table 7 describes for each cost input, the escalators used in the capex and opex forecast and the quantum of cost to which each escalator is applied. This is provided for the current, assessment and next periods (FY13 - FY19)
Table 8	Cost allocation A	Table 8 summarises for FY13 opex (year 1 of the assessment period), the directly attributable and not directly attributable opex for each opex category. Our approach to cost allocation is set out in Section 7.5
Table 9	Cost allocation B	Table 9 summarises our cost allocation for FY14 (year 2 of the assessment period)

We have made minor modifications to the versions of the templates included in Schedule E of the IMs. These modifications have been necessary due to:

- errors and omissions we have discovered in the templates
- the transitional information provisions in the CPP IM which allows for departures from the prescribed cost categories included in the templates
- damage to our financial systems and records which occurred during the 22 February 2011 earthquake. This damage has reduced the historical information available to us and therefore our ability to fully populate some of the capex templates.

We have However, presented information which is consistent with the underlying intent of Schedule E and for the most part we have included additional information to that prescribed. We have discussed these modifications with the Commission, who have indicated that they do not believe they require an IM variation, as permitted under section 53V(c) of the Commerce Act. A list of our modifications and the reasons for those are set out in Appendix 5. Further explanation is included throughout the remainder of this Section 8.

8.3 Expenditure summary

Our capex and opex comprises the following core activities, which are consistent with the way in which we manage our business and plan our future needs.

Capex	**Network**	**Major Projects**	
		Reinforcement	
		Replacement	
		Customer Connection / Network Extension	
		Underground Conversions	
		Asset Acquisitions	
	Non Network	**Non System Assets**	
Opex	**Network**	**Maintenance**	**Emergency**
			Scheduled
			Non-Scheduled
	Non Network	**Network Management and Operations**	
		General Management, Administration and Overheads	

Our CPP proposal includes capex and opex for FY08 to FY19. Data for FY08 to FY12 reflects actual expenditure incurred, FY13 reflects our budgets for the current year, and FY14 to FY19 reflects our forecasts.

The FY14 to FY19 information is shown in real and nominal terms. Nominal forecasts incorporate input price inflation which is relevant to our expenditure plan. This reflects the local Canterbury prices we will incur in delivering our capex and opex.

Our capex data is converted to commissioned asset information for our price path modelling. This is explained in Section 7.5.5 of this proposal.

This proposal includes our forecast capex projects and programmes to restore network resilience. We forecast we will:

- build new assets to restore resiliency to our network and to meet new demand from consumers (including for the rebuild and new subdivisions)
- purchase local spur assets from Transpower and integrate them into our distribution network
- replace existing assets.

Our opex programme will enable us to:

- maintain our network and operate it in accordance with good industry practice
- respond to unplanned events in a timely and effective way
- accommodate the Christchurch rebuild

- ensure the performance of our assets is maintained, consistent with consumers needs.

We aim to ensure that our expenditure is prudent and in the long term interests of our consumers. However, it has been and continues to be necessary to increase our opex and capex, compared with pre earthquake levels, for the foreseeable future. This increase is necessary to restore the resilience in our network and restore our service levels to those which are more consistent with the level our consumers expect from us. We are very mindful of the impact of this on our costs to deliver electricity and we continue to seek to find ways to improve our planning and project execution.

We note that there is increasing pressure in Canterbury for infrastructure resources and we are starting to see this emerge in upwards pressure on contract prices and labour costs. We are confident that our competitive tendering processes will continue to ensure that we are able to deliver our planned projects as efficiently as possible but we do not believe that we will be able to maintain the cost of labour for network construction and maintenance at pre earthquake levels, due to local demand pressures.

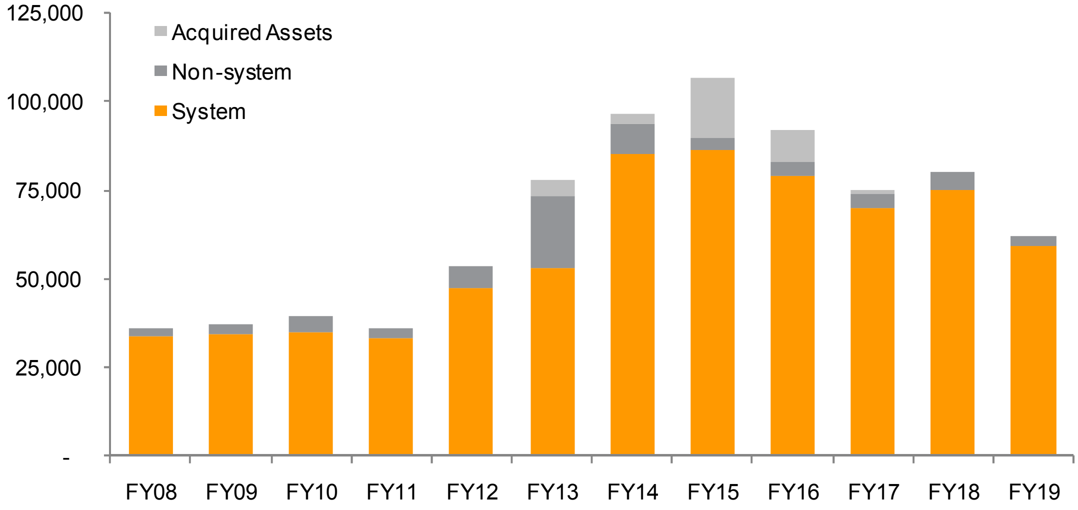
The following table demonstrates our expected labour cost increases for FY14 to FY19. These are discussed more fully in Section 9.26 along with our forecast price increases for other non labour inputs. They are included in the nominal capex and opex data presented throughout this section.

Forecast percentage change in labour input prices

Index	FY14	FY15	FY16	FY17	FY18	FY19
Network construction and maintenance	7.50%	7.50%	7.50%	5.00%	5.00%	5.00%
Non network	1.92%	1.97%	2.61%	2.16%	2.16%	2.16%

Our capex and opex has been designated as system (network) and non-system (non-network) expenditure. System expenditure occurs mainly in the field, on and around our electricity lines network. Non network expenditure is mainly office based, and provides the support systems and services necessary to ensure we can supply electricity to our consumers, via our network and its associated secondary assets.

Nominal capex ($000)

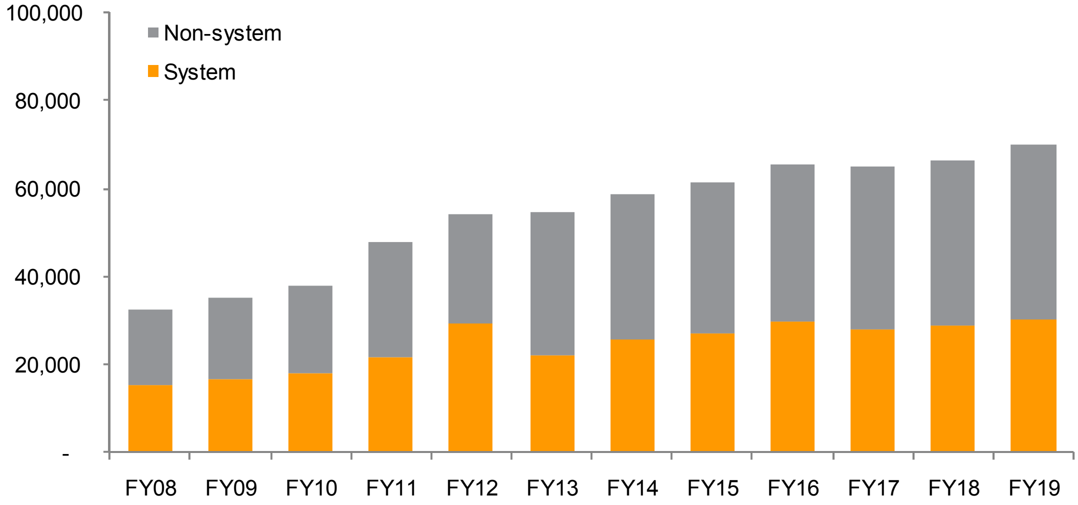


Our capex is dominated by system capex: expenditure on our distribution system and supporting secondary assets. Our capex also includes acquisitions of local spur assets from Transpower, which commence in FY13 and are forecast to continue through to FY17. These are strategic purchases integrating Transpower’s dedicated 66kV assets used solely to supply our network, into the core sub transmission infrastructure of our network.

Our system capex category increases immediately after the earthquakes in FY12 and FY13, and then again in FY14 reflecting our major projects in the recovery phase. This increase starts to tail off by the end of the CPP period as our major network restoration projects are completed.

Our non system capex category is relatively minor except in FY12 to FY13. This reflects the immediate need to invest in office accommodation following extensive earthquake damage to our now demolished head office site. We plan to move to the new head office site when its build is complete in mid 2013.

Nominal opex ($000)



Approximately 45% of our opex is system opex incurred directly on the network. This largely reflects ongoing maintenance and repairs. The remainder is non system opex which reflects the corporate and infrastructure support and operational services for the network.

The step up in FY11 and FY12 in system opex reflects the emergency maintenance work undertaken as a result of earthquake damage to our assets. Further forecasts are also included in future years in anticipation of ongoing unplanned work due to asset failure (especially 11kV cables) and third party damage to our assets during the city rebuild. These are impacted by our forecast increases in labour costs compared to historical levels.

Abnormal corporate opex is also evident in FY11 to FY13 reflecting the need to manage the consequences of the earthquakes on our business and employees. Ongoing non system opex is reasonably constant, with notable features being increases in insurance costs and also in the network management support functions which support our field operations.

A detailed explanation of the expenditure forecast is provided in the remainder of Section 8 and Section 9 of this proposal, and in the supporting information which has been provided in the appendices.

Presentation

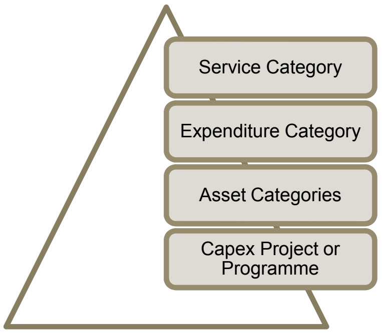
As required by clause 5.4.29, we have presented the capex and opex information by:

- service category
- expenditure category
- asset category (and asset type)
- individual project and programme.

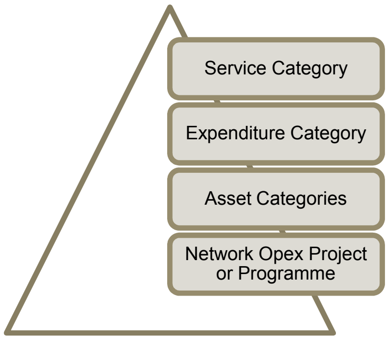
In order to achieve this, each network project or programme is assigned to a service category and an expenditure category. Each non network project is assigned an expenditure category (but not a service category). The total expenditure for each project and programme is allocated across asset categories and asset types, with the exception of corporate and network support opex (which is not directly related to assets).

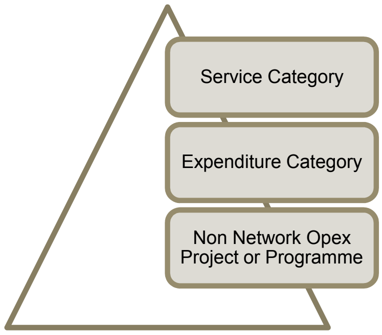
This presentation format is summarised in the following diagrams.

Information hierarchy for capex projects and programmes



Information hierarchy for opex projects and programmes





A further CPP IM requirement is that the expenditure on each network project or programme is assigned to a source - the party which undertakes, or is expected to undertake the work.

Opex is also classified as either controllable or other opex. As stated above, we have included no controllable opex in our proposal. This is explained further in Section 9.24.

8.4 Independent verifier

IM Schedule F and Schedule G

8.4.1 Appointment of the verifier

Clause 5.5.2 requires that a CPP proposal must be examined by an independent verifier before it is submitted. The role of the verifier is to review the capex, opex and demand information which supports our proposal. The objectives of the pre-submission verification are twofold:

- to promote certainty for CPP applicants as to how the proposed capex and opex will be assessed
- to assist the Commission in meeting its statutory timeframes for making a CPP Determination.

CPP applicants have an opportunity to consider the verifier's draft report and address any concerns raised by the verifier before submitting the CPP proposal to the Commission for assessment. This is intended to allow the Commission to focus on the most important aspects of the CPP proposal during its assessment.

We appointed Geoff Brown and Associates (GBA) as our independent verifier. The Commission approved GBA prior to its appointment. The process for engaging a verifier is set out in Schedule F of the CPP IM, which we followed. GBA has a duty of care to the Commission in this role and has met the appropriate independence requirements.

8.4.2 Role of the verifier

The verifier must undertake their review in accordance with the terms of reference for the independent verifier as specified in Schedule G of the IMs. GBA's verification does not involve a review of the entire CPP proposal, it is limited to a review of quantitative and qualitative information on specific matters, namely our:

- service categories, measures and levels
- cost allocation
- capex and opex
- detailed consideration of twenty identified capex and opex projects or programmes plus two corporate capex projects
- capital contribution revenue
- demand forecasts
- non standard depreciation.

The verifier must consider the completeness or otherwise of the CPP proposal and identify key issues and additional information requirements for the Commission in respect of the topics listed above.

8.4.3 Verifier's process

On 19 November 2012 we provided GBA with our draft CPP proposal, supporting project and programme descriptions, supporting policies and procedures and capex and opex templates in spreadsheet form. With the agreement of the Commission we provided GBA information about our top 10 projects and programmes on 31 October 2012. This initial information was provided to GBA on the proviso that no conclusions would be drawn before all information had been received and assessed. On 3 December 2012 GBA selected a further 10 identified projects and programmes for detailed investigation.

A full list of our projects and programmes is included in Section 8.5.1 below which also shows those selected as identified projects for detailed investigation by GBA.

GBA studied our draft CPP proposal, the schedules and supporting qualitative information such as policies, standards, technical specifications and procedures relating to capex, opex and demand. Much of this information is included in Section 9 of this proposal, and relevant supporting appendices. Orion responded to the questions posed by GBA and provided additional material as requested throughout December and January.

GBA provided us with its draft verification report. We considered that draft report before finalising our proposal. Once our proposal was finalised, GBA finalised its report, which accompanies this proposal.

8.5 Approach to compiling our capex and opex

IM 5.4.28 – 5.4.31

8.5.1 Projects and programmes

Our capex and opex comprise a number of different projects and programmes. Each of these has been assigned a service category and a capex or opex category as required by clause 5.4.30 of the CPP IMs. These are described more fully in the following subsections of this proposal. A full list of our capex and opex projects and programmes is set out below.

Section 9, in particular subsections 9.13 to 9.17 and 9.19 to 9.23, provides a description of each project and programme. Our approach to defining projects and programmes reflects Orion's budgeting and planning processes. Our project and programme definitions are consistent with those used for our AMP and our corporate forecasts. It has been necessary to retain as much consistency between our internal reporting codes and associated budgeting and forecasting processes and the CPP project/programme grouping as possible. This is required in order to be able to provide the prescribed information which spans the current, assessment and CPP periods.

We have also prepared Project Summary documents for each project and programme. These are more detailed for the identified projects and programmes due to the IM information requirements. They are provided as supporting documentation to this proposal. Project Summary documents for the identified projects are collated into a separate appendix document (Appendix 35) which accompanies this proposal.

For the purpose of our CPP proposal we have grouped together sub projects which are related to each other and which may occur across more than one year. An example of this is our ongoing rural Rolleston project (CPP7) which involves a number of new substations and 66kV lines. For our major capex projects the expenditure information we have provided relates to current budgets and forecasts. Historical information is not relevant to the major projects included in our forecast.

We have classified ongoing programmes for network maintenance and renewals as projects spanning the entire CPP period and the current and assessment periods (FY08 to FY19). We have segregated these on the basis of the types of assets they service.

The following tables illustrate how our capex and opex is collated into separate projects and programmes for the purpose of our CPP proposal. It also shows which projects and programmes were identified projects and programmes, subject to detailed review. Appendix 20 includes a summary of expenditure (for the current, assessment and CPP regulatory periods) for each project and programme.

CPP capex projects and programmes

Capex category	Sub category	Project or programme relevant to the next period	Reference	Verifier identified projects and programmes
Major projects	Urban	North	CPP1	Yes
		Dallington	CPP2	Yes
		West	CPP3	
		Southeast	CPP4	
		South	CPP5	
		CBD	CPP6	
	Rural	Rolleston	CPP7	Yes
		Hororata/Creyke 66kV	CPP8	
		Central Plains	CPP9	
		Springston	CPP10	
		Norwood	CPP11	
		Power Factor	CPP12	
		Annat	CPP13	
		Banks Peninsula	CPP14	
		Southbridge	CPP15	
		Dunsandel	CPP16	
		Porters Heights	CPP17	
		Kimberley	CPP18	
		Alpine	CPP19	
		GFN	CPP20	
Reinforcement		Urban	CPP51	Yes
		Rural	CPP52	
Replacement		Overhead lines – subtransmission	CPP30	
		Overhead lines – 11kV and 400V	CPP31	
		Underground cables – subtransmission	CPP41	
		Underground cables – 11kV and 400V	CPP32	
		Switchgear	CPP36	Yes
		Transformers	CPP37	Yes
		Substations	CPP38	
		Pilots and protection	CPP33	Yes
		Control systems	CPP34	
		Buildings and grounds	CPP39	Yes
		Meters	CPP40	
		Load management systems	CPP35	
		Asset management systems	CPP42	
		Distribution management systems	CPP43	
Customer connection and network extension		Customer connection and network extensions	CPP53	Yes

Underground conversions		Underground conversions	CPP50	
Asset acquisitions		Asset acquisitions	CPP54	Yes
Non network assets	Land and buildings	New head office	CPP60	Yes
		Sundry land and buildings	CPP62	Yes
		Vehicles and mobile plant	CPP63	
		Information technology	CPP64	Yes
		Sundry tools, equipment, furniture and fittings	CPP65	

CPP opex projects and programmes

Opex Category	Sub Category	Project or Programme	Reference	Identified projects and programmes
Maintenance	Emergency maintenance	Overhead lines	CPP117	
		Underground cables	CPP118	Yes
		Network assets	CPP119	Yes
	Scheduled maintenance	Overhead lines – sub transmission	CPP100	
		Overhead lines – 11kV and 400V	CPP101	Yes
		Underground cables – subtransmission	CPP103	
		Underground cables – 11kV and 400V	CPP104	
		Switchgear	CPP112	Yes
		Transformers	CPP108	Yes
		Buildings, grounds and substations	CPP109	Yes
		Protection and pilots	CPP107	
		Control systems	CPP106	
		Meters	CPP110	
		Earths	CPP102	
		Generators	CPP111	
		Mapping and asset storage	CPP105	
		Load management systems	CPP121	
		Distribution management systems	CPP123	
		Contingency maintenance	CPP120	
	Non-scheduled maintenance	Overhead lines	CPP113	
		Underground cables	CPP115	
		Buildings, grounds and substations	CPP116	
		Network assets	CPP114	
Network management and operations		Infrastructure management	CPP167	Yes
General		Corporate	CPP160	Yes

management, administration and overheads	Finance	CPP161	
	Information solutions – corporate	CPP164	Yes
	Commercial and regulatory	CPP165	Yes
	Communications and engagement	CPP166	
	Property maintenance	CPP168	
	Insurance (premiums and brokerage)	CPP169	
	Earthquake (overheads and head office)	CPP170	
	Special projects	CPP171	

8.5.2 Service categories

We have defined our capex and opex plan in the context of the services we offer. Each category of services is defined in Schedule D of the CPP IM, comprising the following:

- provide and operate network infrastructure between input and off-take connection points and deliver electricity through the network
- provide load management services
- provide connection services, including changes of connection point capacity and/or reliability
- provide for rearrangement of network assets at third party request including undergrounding
- provide additional services to those listed above.

In accordance with clause 5.4.30(3) we have allocated projects or programmes to the service category most relevant to the expenditure. A full description of these service categories and their relevant service measures and targets is set out in Section 9.6.

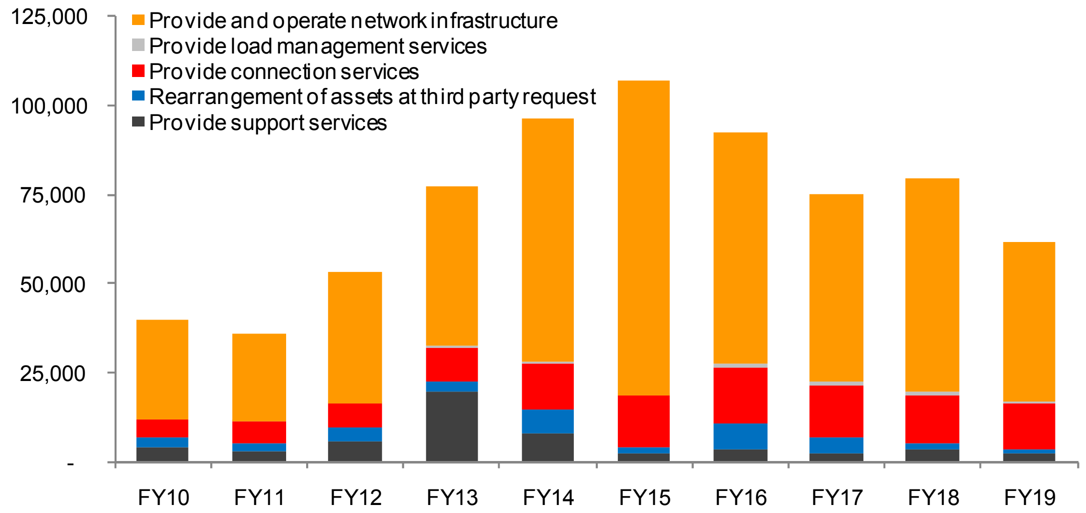
We have not allocated corporate or network management costs to service categories as these costs are not directly related to the services specified above. Together they provide the support infrastructure which enables Orion to meet all of its service obligations. In the following tables and charts we show corporate and network management costs as support services.

The following tables and charts illustrate our allocations of capex and opex to the service categories. The data for opex covers the full current (FY08 to FY12), assessment (FY13 to FY14) and CPP periods (FY15 to FY19). The data for capex excludes the first two years of the current period because we have not had access to the systems and detailed data to be able to manipulate it into this CPP specific format.

Nominal capex by service category ($000)	Current period			Assessment Period	
Service Categories	**FY10**	**FY11**	**FY12**	**FY13**	**FY14**
Provide and operate network infrastructure	27,784	24,631	36,715	44,797	68,359
Provide load management services	-	7	181	790	517
Provide connection services	5,113	6,058	6,898	9,650	12,829
Rearrangement of assets at third party request	2,588	2,475	3,627	2,300	6,570
Provide additional services	-	-	-	-	-
Provide support services	4,134	2,912	5,880	20,030	7,977
Total	**39,618**	**36,083**	**53,301**	**77,567**	**96,252**

	CPP Period				
Service Categories	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Provide and operate network infrastructure	87,870	64,358	52,161	60,315	44,984
Provide load management services	138	1,593	1,020	1,014	515
Provide connection services	14,523	15,616	14,612	13,100	12,703
Rearrangement of assets at third party request	1,768	6,862	4,460	1,758	1,096
Provide additional services	-	-	-	-	-
Provide support services	2,409	3,771	2,601	3,633	2,621
Total	**106,708**	**92,200**	**74,854**	**79,820**	**61,920**

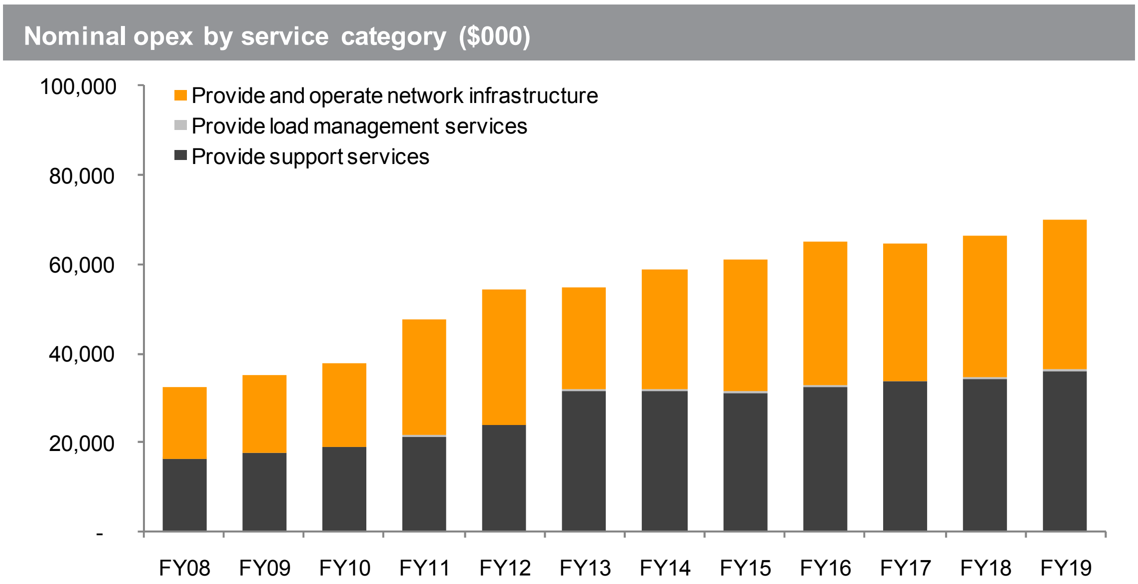
Nominal capex by service category ($000)



As illustrated above, the ‘provide and operate network infrastructure’ service category dominates our capex with the other notable service category being ‘provide connection services’. Our data in this section of the report is reported before any contributions from customers or other third parties are deducted. The large support service capex in FY13 reflects our new head office building currently being constructed.

Nominal opex by service category ($000)	Current period					Assessment Period	
Service Categories	**FY08**	**FY09**	**FY10**	**FY11**	**FY12**	**FY13**	**FY14**
Provide and operate network infrastructure	15,760	17,322	18,605	25,961	30,254	22,775	26,785
Provide load management services	180	114	152	112	89	355	244
Provide connection services	-	-	-	-	-	-	-
Rearrangement of assets at 3rd party request	-	-	-	-	-	-	-
Provide additional services	-	-	-	-	-	-	-
Provide support services	16,448	17,640	18,982	21,536	23,976	31,510	31,724
Total	**32,387**	**35,076**	**37,738**	**47,609**	**54,319**	**54,640**	**58,753**

	CPP Period				
Service Categories	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Provide and operate network infrastructure	29,624	32,453	30,925	31,798	33,293
Provide load management services	260	276	289	302	315
Provide connection services	-	-	-	-	-
Rearrangement of assets at 3rd party request	-	-	-	-	-
Provide additional services	-	-	-	-	-
Provide support services	31,321	32,512	33,671	34,320	36,244
Total	**61,205**	**65,242**	**64,884**	**66,419**	**69,852**



In terms of opex, the ‘provide and operate network infrastructure’ service is again dominant, along with support services. There is relatively little opex associated with the other service categories.

8.5.3 Expenditure categories

Expenditure is grouped into six capex and five opex categories. Projects or programmes are assigned to capex or opex categories based on the category which is most relevant for the project.

Our categories and their corresponding definitions are set out in the following table. As these differ to the standard categories included in Schedule D of the CPP IM, we have also shown how our categories can be mapped to the IM categories.

Categorisation of capex

Capex category	Definition	Equivalent IM category
Major projects	Capex (mainly 66kV or 33kV sub transmission including zone substations) principally incurred in implementing a large step change in capacity to meet demand on the network assets, or the maintaining of or improvement of security of supply, reliability or service standards; safety of the network for consumers, employees and the public; or activities to meet new or enhanced legislative requirements; or achieve enhancements, relating to the environment	System growth *plus* reliability, safety and environment capex
Reinforcement	Routine capex (mainly 11kV) principally incurred in maintaining security of supply, reliability or service standards on the network, as a result of changes in demand	System growth *plus* reliability, safety and environment capex
Replacement	Capex predominantly associated with the progressive physical deterioration of the condition of network assets or their immediate surrounds; or expenditure arising as a result of the obsolescence of network assets	Asset replacement and renewal
Customer connection / network extension	Capex predominantly associated with the establishment of new connection points of consumers to the network, or alterations to existing connection points where the expenditure relates to connection assets and/or parts of the network and which may be recoverable or partially recoverable from the customer	Customer connection
Underground conversions	Capex principally incurred in relocating assets from overhead to underground where the relocation does not result in the assets having service potential materially different to their service potential in their original location	Asset relocations
Asset acquisitions	The purchase of 66kV spur assets from Transpower for the purpose of integrating them with Orion's existing and developing sub transmission network	n/a
Non-system fixed assets	Capex incurred in relation to assets not directly related to the network used in the supply of electricity distribution services, including in relation to information and technology systems;	Non-system fixed assets

	asset management systems; office buildings, depots and workshops; office furniture and equipment; motor vehicles; and tools, plant, and machinery	

Categorisation of opex

Opex category	Definition	Equivalent IM category
Emergency maintenance	Opex which is principally incurred in responding to an unplanned instantaneous event that impairs the normal operation of network assets	Fault and emergency maintenance
Scheduled maintenance	Opex that is predominantly associated with planned work; routine inspection and testing; site maintenance; and vegetation management activities	Routine and preventative maintenance; *plus* refurbishment and renewal maintenance
Non-scheduled maintenance	Opex that is predominantly associated with unplanned work and includes fault rectification work that is undertaken at a time or date subsequent to any initial fault response restoration activities	
Network management and operations	Opex related to the management and operation of the network including system operations; system studies; planning; design; network record keeping; contract management and standards and manuals	System management and operations
General management, administration and overheads	Opex that is principally incurred on administration or which is not directly incurred in the physical operation and maintenance of the network, including expenditure on accounting; corporate management; finance; human resources; corporate information technology; insurance paid to an insurer; legal; occupational health and safety; corporate procurement; property; and regulation	General management, administration and overheads

Our capex and opex categories are consistent with those we use for network asset management planning. The use of our own categories is permitted under clause 5.4.31 of the CPP IM.

Subclause (1)(b)(ii) of 5.4.31 requires capex and opex for the next period to be presented in accordance with the CPP IM categories. This has required us to re-specify our planned capex and opex using expenditure categories which differ to those which we use to plan and forecast. The table above outlines, as best we are able to, the differences between the IM expenditure categories and our own. Many of our categories are aligned on a one for one basis. However, this is not possible for the categories listed below. In order to meet this compliance obligation we have relied on clause 5.4.30(2)(a) of the CPP IM which indicates that we should select the capex category or opex category that is most relevant based on the nature of the expenditure. Thus our allocation to IM categories is as follows:

- scheduled maintenance opex is allocated to routine and preventative maintenance
- non scheduled maintenance opex is allocated to routine and preventative maintenance
- all major project capex is allocated to system growth capex, with the exception of CPP20 (GFN) which is allocated to reliability, safety and environment capex
- all asset acquisitions are allocated to system growth capex
- both reinforcement capex programmes are allocated to system growth capex.

We note that we have been constrained in our ability to provide historical capex for FY08 and FY09 of the current period in the same categories of expenditure as used for our forecasts. This is because some of our financial systems and financial records were damaged during the 22 February 2011 earthquake.

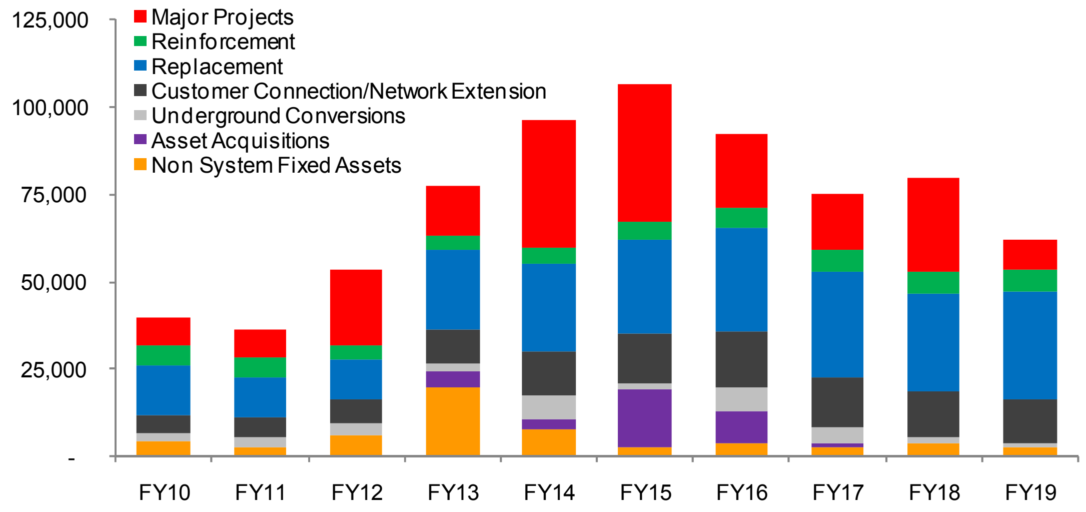
Although we have accurate information about the value of commissioned assets by asset type (which is required in order to establish our RAB value) we are not able to disaggregate our historical capex information for FY08 and FY09 at the project/programme level between the types of expenditure – for example to major projects, replacement or other capex categories.

The following charts illustrate how our capex and opex is comprised on an expenditure category basis, using our categories of capex and opex.

Nominal capex by expenditure category ($000)	Current Period			Assessment Period	
Expenditure Categories	**FY10**	**FY11**	**FY12**	**FY13**	**FY14**
Major Projects	8,119	7,855	21,236	14,346	36,329
Reinforcement	5,304	5,318	4,480	4,150	4,939
Replacement	14,361	11,465	11,181	22,903	24,907
Customer Connection/Network Extension	5,113	6,058	6,898	9,650	12,829
Underground Conversions	2,588	2,475	3,627	2,300	6,570
Asset Acquisitions	-	-	-	4,188	2,700
Non System Fixed Assets	4,134	2,912	5,880	20,030	7,977
Total	**39,618**	**36,083**	**53,301**	**77,567**	**96,252**

	CPP Period				
Expenditure Categories	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Major Projects	39,442	21,068	15,623	26,961	8,354
Reinforcement	5,348	5,725	6,135	6,310	6,544
Replacement	26,433	29,739	30,225	28,058	30,600
Customer Connection/Network Extension	14,523	15,616	14,612	13,100	12,703
Underground Conversions	1,768	6,862	4,460	1,758	1,096
Asset Acquisitions	16,784	9,419	1,198	-	-
Non System Fixed Assets	2,409	3,771	2,601	3,633	2,621
Total	**106,708**	**92,200**	**74,854**	**79,820**	**61,920**

Nominal capex by expenditure category ($000)



Network based capex dominates our overall capex. Non network capex represented by non system fixed assets, forms a very small component of total capex. This is consistent with the nature of our business which is to build and replace the network infrastructure required to deliver electricity to consumers.

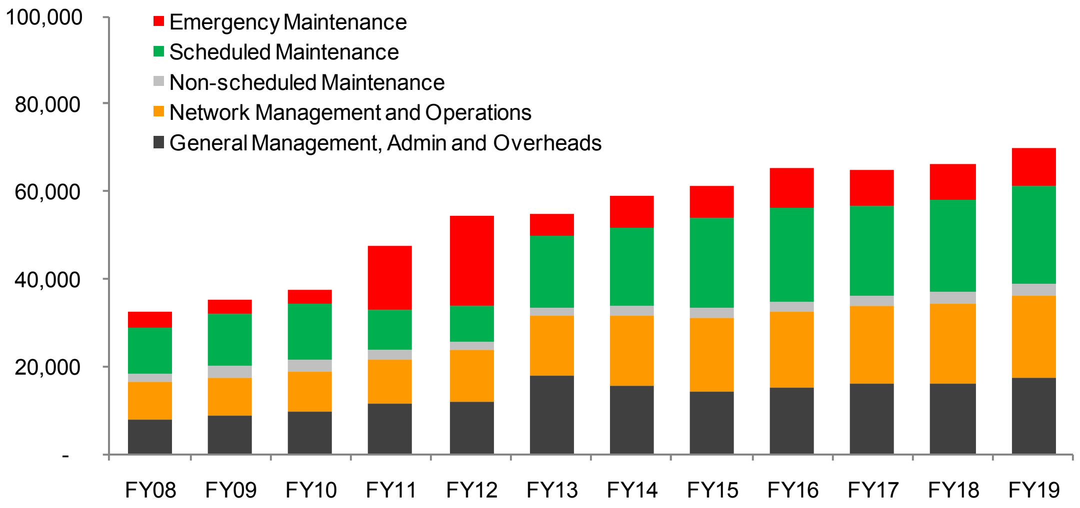
Major project and asset replacement capex comprise the majority of our capex forecast. This is consistent with historical trends.

Customer connection capex is more evident in the assessment and CPP periods, than in the current period. This trend is expected, due to the relocation and rebuilding activities throughout Christchurch and wider Canterbury, as a consequence of the earthquakes. As noted earlier our spur asset acquisitions and new head office non system capex are also notable components of our capex forecasts.

Nominal opex by expenditure category ($000)	Current Period					Assessment Period	
Expenditure Categories	**FY08**	**FY09**	**FY10**	**FY11**	**FY12**	**FY13**	**FY14**
Emergency Maintenance	3,608	3,122	3,495	14,534	20,603	4,925	6,903
Scheduled Maintenance	10,443	11,887	12,577	9,045	7,910	16,210	18,009
Non-scheduled Maintenance	1,888	2,426	2,684	2,494	1,829	1,995	2,118
Network Management and Operations	8,410	8,712	9,498	10,122	11,795	13,681	15,989
General Management, Admin and Overheads	8,038	8,928	9,484	11,414	12,181	17,829	15,736
Total	**32,387**	**35,076**	**37,738**	**47,609**	**54,319**	**54,640**	**58,753**

	CPP Period				
Expenditure Categories	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Emergency Maintenance	7,311	9,197	8,092	8,443	8,810
Scheduled Maintenance	20,323	21,138	20,619	21,042	22,065
Non-scheduled Maintenance	2,250	2,394	2,502	2,614	2,732
Network Management and Operations	16,916	17,487	17,706	18,166	18,661
General Management, Admin and Overheads	14,406	15,025	15,965	16,154	17,584
Total	**61,205**	**65,242**	**64,884**	**66,419**	**69,852**

Nominal opex by expenditure category ($000)



Our opex on network assets is dominated by scheduled maintenance. The exceptions are FY11 and FY12 which show our large emergency maintenance expenditure following the earthquakes.

We have made no allowance in our expenditure forecast for further events of a catastrophic nature.

Our scheduled maintenance forecast increases in FY13 and continues to be higher than what we had spent pre-earthquakes. This reflects two key factors: the need to restore the condition of our damaged network assets; and the cost pressures we face in our local contract market due to the accelerating construction activity in Canterbury.

Our opex also includes significant expenditure in network and corporate support services which are predominantly office based. This is represented by the network management and operations and general management, corporate and overheads opex categories.

The following tables show our capex and opex reallocated into the IM categories consistent with the requirements of sub-clause (1)(b)(ii) of 5.4.31.

Nominal capex by IM expenditure category ($000)	Current Period			Assessment Period	
IM Expenditure Categories	**FY10**	**FY11**	**FY12**	**FY13**	**FY14**
Customer connection	5,113	6,058	6,898	9,650	12,829
System growth	13,423	13,173	25,716	21,828	42,749
Reliability, safety and environment	-	-	-	856	1,219
Asset replacement and renewal	14,361	11,465	11,181	22,903	24,907
Asset relocations	2,588	2,475	3,627	2,300	6,570
Non-system fixed assets	4,134	2,912	5,880	20,030	7,977
Total	**39,618**	**36,083**	**53,301**	**77,567**	**96,252**

	CPP Period				
IM Expenditure Categories	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Customer connection	14,523	15,616	14,612	13,100	12,703
System growth	61,574	36,213	22,955	33,271	14,899
Reliability, safety and environment	-	-	-	-	-
Asset replacement and renewal	26,433	29,739	30,225	28,058	30,600
Asset relocations	1,768	6,862	4,460	1,758	1,096
Non-system fixed assets	2,409	3,771	2,601	3,633	2,621
Total	**106,708**	**92,200**	**74,854**	**79,820**	**61,920**

Nominal opex by IM expenditure category ($000)	Current Period					Assessment Period	
IM Expenditure Categories	**FY08**	**FY09**	**FY10**	**FY11**	**FY12**	**FY13**	**FY14**
General management, admin and overheads	8,038	8,928	9,484	11,414	12,181	17,829	15,736
System management and operations	8,410	8,712	9,498	10,122	11,795	13,681	15,989
Routine and preventative maintenance	12,331	14,314	15,261	11,539	9,739	18,205	20,126
Refurbishment and renewal maintenance	-	-	-	-	-	-	-
Fault and emergency maintenance	3,608	3,122	3,495	14,534	20,603	4,925	6,903
Other opex	-	-	-	-	-	-	-
Total	**32,387**	**35,076**	**37,738**	**47,609**	**54,319**	**54,640**	**58,753**

	CPP Period				
IM Expenditure Categories	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
General management, admin and overheads	14,406	15,025	15,965	16,154	17,584
System management and operations	16,916	17,487	17,706	18,166	18,661
Routine and preventative maintenance	22,573	23,532	23,121	23,656	24,798
Refurbishment and renewal maintenance	-	-	-	-	-
Fault and emergency maintenance	7,311	9,197	8,092	8,443	8,810
Other opex	-	-	-	-	-
Total	**61,205**	**65,242**	**64,884**	**66,419**	**69,852**

8.5.4 Asset categories

Our system related expenditure (both opex and capex) is allocated to asset categories. These asset categories are specified in Schedule D of the IMs. Within each asset category expenditure is further disaggregated into asset types, although these are not specified in the IMs. Our expenditure information is presented as follows:

Allocating capex and opex to asset categories and asset types

Asset category	Asset types for capex	Asset types for opex
Sub-transmission network including power transformers	66kV lines 66kV cables 33kV lines 33kV cables Pilot and communications circuits Zone substation land Site development and buildings Power transformers Protection Outdoor structures DC supplies, batteries and inverters Other items	66kV lines 66kV cables 33kV lines 33kV cables Pilot and communications circuits Zone substation land, site development and buildings Power transformers Protection Other items
Distribution network including distribution transformers	11kV lines 11kV cables Distribution transformers Distribution substations including land	11kV lines 11kV cables Distribution transformers Distribution substations including land
Switchgear	66kV / 33kV surge diverters and airbreak isolators 66kV / 33kV / 11kV indoor circuit breakers and switchgear 66kV / 33kV / 11kV outdoor circuit breakers and switchgear 11kV disconnectors and drop out fuses 11kV voltage regulators	Distribution switchgear
Low voltage distribution network	LV lines LV cables Link pillars and customer connections	LV lines LV cables Link pillars and customer connections
Supporting or secondary systems	Ripple injection plant SCADA Communications equipment Metering systems Power factor correction plant Mobile substations and generators Easements Load management systems Asset management systems Distribution management systems	Load management SCADA and control Communication equipment Metering systems Generators

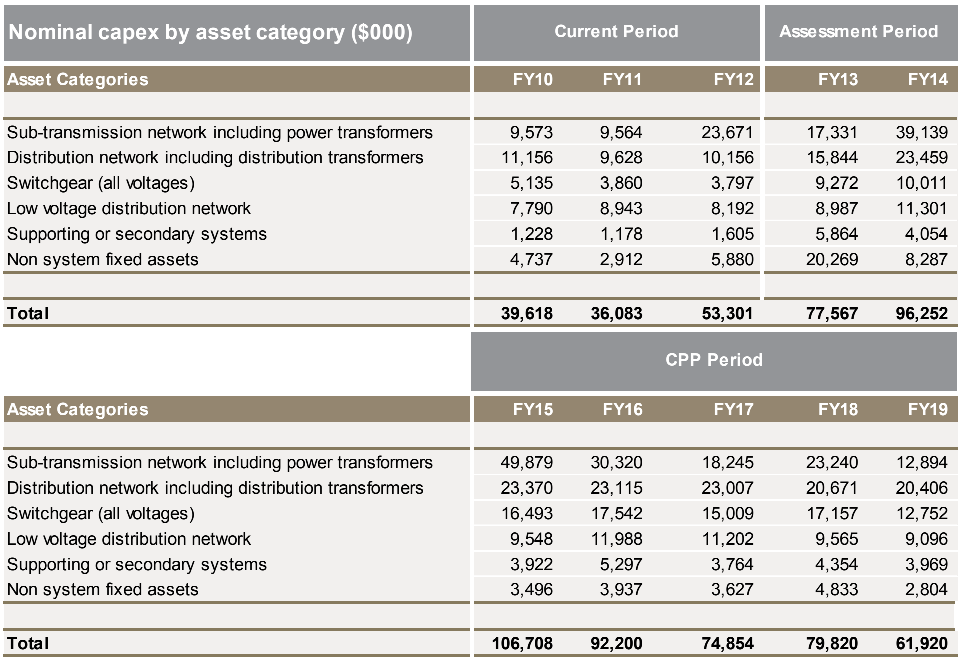
Non system fixed assets	Information and technology systems Non network buildings Non network land Tools, equipment furniture and fittings Motor vehicles and mobile plant

Note: Non asset related opex (ie: opex not assigned to an asset category) includes:

- Network management and operations opex
- General management, administration and overheads opex

There is more disaggregation into asset types in our capex information. This enables future capex project costs to be estimated by individual asset components. Our maintenance opex activities do not require the same degree of disaggregation. The capex asset type categories must also be consistent with the depreciation requirements of the CPP IM. An explanation of our depreciation calculations and assumptions regarding asset types is set out in Section 7.5.3 and Appendix 15.

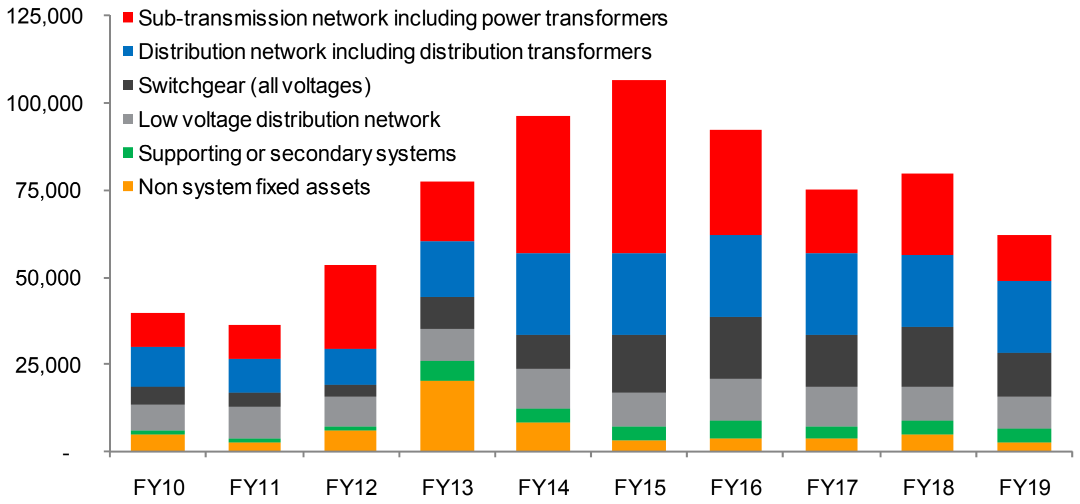
Asset categories and types apply at the project and programme level. The following tables and charts illustrate how the capex and opex is made up on an asset category basis. Further detail regarding our asset types can be found in the project and programme schedules which accompany this proposal. Note that corporate and network support opex is excluded from these allocations.



Nominal capex by asset category ($000)	Current Period			Assessment Period	
Asset Categories	**FY10**	**FY11**	**FY12**	**FY13**	**FY14**
Sub-transmission network including power transformers	9,573	9,564	23,671	17,331	39,139
Distribution network including distribution transformers	11,156	9,628	10,156	15,844	23,459
Switchgear (all voltages)	5,135	3,860	3,797	9,272	10,011
Low voltage distribution network	7,790	8,943	8,192	8,987	11,301
Supporting or secondary systems	1,228	1,178	1,605	5,864	4,054
Non system fixed assets	4,737	2,912	5,880	20,269	8,287
Total	**39,618**	**36,083**	**53,301**	**77,567**	**96,252**

	CPP Period				
Asset Categories	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Sub-transmission network including power transformers	49,879	30,320	18,245	23,240	12,894
Distribution network including distribution transformers	23,370	23,115	23,007	20,671	20,406
Switchgear (all voltages)	16,493	17,542	15,009	17,157	12,752
Low voltage distribution network	9,548	11,988	11,202	9,565	9,096
Supporting or secondary systems	3,922	5,297	3,764	4,354	3,969
Non system fixed assets	3,496	3,937	3,627	4,833	2,804
Total	**106,708**	**92,200**	**74,854**	**79,820**	**61,920**

Nominal capex by asset category ($000)

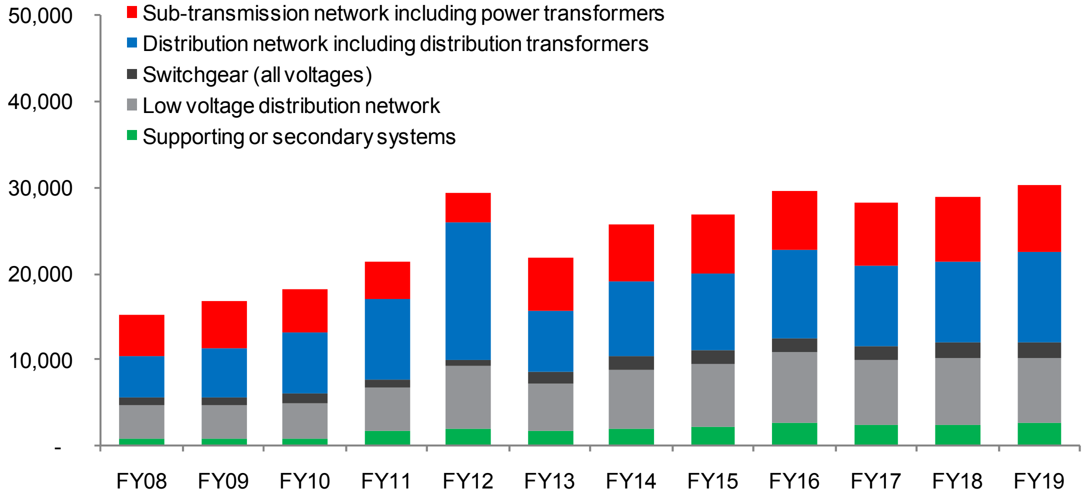


A significant portion of our capex is associated with sub transmission assets, and in decreasing importance, our distribution network and switchgear. Our spur asset purchases predominantly involve sub transmission assets. Our urban and rural sub transmission networks will undergo significant change during the next few years as we invest to implement out system security standards, rebuild resiliency into the eastern suburbs and accommodate growth in the rural area and increased demand in the north of our urban network. Our distribution and switchgear expenditure largely reflects planned replacements and network reinforcement required to maintain network performance, although the sub transmission projects also require significant investment in new switchgear.

Nominal network opex by asset category ($000)	Current period					Assessment Period	
Asset Categories	**FY08**	**FY09**	**FY10**	**FY11**	**FY12**	**FY13**	**FY14**
Sub-transmission network including power transformers	4,745	5,354	5,017	4,487	3,474	6,185	6,662
Distribution network including distribution transformers	4,913	5,710	7,114	9,293	15,924	7,020	8,504
Switchgear (all voltages)	888	1,011	1,074	832	735	1,412	1,592
Low voltage distribution network	3,912	3,804	4,039	5,125	7,251	5,445	6,853
Supporting or secondary systems	788	912	899	1,685	2,072	1,823	2,089
Total	**15,247**	**16,791**	**18,142**	**21,422**	**29,457**	**21,885**	**25,700**

	CPP Period				
Asset Categories	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Sub-transmission network including power transformers	6,860	6,952	7,152	7,462	7,799
Distribution network including distribution transformers	9,027	10,272	9,423	9,455	10,553
Switchgear (all voltages)	1,625	1,597	1,631	1,705	1,782
Low voltage distribution network	7,221	8,254	7,497	7,835	7,572
Supporting or secondary systems	2,220	2,633	2,419	2,476	2,656
Total	**26,953**	**29,708**	**28,122**	**28,932**	**30,362**

Nominal network opex by asset category ($000)



System related opex (maintenance) is targeted more towards the distribution and low voltage parts of our network. These lower parts of our network contain large numbers of individual assets which must be inspected and maintained. The asset category spend is relatively constant over the next period. The earthquake impacts are evident in the abnormally high maintenance required on the distribution and low voltage network in FY11 and FY12.

8.5.5 Project costs by source

We have set out our expenditure programme by source; the parties that have or are expected to undertake the capex and opex. This requirement applies to the network components of expenditure (ie: it excludes non system fixed asset capex and network management and operations and general management, administration and overheads opex).

Some work is undertaken by Orion employees and some is undertaken by other contractors. Where contractors are involved, we have identified that component which is undertaken by related parties; in this instance Connetics Limited a wholly owned subsidiary of Orion. For completeness the following charts and tables show network management and corporate opex as undertaken by Orion.

All network maintenance and construction work (where practicable and appropriate) is competitively tendered to selected contractors on a conforming tender/lowest price basis. Tenders and contract works are processed and managed by our infrastructure management group.

The scope of out-sourced works to consultants and contractors can be summarised as follows:

Our out-sourcing	
Consultants	**Contractors**
Expert advice	Emergency response services
Detailed design	Spares and major plant services
	Specialist asset inspection and non-invasive/non-destruction testing
	Maintenance of existing network infrastructure
	Installation and replacement of new or existing network infrastructure

Our tender work is bid for by a number of contractors, including Connetics. Accordingly it is not possible for us to forecast which proportion of external work will be undertaken by Connetics and which proportion will be undertaken by contractors which are not related to Orion. For this reason we have included a “to be tendered” category in the source data for the next period.

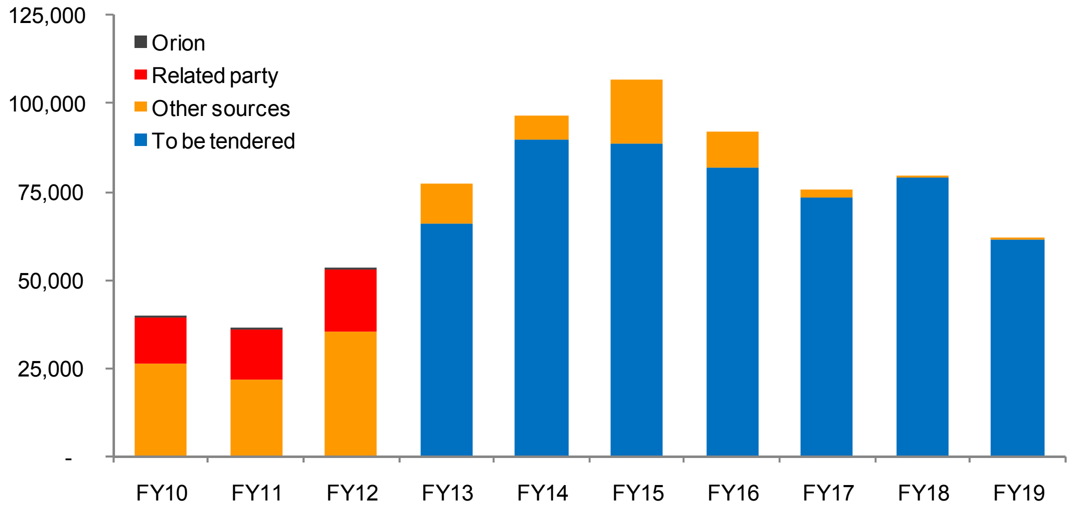
However, our emergency maintenance contracts have recently been re-tendered. One of these contracts has been assigned to Connetics. Accordingly we have estimated the proportion of emergency maintenance work included in our forecast (to FY17 which is when the contract is to expire) which we expect will be assigned to Connetics under the terms of that contract. This is shown as related party opex in the following tables and charts, for FY13 – FY17.

Our processes for tendering work and the nature of the contracts we have with Connetics are explained in Sections 9.11.2 and 9.25. Our project descriptions provided in Sections 9.13 to 9.17 and 9.19 to 9.23, supported by our Project Summary Documents, explain the deliverability of each project and programme, with reference to the project source.

The following tables and charts show our capex and opex plan by project source.

Nominal capex by project source ($000)	Current Period			Assessment Period		CPP Period				
Sources	**FY10**	**FY11**	**FY12**	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Orion	78	50	106	-	-	-	-	-	-	-
Related party	13,231	14,393	17,774	-	-	-	-	-	-	-
Other sources	26,309	21,641	35,420	11,608	6,224	18,078	10,164	2,251	970	697
To be tendered	-	-	-	65,959	90,028	88,630	82,036	72,603	78,850	61,223
Total	**39,618**	**36,083**	**53,301**	**77,567**	**96,252**	**106,708**	**92,200**	**74,854**	**79,820**	**61,920**

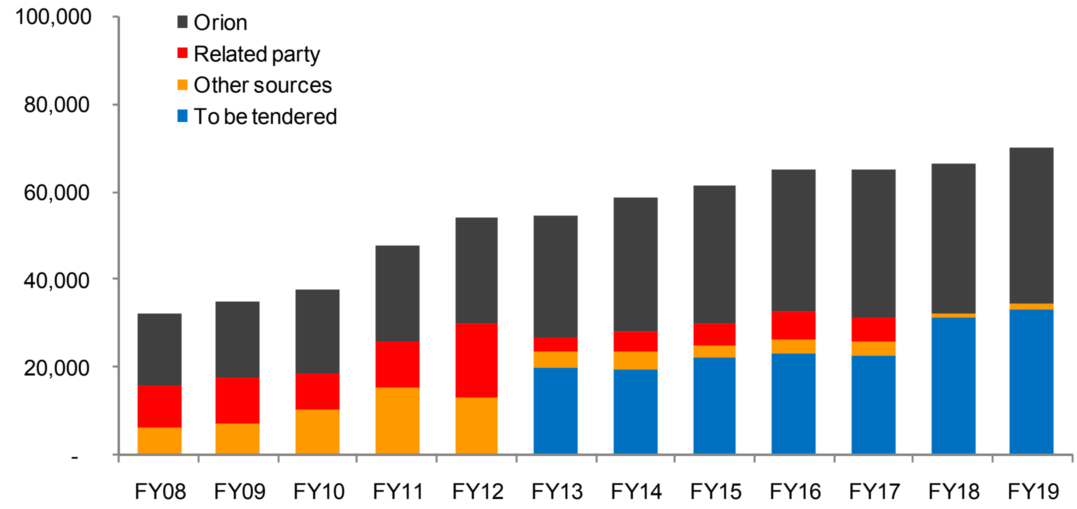
Nominal capex by project source ($000)



Our network capex has been, and continues to be, undertaken by a range of contractors. In FY10 to FY12, approximately 35% of our network capex was completed by Connetics, awarded by competitive tender. Our CPP forecasts include spur asset acquisitions which have been designated as 'other sources'. The remainder of our capex is forecast to be tendered.

Nominal opex by project source ($000)	Current period					Assessment Period		CPP Period				
Sources	**FY08**	**FY09**	**FY10**	**FY11**	**FY12**	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Orion	16,370	17,306	19,260	21,745	24,178	27,718	30,575	31,321	32,508	33,663	34,307	35,317
Related party	9,611	10,417	8,172	10,334	15,124	3,044	4,330	4,595	6,024	5,100	-	-
Other sources	6,407	7,353	10,306	15,531	15,017	3,881	4,118	3,248	3,725	3,562	588	1,516
To be tendered	-	-	-	-	-	19,997	19,731	22,041	22,985	22,560	31,524	33,019
Total	**32,387**	**35,076**	**37,738**	**47,609**	**54,319**	**54,640**	**58,753**	**61,205**	**65,242**	**64,884**	**66,419**	**69,852**

Nominal opex by project source ($000)



As illustrated above Orion is responsible for approximately just over half of our expected opex, which reflects our corporate and infrastructure management support services. Although we use consultants from time to time to assist us, this is not a material component of this expenditure category and we have not sought to explicitly forecast this component of our support opex.

Of our total maintenance, Connetics undertook approximately 45% of the work undertaken in FY10 to FY12. This was inflated in FY12 where emergency contract work was greater than normal due to the high number of earthquake related events, especially the repair of over 800 11kV underground cable faults. In FY10 and FY11, Connetics work comprised 42% of total maintenance. In FY12 Connetics undertook approximately 50% of our total maintenance work. This also reflected the fact that we were forced to defer some planned maintenance, which typically would have been offered for tender, in order to concentrate on our immediate earthquake response.

In FY12 Connetics managed a number of subcontractors (many from out of town) in its earthquake emergency response work. This enabled key Orion managers to better concentrate on deciding on and allocating network restoration, repair and recovery work in the most efficient and effective manner.

8.5.6 Project costs by input cost item

We have identified key input costs for each project and programme in the CPP regulatory period and the final year of the assessment period. This has helped us to forecast our costs. Our process for forecasting the costs for each project and programme is set out in the individual Project Summary Documents and the supporting explanatory policy documents NW70.50.03 and NW70.60.13. Further explanation is provided in Sections 9.13.10, 9.20.6 and 9.26 which explain our overall approach to deriving our capex and opex forecasts and our cost escalation approach.

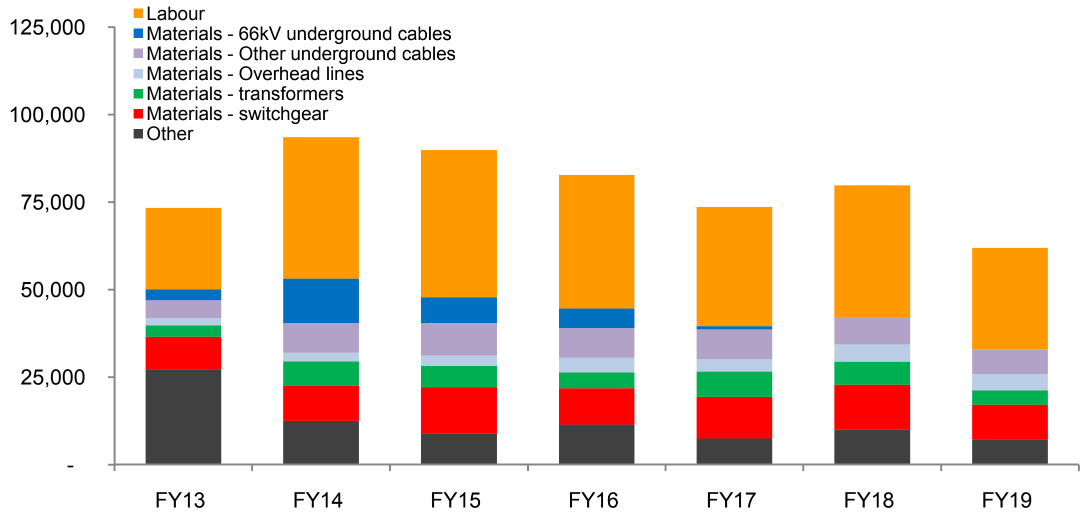
We have grouped each capex project into three input categories: labour, materials and other. Within the materials category, we have also identified cables/conductor, transformers and switchgear sub categories. For opex we have retained the labour, materials and other categories, but have not applied any subcategories within materials. This categorisation has helped us forecast future costs of each project/programme because we have been able to consider how the costs of each of these categories are likely to change over the forecast period.

Our methodology and assumptions to derive input cost escalators are set out in Section 9.26 along with the escalators we have applied.

The following table and chart exclude the value of our spur asset acquisitions because the values for these assets included our capex forecast are determined by Transpower's regulatory asset base values, not input component costs.

Nominal capex by input category ($000)	Assessment Period		CPP Period				
Input category	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Labour	23,339	40,370	42,075	38,139	34,065	37,843	28,920
Materials - 66kV underground cables	3,041	12,710	7,384	5,599	930	-	-
Materials - Other underground cables	5,080	8,416	9,215	8,452	8,521	7,595	7,100
Materials - Overhead lines	2,108	2,512	3,004	4,200	3,517	4,957	4,642
Materials - transformers	3,247	6,963	6,058	4,533	7,224	6,545	4,096
Materials - switchgear	9,289	10,035	13,343	10,373	11,896	12,914	9,876
Other	27,274	12,544	8,845	11,485	7,504	9,965	7,288
Total	**73,379**	**93,552**	**89,923**	**82,781**	**73,656**	**79,820**	**61,920**

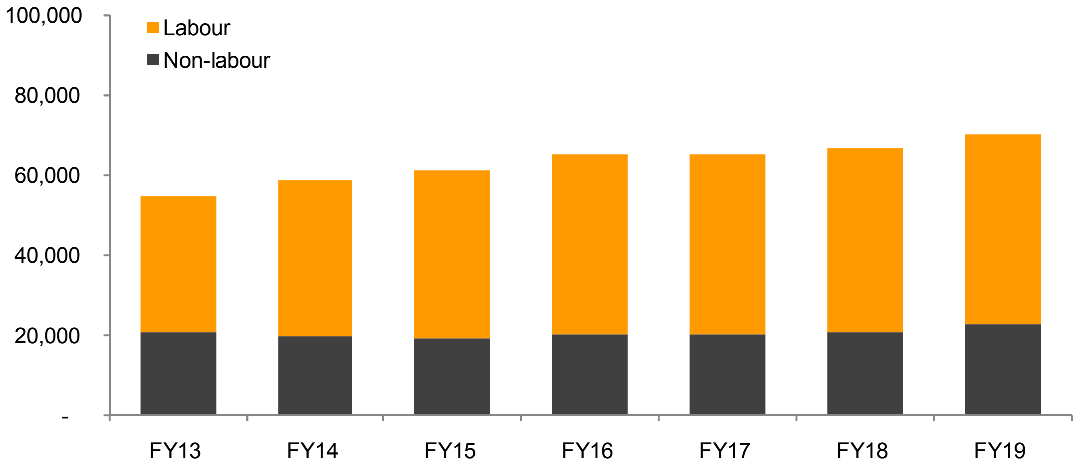
Nominal capex by input category ($000)



As illustrated above, our capex forecast includes large proportions of labour costs. These comprise approximately 45% of our annual capex spend. Underground cables and overhead conductors are also significant, particularly in FY14 and FY15, reflecting our sub transmission projects as well as the forecast cable replacement and network reinforcement. Our forecast transformer spend in these years is also consistent with this expenditure programme.

Nominal opex by input category ($000)	Assessment Period		CPP Period				
Input category	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Labour	34,115	39,106	42,117	45,018	44,603	45,645	47,385
Non-labour	20,525	19,647	19,089	20,224	20,282	20,774	22,467
Total	**54,640**	**58,753**	**61,205**	**65,242**	**64,884**	**66,419**	**69,852**

Nominal opex by input category ($000)



As illustrated above labour is the predominant input in network opex at around 67% each year. This is consistent with the manual nature of maintenance work and the support opex which is primarily comprised of employee related expenditure.

8.6 Qualitative and quantitative information

The information presented in this Section 8 provides an overview and introduction to our expenditure forecasts and how these have been collated and presented in this proposal. In Section 9 we set out a full explanation of our expenditure forecasts and relevant supporting information, for every project and programme in our expenditure plan.

8.7 Appendices and supporting documents and spreadsheets

Section 8 – Appendices	
Appendix	**Title**
5	Modifications to Schedule E templates
15	Depreciation categories

20	Project and programme expenditure summary
36	Project Summary documents for Identified Projects

Section 8 – Supporting documentation

Description
Project Summary Documents for each CPP project and programme
NW.70.50.03 Project budget forecasting process
NW.70.60.13 Project budgeting forecasting process document

Section 8 - Accompanying Schedule E spreadsheets

Name	Description
Table 1 – Top 5.xlsx	Schedule E Table 1
Table 2 – Capex summary.xlsx	Schedule E Table 2
Table 3 – Opex summary.xlsx	Schedule E Table 3
Table 4 – Major projects (nom).xlsx	Schedule E Table 4
Table 4 – Other capex (nom).xlsx	Schedule E Table 4
Table 4 – Replacement capex (nom).xlsx	Schedule E Table 4
Table 5 – Network opex (nom).xlsx	Schedule E Table 5
Table 6a – Non-network opex (nom).xlsx	Schedule E Table 6
Table 6b – Non-network capex (nom).xlsx	Schedule E Table 6
Table 7 – Unit cost escalators (capex).xlsx	Schedule E Table 7
Table 7 – Unit cost escalators (opex).xlsx	Schedule E Table 7
Tables 8 & 9 – Cost allocation.xlsx	Schedule E Tables 8 and 9

9 Capex/opex/demand qualitative information

9 Capex/opex/demand qualitative information

IM 5.4.28 and Schedule D

9.1 Introduction and summary

IM D2

9.1.1 Introduction

Clause 5.4.28 of the CPP IM refers to capex, opex and demand qualitative information. It specifies that all information set out in Schedule D of the IMs must be included in a CPP proposal. Schedule D2 (1)(a) specifies that this information must be collated together in a section of the CPP proposal entitled “Capex/Opex/Demand Qualitative Information”. This section of our CPP proposal meets these requirements.

9.1.2 Summary

This section sets out the qualitative information which supports our quantitative capex and opex forecasts, summarised in Section 8. It provides information about the policies and procedures which support our capex and opex plan, consistent with the core electricity lines services that we provide. In addition it describes how we determine our services measures and targets, and how these are inherent in determining our expenditure plans.

Forecasts of consumer demand necessary for us to undertake our capex and opex planning are also presented. These align with our revenue quantity estimates included in Section 7.

Asset management planning

Our asset management planning processes are well documented in our annual AMP. The information presented in this section of our CPP proposal draws directly from our AMP, in particular in respect of our:

- linkages between our AMP and our corporate plans
- risk management processes, assessments and mitigation
- life cycle asset management planning approach
- network design and planning standards
- demand projections and customer service targets
- information management and performance assessment processes.

Deliverability

As presented in Section 8, we are forecasting a substantial capex and opex programme, necessary to restore our network’s resiliency and reliability in order to meet our consumers’ expectations. We are confident that we can deliver the capex and opex programme we have included in this proposal. We use a range of competent contracting resources on our network. Our ability to respond so quickly to the unforeseen demands resulting from the earthquakes and re-prioritise our projects and programmes accordingly demonstrates the flexibility that we have available to us in our market. Notwithstanding the resources available, we apply project prioritisation assessments when scheduling our planned works.

Our use of a number of competent contractors for field work is a core component of this deliverability objective. We have also increased and are planning further increases to our office based resources to provide the necessary planning, operations and contract management support for these projects.

Forecasting uncertainty

In applying for a CPP we are required to provide detailed forecasts for a seven year period (a two year assessment period and a five year regulatory period). Once our CPP proposal is submitted, and the Commission has completed its assessment, we are unable to modify our forecasts. This differs to our usual AMP planning process where we update our forecasts at least annually on the basis of further information and analysis.

Under normal circumstances, we would expect to be able to adequately manage forecasting uncertainty within a regulatory period. Indeed the five year DPP price path and quality standards require us to do so. However, we are not currently operating under normal circumstances and new information is constantly emerging about the condition of our assets, the future needs of our consumers, our input costs and the wider development of the Canterbury region.

We have collated all of the information we can reasonably acquire, and used our expertise and judgement to prepare the forecasts on which this CPP proposal is based. We anticipate however that information will emerge subsequent to submitting this proposal which, if incorporated into our thinking, would cause us to modify our views. This is the nature of the process however, and as we are constrained by the two year catastrophic event application window, we have proceeded with this application in good faith. It is appropriate to consider the challenges which face us in committing to a long term plan during a period of unprecedented uncertainty.

Project and programme information

In accordance with the requirements of Schedule D, we have set out information for each category of expenditure, and more detailed information for identified projects and programmes, which addresses:

- aims and objective
- relevant policies, standards and supporting reports
- deliverability and prioritisation
- costing methods
- other assumptions and basis for forecasts
- linkages to service measures and targets
- contingency allowances (where relevant)
- other explanatory background and information.

9.1.3 Structure of Section 9

The remainder of this section is structured as follows:

- Section 9.2 describes where the information set out in Schedule D may be found in this proposal, the completeness of that information and consistency with other Part 4 requirements
- Section 9.3 describes the qualitative information relied upon in meeting the requirements of Schedule D
- Section 9.4 describes Orion's asset management planning
- Sections 9.5 to 9.10 describe in turn each key step in our asset management planning process: asset management drivers, service levels, demand forecasts, lifecycle planning, risk management and performance monitoring
- Section 9.11 describes our approach to establishing our capex and opex forecasts
- Section 9.12 introduces our capital expenditure proposal
- Section 9.13 describes of our major capex projects
- Section 9.14 describes our reinforcement capex programmes
- Section 9.15 describes our replacement capex programmes
- Section 9.16 describes our other network capex projects and programmes
- Section 9.17 describes our non network capex
- Section 9.18 introduces our operating expenditure proposal
- Section 9.19 describes our emergency maintenance programmes
- Section 9.20 describes our scheduled maintenance programmes
- Section 9.21 describes our non-scheduled maintenance programmes
- Section 9.22 describes out network management and operations opex
- Section 9.23 describes our general management, administration and overheads opex including the insurance costs included in our opex forecast
- Section 9.24 describes our approach to controllable opex
- Section 9.25 includes the prescribed information pertaining to related parties
- Section 9.26 sets out our approach to cost escalation
- Section 9.27 lists the relevant appendices and supporting documents for this section.

9.2 Information provided

IM D2(1)

9.2.1 Summary of Schedule D information

In accordance with Schedule D2(1)(b), the following table sets out where, in this section, we have provided the information required under each clause of Schedule D.

In accordance with Schedule D2(1)(b) we have also provided references to separate documents we have referred to in responding to these information requirements. Some of these additional documents have been appended to our proposal. Where this is the case we have noted the appropriate appendix reference.

Information provided in accordance with CPP IM Schedule D

Schedule D Reference	Information Requirement	CPP Proposal Reference and Omissions	Supporting Documents
D3 Qualitative Information	(1) policies relied upon and supporting rationale	Appendix 21	NW70.50.03 lists all policies relied upon. These are all available as supporting documentation to this CPP Proposal.
	(2) consultants reports relied upon	Appendix 22	These reports are available as supporting documentation to this CPP proposal.
	(3) references to AMP where relied upon	Appendix 23	Our 2012 AMP is available as supporting documentation. Our 2013 AMP will be available in March 2013.
D4 Categorisation of Services	a) description of services	9.6.1 – 9.6.4	• Delivery Services Agreement • Connections and extensions policy (NW70.00.45) • System security standards (Section 6.2.7) • Asset management policy (NW70.00.46) • Health and safety policies (OR00.00.01 and 02) • Infrastructure management policies (refer NW70.50.03 – 9.21) • Network operation policies, refer NW70.50.03 – 9.3.1 (management), 9.3.2 (operating standards), 9.3.3 (operating procedures) and 9.3.4 (operator instructions) • Network code (NW70.00.05) • Health and safety management and safety management system manuals (NW70.00.16 and NW70.00.21) • Network operation policies and procedures (including Minimum Safe Approach Distances (NW21.07.04) and Incident/Accident recording , reporting and investigation procedures (NW00.20.02 and NW26.10.01) • Hazard identification policies (refer NW 70.50.03 – Section 9.4.2) • Contract management policies (including NW72.00.01 – Health and Safety Checklist and NW72.11.02 – Working near the Orion network –
	b) service measures	9.6.5	
	c) target service levels	9.6.5	
	d) description of target service levels	9.6.5 – 9.6.6	
	e) comparison and evaluation of actual and target service levels for current period	9.6.7	
	f) proposed changes to target service levels	9.6.4	

			competency)) • Connection management policies (refer NW70.50.03 – 9.6.1) • Underground conversion policy (NW70.00.10) • Environmental Management Manual (NW70.00.08) • Environment procedures (refer NW70.10.02 – oil and fuel, and NW70.10.06 – SF6 gas) • Environmental risk register (NW70.10.06) • Contract works environmental audit policy (NW73.10.18)
D5 Network asset information	(1) Description of		11kV network architecture review NW70.53.01 Substation design Asset management reports
	a) distribution area	9.7.2	
	b) existing network configuration	9.7.3	
	c) distribution substation arrangements	9.7.4	
	d) low voltage network	9.7.5	
	e) secondary assets	9.7.6	
	f) existing network assets by asset category	9.7.3	
	g) regulatory asset values by asset category	9.7.8	
	h) regulatory asset values by asset sub category	Appendix 26	
D6 Demand, consumer numbers and generation forecasts	(1) For each key assumption		
	a) how relied upon	9.8.6	
	b) forecast methodology for demand forecasts	9.8.2, 9.8.3, 9.8.4, 9.8.5	NW70.60.12
	c) explanations regarding:		
	i. large loads		NW70.60.12
	ii. consumer numbers	9.8.6	
	iii. energy volumes	9.8.2 and 9.8.3	
	iv. energy usage	9.8.6	
	v. embedded generation	9.8.6	
	vi. distributed generation	9.8.6	
	vii. demand management	9.8.6	
	(2) Explanation as to:	9.8.2	
	a) consistency with historical observations	9.8.6	
	b) internal consistency of forecast data	9.8.6	NW70.60.12

	c) consistency of method with forecast quantities as per clause 5.4.3(7)	9.8.6 and 7.2.3	
D7 Capital expenditure	(1) For each capex category:		
	a) overall description	9.13 - 9.17	
	b) deliverability	9.13 - 9.17	
	c) documents, policies and consultants reports	9.13 - 9.17	
	(2) For each identified programme: a) overall description b) deliverability c) contingencies d) assumptions, obligations, step changes e) departures from consultants recommendations f) forecast methodology	9.13.1, 9.15.1 and 9.16.1 address a) – f)	CPP1, CPP54, CPP36, CPP50, CPP53 Project Summaries
	(3) For each identified policy: a) how accounted for and complied with b) how planning standards incorporated	9.13.1, 9.15.1, 9.16.1 and Appendix 21 addresses a) and b)	CPP1, CPP54, CPP36, CPP50, CPP53 Project Summaries
	(4) For each key forecast assumption: a) method and information used b) how applied and affect on capex forecast	9.13.1, 9.15.1, 9.16.1	CPP1, CPP54, CPP36, CPP50, CPP53 Project Summaries
	(5) For each identified programme, relevant information beyond end of forecast	9.13.1, 9.15.1, 9.16.1	CPP1, CPP54, CPP36, CPP50, CPP53 Project Summaries
	(6) For non identified programmes explain: a) how policies and planning standards incorporated b) contingencies	9.13.12, 9.14.1, 9.15.2, 9.17 and Appendix 21 addresses a) and b)	CPP2 - CPP65 Project Summaries (excluding CPP1, CPP54, CPP36, CPP50 and CPP53)
D8 System growth capital expenditure	a) planning standards and assumptions	9.13.6	
	b) prioritisation methodology	9.13.4	
	c) network constraints due to load increases	9.13.7	

	d) land and easement purchase policies	9.13.15	
	e) embedded and distributed generation policies	9.13.9	
	f) non-network solutions policies	9.13.9	
	g) additional rationale for policies	n/a	
	h) analysis of network and non-network development options	9.13.9	CPP1 – CPP20, CPP54 Project Summaries
	i) planning decisions in respect of each target service level	9.13.16	
	j) description of system growth programme including:	9.13	
	i. embedded and distributed generation and non network solutions	9.13.9	
	ii. actions to be undertaken and linkages to forecast expenditure	9.13.11, 9.13.12	CPP1 – CPP20, CPP54 Project Summaries
	iii. detailed description of projects/programmes commenced or committed		
	iv. description of planned projects/programmes	9.13.11, 9.13.12	CPP1 – CPP20, CPP 54 Project Summaries
D9 Asset replacement and renewal capital expenditure	(1) Provide:		
	a) policies and assumptions based on: i. age or reliability ii. replacement versus renewal	9.15	Asset Lifecycle Management Reports (NW70.00.22 – NW70.00.44)
	b) rationale for policies and assumptions	Appendix 21	
	c) asset replacement models used	9.15	CBRM Models and EAT CBRM Report (March 2012)
	d) description of replacement and renewal programmes for each asset category	9.15.1, 9.15.2	CPP30 - CPP43 Project Summaries
	(2) Extent to which information consistent with (1) above: a) taken into account in the forecast b) affected forecast versus actual	9.15	CPP30 - CPP43 Project Summaries

	(3) Explain how associated system growth capex has been taken into account	9.15	
D10 Reliability, safety and environment capital expenditure	a) Implications of: i. new obligations ii. substantive amendment to current obligation b) how taken into consideration in CPP proposal	9.14	CPP51 and CPP52 Project Summaries
	c) relevant- i. risk management policies ii. risk assessments and risk mitigation in current period iii. risk mitigation in next period	9.14 and 9.9	CPP51 and CPP52 Project Summaries
	d) rationale for policies	Appendix 21	CPP51 and CPP52 Project Summaries
D11 Non-system fixed assets capital expenditure	Rationale for expenditure in largest two expenditure categories	9.16, 9.16.1	CPP50 and CPP53 Project Summaries
D12 Operating and maintenance expenditure	(1) for each opex category: a) overall description b) deliverability c) documents, policies and consultants reports	9.19, 9.20, 9.21, 9.22, 9.23, Appendix 21	
	(2) for each identified programme a) provide i. overall description ii. deliverability iii. contingencies b) identify: i. key assumptions ii. obligations iii. step changes c) explain: i. base year forecasting ii. departures from consultants recommendations iii. forecasting method	9.19.5, 9.20.7, 9.21.6, 9.22.1, 9.23.5 for a) to c)	CPP118, CPP101, CPP109, CPP167, CPP160 Project Summaries
	(3) details of forecasting methods	9.19.5, 9.20.7, 9.21.6, 9.22.1, 9.23.5	CPP118, CPP101, CPP109, CPP167, CPP160 Project Summaries
	(4) how policies:	9.19, 9.20, 9.21,	

	a) taken into account and complied with b) relevant planning standards	9.22, 9.23 Appendix 21 for a) and b)	
	(5) key assumptions a) method and information b) how applied and affect on forecast	9.19.5, 9.20.7, 9.21.6, 9.22.1, 9.23.5 for a) and b)	CPP118, CPP101, CPP109, CPP167, CPP160 Project Summaries
D13 General management, administration and overheads operating expenditure	(1) For overheads opex: a) identify: i. key assumptions ii. relevant obligations iii. step changes b) explain: i. base year forecasting	9.23	CPP160, CPP161, CPP164, CPP165, CPP166, CPP168, CPP169, CPP170, CPP171 Project Summaries
	(2) forecasting methodology a) benchmarking b) historical trends c) contingencies d) step changes	9.23	CPP160, CPP161, CPP164, CPP165, CPP166, CPP168, CPP169, CPP170, CPP171 Project Summaries
	(3) how policies taken into account and complied with	9.23.4, Appendix 21	CPP160, CPP161, CPP164, CPP165, CPP166, CPP168, CPP169, CPP170, CPP171 Project Summaries
	(4) key assumptions a) method and information b) how applied and affect on forecast	9.23	CPP160, CPP161, CPP164, CPP165, CPP166, CPP168, CPP169, CPP170, CPP171 Project Summaries
D14 Operating expenditure projects and programmes	For each non identified project and programme: a) how policies taken into account and complied with b) relevant planning standards c) contingency factors	9.23, Appendix 21	CPP161, CPP164, CPP165, CPP166, CPP168, CPP169, CPP170, CPP171 Project Summaries
D15 Self-insurance	(1) for proposed self-insurance allowance: a) provide:	9.23.7	CPP60 Project Summary
	i. uncertainties provided for ii. methodology iii. actuarial report on risk premium iv. quotes from external insurers	n/a	
	(2) For each quote: a) state:	n/a	

	i. amount insured ii. premium payable iii. deductibles iv. terms and conditions v. why not suitable		
	(3) Explain whether remediation costs otherwise recoverable	n/a	
D16 Controllable opex	For each year of the next period:		
	a) opex included in forecast controllable opex	n/a	
	b) justification for this inclusion	n/a	
D17 Related parties	• identify related parties	9.25.1	
	• identify relevant projects and programmes for each related party	9.25.2	
	• for each related party: a) nature of services relevant to each project and programme b) date and term of contract	9.25.2, Appendix 31	
	• for each service: a) description of tendering process b) relevant documents c) explain:	9.19.3, 9.25.3, Appendix 32	Supporting contractual and tender documents available to Commission and verifier
	i. why outsourced	9.19.3, 9.25.3	
	ii. discrete or broader contract arrangements	9.11.2, 9.19.3, 9.25.3	
	iii. competitive procurement basis		
	iv. sub-contracts		
	• contract price methodologies, consultants reports or assumptions	9.11.2, 9.19.3, 9.25.1	

D18 Unit costs and expenditure escalators	(1) for unit rate assumptions:	n/a	NW70.60.13 NW70.60.15
	a) identify:		
	i. source material		
	ii. date developed		
	iii. historical unit rates for plant and equipment		
	b) explain:		
	i. how developed		
	ii. whether quantum is reasonable		
	(2) for labour or materials escalators:	9.26	
	a) class of labour or materials	9.26.3	
	b) provide:		
	i. base year and unit rates	n/a	
	ii. escalators	9.26.3 – 9.26.5	
	iii. quantum of labour costs	9.26.6	
	iv. quantum of material costs	9.26.6	
	v. real and nominal escalators	9.26.5	
	c) explain:	9.26.3 – 9.26.5	
	i. methodology		
	ii. weightings		
	iii. consistency between capex and opex forecast		
	iv. explain any inconsistency		
	v. additional contingencies		

9.2.2 Consistency with other information provided under Part 4 obligations

In accordance with Schedule D2(2) we have considered the extent to which the information included in this CPP proposal in response to Schedule D is consistent or otherwise with the most recent information we have previously provided under any obligation under Part 4 of the Commerce Act. We summarise our assessment below

Other information provided under Part 4 of the Commerce Act

Requirement	Last published/provided to the Commission	Explanation
Annual historical disclosures in accordance with 2008 IDRs	August 2010 for FY10	This CPP proposal includes historical information pertaining to capex, opex, demand and associated network statistics. It is consistent with that previously disclosed, except that changes have had to be made to ensure consistency with the IMs and section 53ZD Notices.
AMP in accordance with 2008 IDRs	March 2012	While our underlying asset management planning processes described in our 2012 AMP are consistent with this proposal, our forecasts in this CPP proposal supersede those included in our 2012 AMP due to subsequent planning and analysis. Our AMP to be publicly disclosed in March 2013 will be consistent with the information contained in this CPP proposal, although it will be published in accordance with the October 2012 ID Determination
Section 53ZD Notices	14 November 2012 29 November 2012	Our information in this section of our CPP proposal is consistent with information provided in response to each section 53ZD Notice
2012 DPP Compliance Statement in accordance with 2010 EDB DPP Determination	6 June 2012	Our SAIDI and SAIFI information contained in this proposal is consistent with the information provided in our FY12 DPP Compliance Statement Our FY10 billable quantities, used to forecast weighted average growth in quantities for this proposal, are consistent with the information contained in our FY12 DPP Compliance Statement

9.2.3 Required information omitted from this proposal

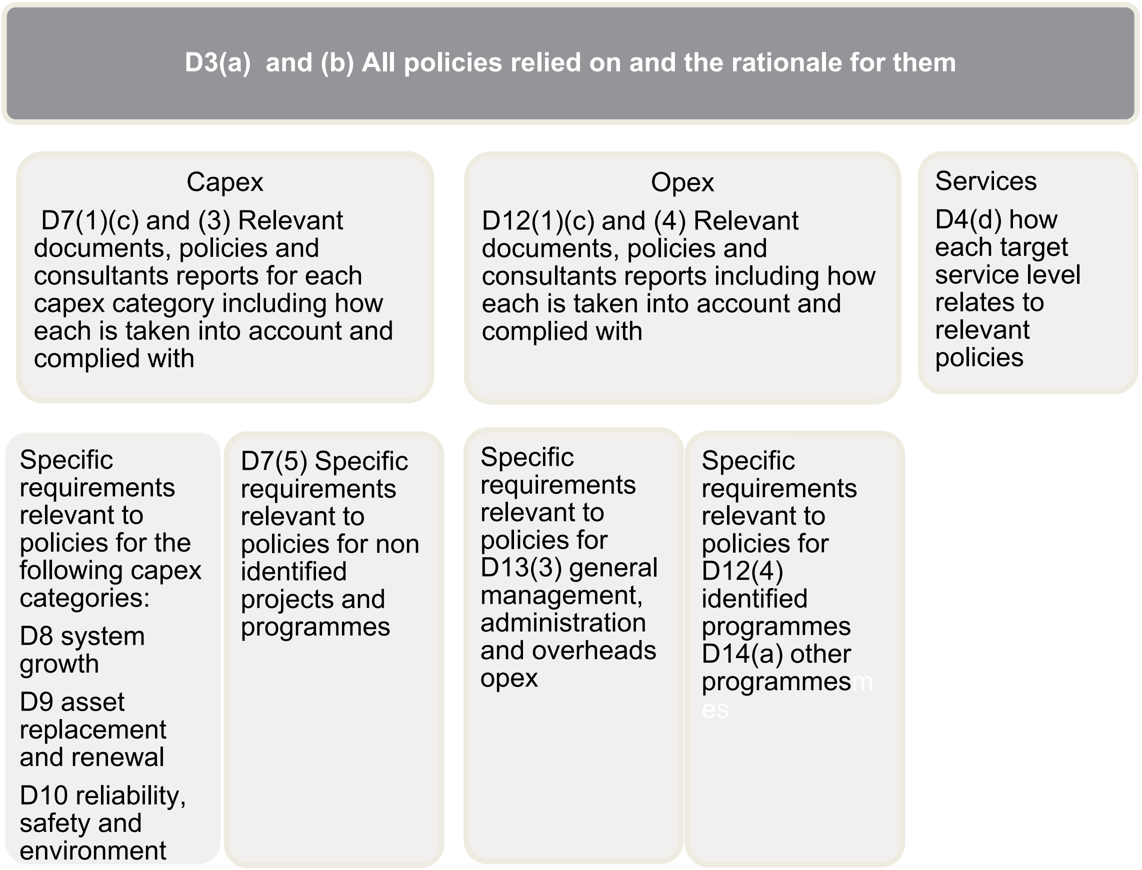
In accordance with Schedule D2(3), no information prescribed in Schedule D has been omitted from this proposal.

9.3 Qualitative information

IM D3

9.3.1 Policies, documents and consultants' reports

Clause D3 requires a list of all policies we have relied on in preparing our expenditure and demand information specified in Subpart 4, Section 8 of Part 5 of and Schedule D of the IMs. Other clauses in Schedule D also set out requirements for information and linkages to policies and documents and consultants' reports. These requirements are summarised in the following diagram.



D3(a) and (b) All policies relied on and the rationale for them

Capex
D7(1)(c) and (3) Relevant documents, policies and consultants reports for each capex category including how each is taken into account and complied with

Opex
D12(1)(c) and (4) Relevant documents, policies and consultants reports including how each is taken into account and complied with

Services
D4(d) how each target service level relates to relevant policies

Specific requirements relevant to policies for the following capex categories:
D8 system growth
D9 asset replacement and renewal
D10 reliability, safety and environment

D7(5) Specific requirements relevant to policies for non identified projects and programmes

Specific requirements relevant to policies for D13(3) general management, administration and overheads opex

Specific requirements relevant to policies for D12(4) identified programmes D14(a) other programmes

As illustrated above there is considerable overlap between the various clauses within Schedule D in this respect. Our approach to meeting these requirements is as follows:

- Appendix 21 includes a full list of policies relevant to the CPP proposal. It also includes an explanation of the rationale for each policy (or group of policies as appropriate)
- Appendix 22 identifies any consultants reports relied upon in the context of each policy, and in preparing the capex and opex forecast
- further information about our policies, standards and specifications is included throughout the remainder of Section 9, where relevant to:
    - target service levels (Section 9.6)
    - capex categories (Sections 9.13 – 9.17)
    - opex categories (Sections 9.19 – 9.23)
    - identified projects and programmes (Sections 9.13 – 9.23 as appropriate)
    - other projects and programmes (within each Project Summary document).

Project summary documents

As explained in Section 8.5.1, we have prepared a Project Summary document for every capex and opex project and programme. These set out:

- a description of the project or programme
- its aims and objectives
- the drivers for the project or programme
- the obligations we are meeting
- relevant policies and consultants' reports
- deliverability and prioritisation
- key assumptions
- the impact of the earthquakes on the project or programme
- the basis for our expenditure forecasts.

Our Project Summary documents for identified projects and programmes are included with this CPP proposal (as appendices 36 and 37). They are more detailed than those for the remaining projects due to the additional IM information requirements for identified projects and programmes. Project Summary documents for other projects and programmes are available as supporting information.

Defining policies

For the purpose of this CPP proposal, we have defined 'policies' to mean all of our controlled documents. These comprise:

- corporate and network management policies, plans and registers
- asset lifecycle management reports
- operating standards, procedures, manuals and instructions
- design standards
- technical specifications and standards
- equipment specifications
- guidelines and information packs.

Our approach to the management of these policies is set out in our document control standard NW70.50.03 (itself a controlled document).

9.3.2 Linkages to AMPs

Schedule D3 requires an index of explicit references to our AMP, where information from the AMP has been included in this Section of our CPP proposal. This is set out in Appendix 23.

9.4 Our asset management planning

Our expenditure plan in this CPP proposal has been prepared consistent with our overarching asset management planning practices, which reflect our lifecycle management strategy for our electricity assets. We aim to manage our assets prudently to provide a resilient, reliable and appropriate quality service. We use innovative asset management practices to ensure that electricity is delivered efficiently for the long term benefit of our consumers.

Our support activities, those not directly related to constructing, maintaining and renewing our electricity distribution system, support our core asset management processes. Our infrastructure team is responsible for developing and implementing our asset management policies and practices. Our corporate teams (corporate, commercial, IT, HR, communications) provide the necessary systems, management support and direction to enable these functions to operate efficiently and effectively.

9.4.1 Our asset management plan

Each year we publish a comprehensive 10 year network AMP, which summarises our plans to develop and maintain our network. The overall objective of our AMP is:

> *To provide, maintain and operate Orion's electricity network while meeting agreed levels of service, quality, safety and profitability.*

Our AMP document has:

- a summary of the plan
- background and objectives
- target service levels
- details of assets covered and lifecycle management plans
- load forecasts, development and maintenance plans
- risk management, including policies, assessment and mitigation
- performance measurement, evaluation and improvement initiatives.

Our AMP assists us to meet our Part 4 regulatory reporting requirements. The extensive detail in our plan is used on a day-to-day basis by our employees and demonstrates responsible stewardship of our network assets on behalf of our shareholders, retailers, government agencies, contractors, electricity end users, financial institutions and the general public.

Our AMP aims to optimise our lifecycle costs for each network asset group (including creation, operation, maintenance, renewal and disposal) to meet agreed service levels and future demand. Each year we aim to improve our AMP to take advantage of new information and changing technology. These innovations help us to maintain our ranking as one of the most resilient, reliable and efficient electricity networks in the country.

Our current AMP

Our current AMP was published in March 2012, and applies to the 10 year planning period commencing on 1 April 2012. A copy of this document can be found at http://www.oriongroup.co.nz/publications-and-discloures/asset-management-plan.

We are currently finalising our next AMP which will apply for the 10 years commencing 1 April 2013.

Updating our AMP annually is part of our normal planning process. It allows us to seek continuous improvement in our asset management planning, and to respond to external events which have occurred in the prior year. This is particularly important for us now as the consequences of the earthquakes are still emerging and the region's recovery phase is just beginning.

Our network recovery will be influenced by the wider Christchurch rebuild and we must retain some flexibility in our plans to accommodate the changing needs of our consumers and city planners, in particular CERA, SCIRT and CCC.

Our 2012 AMP does not include expenditure forecasts for our corporate and infrastructure management opex and non network capex.

2013 AMP

The capex and opex forecasts presented in our draft 2013 AMP, which will be published before the end of March 2013, will be consistent with the information presented in this CPP proposal.

Our underlying asset management planning processes and practices, which are summarised in our current AMP, are consistent with those assumed when preparing this CPP proposal. Those processes and practices will also be reflected in our 2013 AMP.

Our 2013 AMP will be extended to include specific plans and expenditure forecasts for our corporate and infrastructure management opex and non-network capex. This is a new requirement of the October 2012 ID Determination.

Relationship between our AMP and our mission

Our activities are guided by what we call our 'mission', which consists of a purpose statement, a vision statement for the future state of the company and a set of company values as detailed below. Specific capability that we must have to achieve this mission include; asset management, stakeholder communication, risk management and fair network pricing. Our AMPs are consistent with, and are an important part of, our mission.

The three key elements of our mission comprise our purpose, our vision and our values. This mission is consistent with the Commerce Act, Part 4 purpose statement (as set out in section 52A of the Act) which is to promote the long term interests of our consumers.

We aim to meet these objectives by investing wisely and innovatively, while ensuring we invest sufficiently to maintain safe and secure electricity supplies for our current and future consumers.

Our mission is also guided by the requirements of the Energy Companies Act (Section 36), which requires our principal objective to be *'..to operate as a successful business'*.

The consistency between our mission and the Part 4 Purpose Statement is illustrated in the following table.

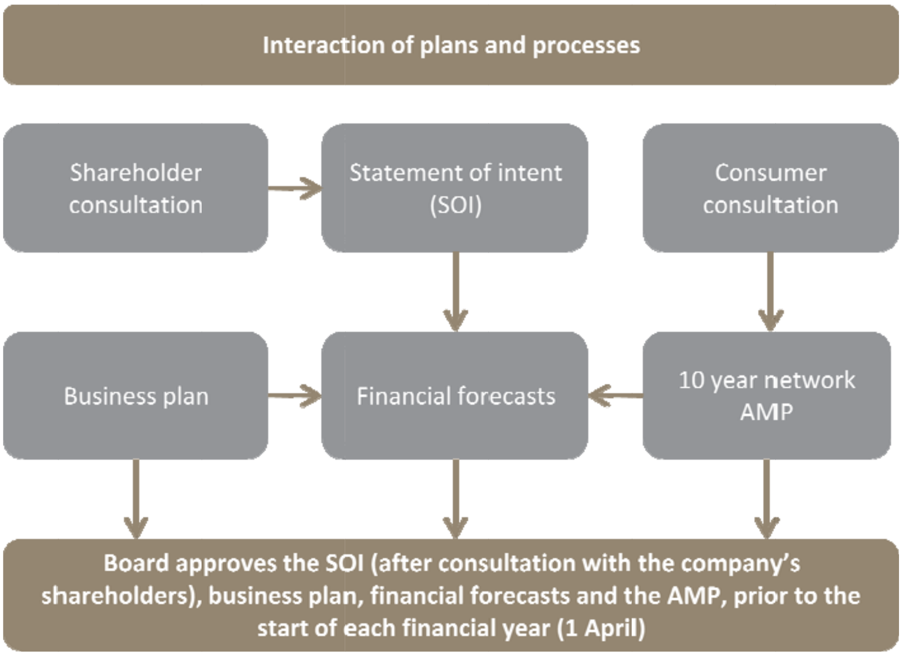
Our Mission		
Key elements		**Relationship with the Part 4 (s52A) Purpose Statement**
Our purpose	We consistently deliver a safe, secure and cost-effective supply of electricity to our customers. We aim to:	Consistent with the overall section 52A purpose of acting in the long term interests of our consumers. Addresses both the quality and cost of our services to consumers.
Our vision	• provide excellent customer service • foster strong stakeholder relationships	• clause (b) – meeting consumer demands
	• lead collaboration across the electricity industry to benefit all New Zealanders	• clauses (a), (b) and (c) – supports innovation and efficiency improvements
	• apply technology and demand side management to benefit our customers.	• clauses (a), (b) and (c) – supports innovation and efficiency and lower prices for our consumers
	• excel in leadership and management • attract, develop and retain the very best people	• clauses (a), (b) and (c) – supports innovation and efficiency and meeting consumer demands for quality of service
	• protect and create value for our shareholders and customers.	• clauses (a), (c) and (d) – supports efficient prices for consumers while ensuring shareholders receive normal/fair returns which are necessary to incentivise investment and innovation.
Our values	We will: • value relationships • be trustworthy • be proactive • maintain a long term focus • be effective and efficient • be innovative • value safety and well being • value our natural environment.	Our values help us to achieve our purpose and vision. Our long term focus is directly relevant to the overall section 52A purpose. Efficiency, effectiveness and innovation are core parts of the purpose statement. Safety of our staff, contractors, our consumers and the public is critical to us, and we must meet our environmental obligations in order to provide the services our consumers demand.

Relationship between our AMP and our corporate plans and objectives

Our AMP is a key part of our business planning process. Our processes combine management, financial and technical practices to ensure that the level of service required by our consumers is provided by us at the lowest long term cost.

The diagram below illustrates how our AMP interacts with our wider corporate planning processes. Consumer consultation is an important component of our planning and helps us to ensure we are providing our services consistent with the long term interests of our consumers. We are planning for urban security of supply standards for, for example, an industrial park development (Izone) located in our rural network (near Rolleston). This is consistent with the reliability expectations of the consumers located within that park. Our AMP consultation processes are described further in Section 9.6.6. In late 2012 we also undertook specific consumer consultation on our draft key CPP proposals, which is described fully in our CPP application.

The following diagram shows the high level interaction between our key governance and planning documents.



Our CPP application process has required us to accommodate an additional step in our 2013 planning process. As the CPP IMs are prescriptive about the information we must provide, we have had to prepare information in a different form to that we normally use.

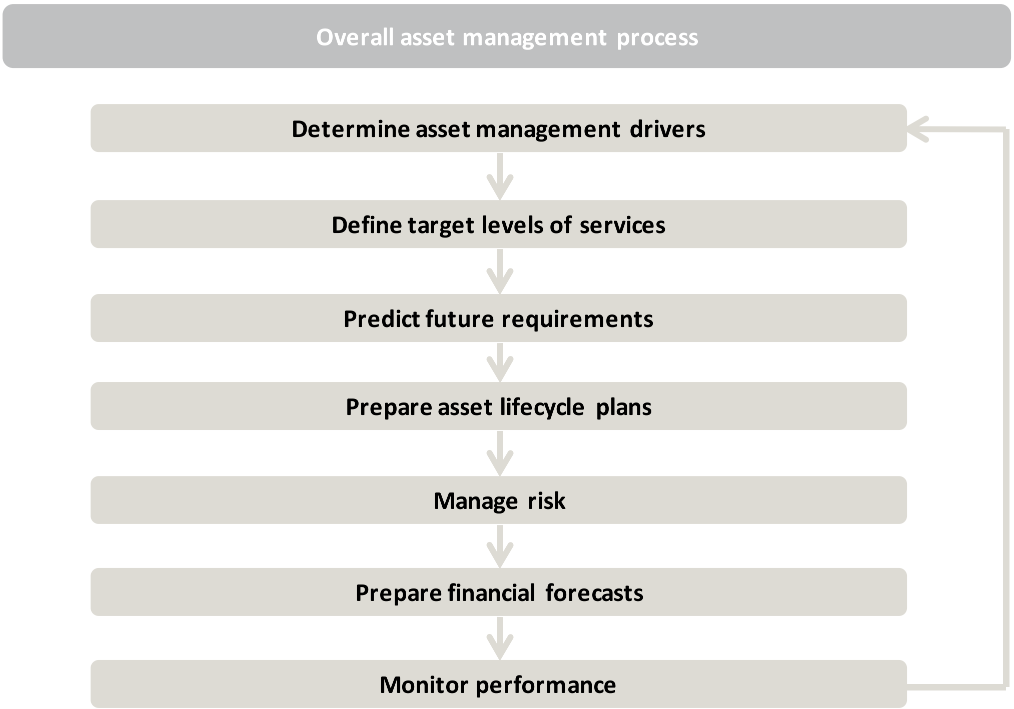
We are also required to provide a higher level of commitment under a CPP than we would through our normal AMPs. This is because, once determined, the CPP will apply until FY19, and it will not be possible to accommodate unforeseen circumstances in the CPP price path or quality standards. This has been a particular challenge for us given that Christchurch is only just at the start of the recovery and rebuild phase, and there is considerable uncertainty regarding the nature and pace of the city rebuild and relocation. In other words, the prescriptive nature of our CPP forecasts 'assumes away' the medium to long term uncertainty and flexibility inherent in our historical AMP planning.

9.4.2 Asset management policy

Our AMPs are supported by an overarching asset management policy. A copy is attached as Appendix 24. This policy outlines the asset management practices we use on our network assets. Our CPP proposal has been prepared consistent with this policy. Key elements of this policy are presented throughout the remainder of this section of our CPP proposal.

9.4.3 Asset management process

Our approach to our asset management process can be summarised in the diagram below. In the following sections we outline our key asset management drivers and the systems and information we use to assist us. In subsequent sections we cover the remainder of our asset management processes: service levels, future needs, asset lifecycle plans, risk management, expenditure plans and asset performance.

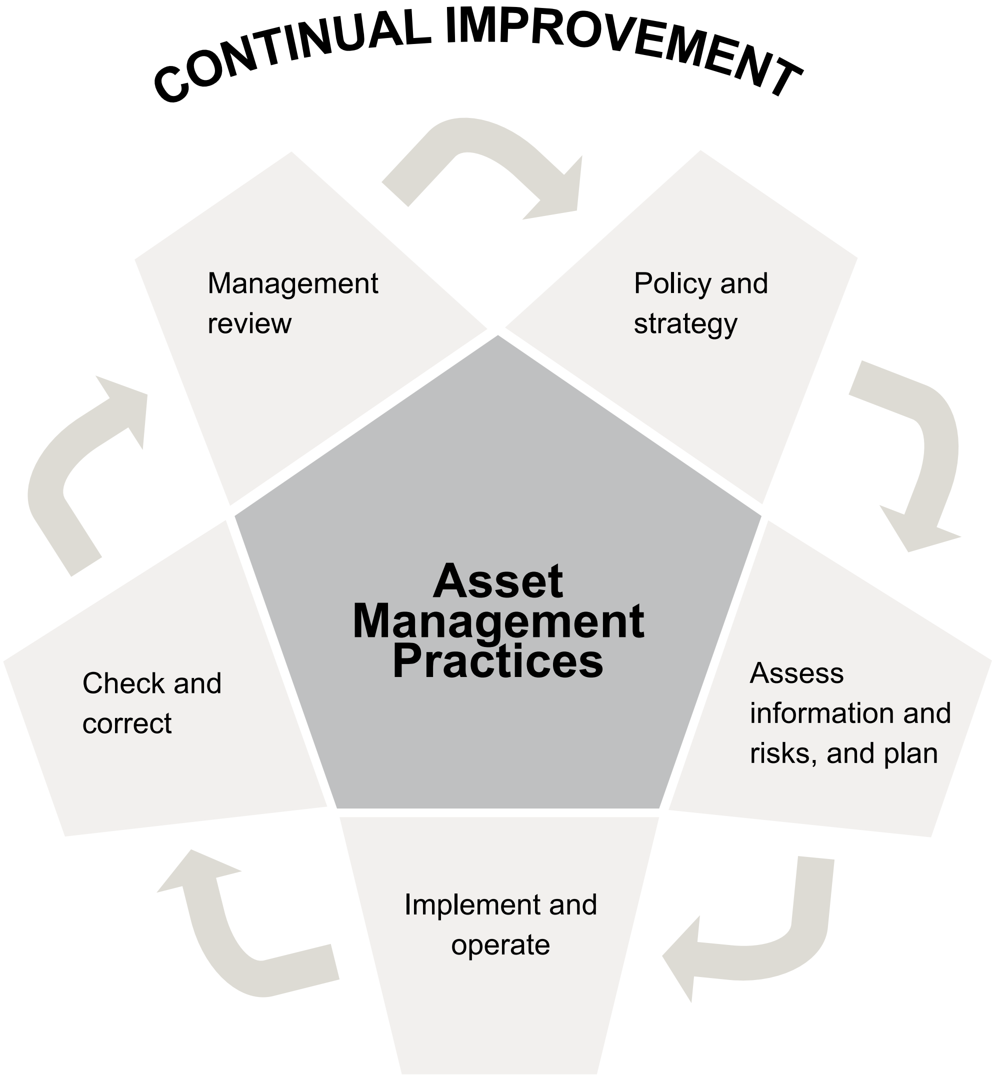


In the remainder of this section of our CPP proposal we address each one of these steps in our overall asset management process.

9.5 Asset management drivers

9.5.1 Continual improvement

Our asset management practices seek to achieve economic efficiency by adopting a philosophy of continual improvement as illustrated below:



We aim to achieve a fair return to our shareholders while delivering electricity to consumers commensurate with the quality of supply they need. These objectives are maintained over time by our asset management practices which seek economic efficiencies by:

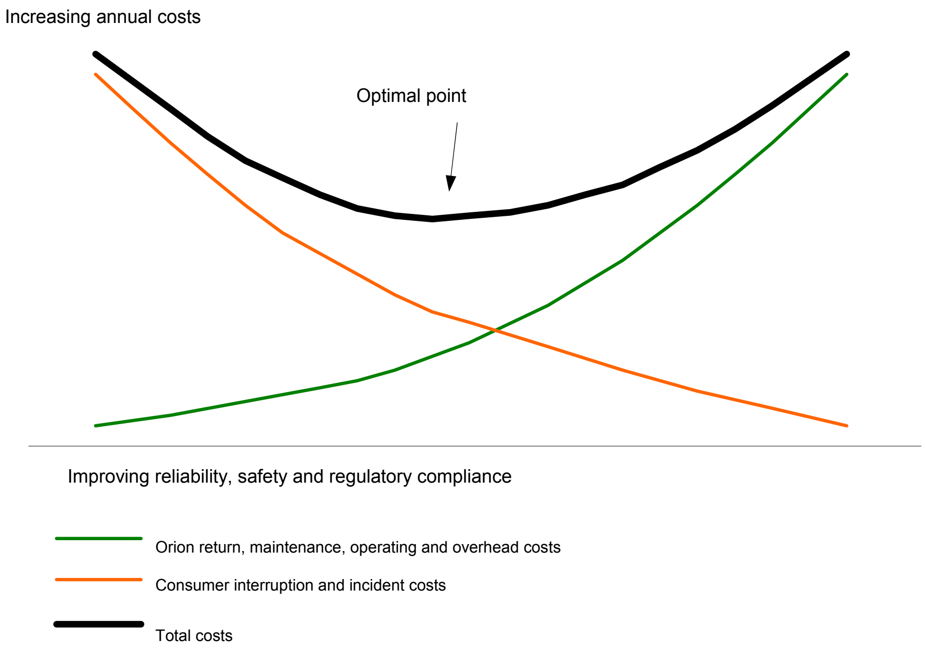
- providing a basis for monitoring asset performance and utilisation
- enabling asset managers to plan and prioritise maintenance, renewal and growth expenditure
- quantifying risk, and mitigating the impact of failures
- extending the life of assets and optimising the trade-offs between maintenance and replacement to ensure lowest lifetime costs
- tendering all possible work to competent contractors, thus ensuring the best prices are achieved in our development projects and maintenance programmes
- assessing alternative options for all major projects
- optimising distribution losses and network utilisation.

9.5.2 Investment in innovation

Our network delivery service has a cost. On the other hand non-supply (or network outages) also has a cost, which is borne by consumers.

When we extend, replace, maintain and operate our network we consider the balance between cost and the quality of supply provided. This is consistent with the long term interests of our consumers. These trade-offs are reflected in the four strands in the section 52A purpose statement which require efficient investment, efficient prices and appropriate quality of service for consumers while ensuring fair returns on our investments.

Optimal cost versus quality principle



The optimum point of investment in our network is achieved when the marginal cost of further expenditure by us just exceeds the marginal value of benefits (better network reliability) to our consumers. We seek to achieve this optimal point by economic analysis when we develop and review our asset management practices.

To achieve optimal outcomes, we commit significant resources to participate actively in the consultation phases when national rules and regulations are developed. We believe it is important that the rules and regulations that affect our industry are well-informed, principled and practical. We commit resources to Electricity Networks Association (ENA), Electricity Engineers Association (EEA) and Electricity Authority (EA) industry working parties. We have also assisted with working groups for developments to industry regulations, for example the Electricity (Hazards from Trees) Regulations, the Distributed Generation Regulations and electricity industry standards groups.

The speed at which new asset and systems technologies has become available has increased in the last decade. We welcome new technologies and are committed to keeping up-to-date with technological advancements. In line with our 'optimal investment point' approach, we introduce new technologies only when they result in an appropriate economic balance between cost and network performance. At that time, we modify our standards and specifications to include the initiative.

Our recent introduction of Ground Fault Neutralisers (GFNs) is an example of a new technology introduced to assist with rural reliability performance.

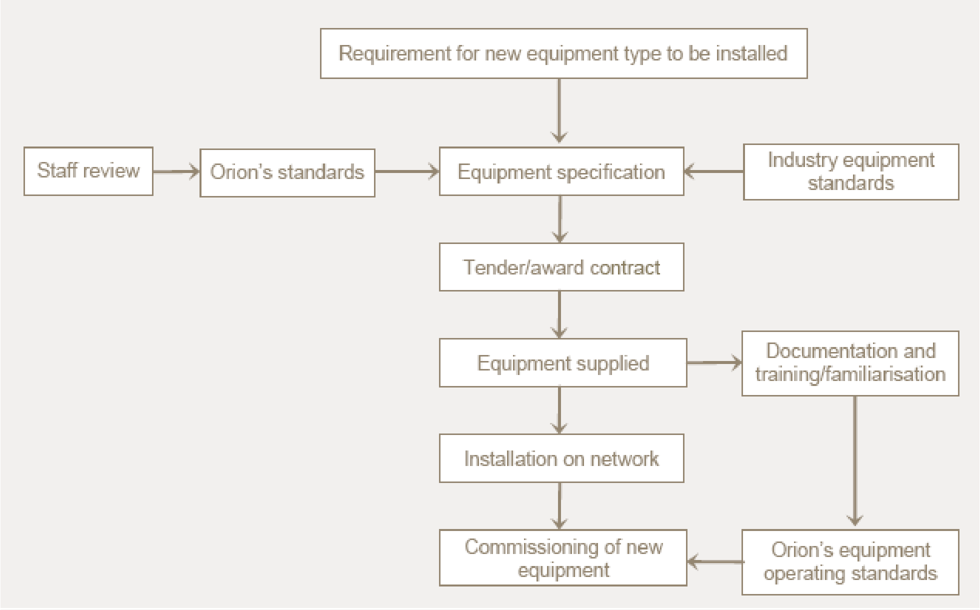
In addition we are currently moving to fully enclosed Ring Main Units (RMUs) to replace the Magnefix substation switching units we have traditionally installed on the network. The RMUs improve our ability to comply with arc flash containment and safe working clearances on our 11kV network.

More information is provided in our 11kV architecture review, included as Appendix 7.

Introduction of new equipment types

New equipment types are reviewed to carefully establish any benefits that they may provide. Introduction is carried out to a plan to ensure that the equipment meets our technical requirements and provides cost effective benefits. All equipment must be able to be cost effectively maintained and operated to provide safe and effective service to support our security of supply standards.

Process to introduce new equipment



9.5.3 Environmental, safety and legislative requirements

We are committed to being environmentally responsible. Legislation such as the Resource Management Act and our environmental sustainability policy affect our activities. We aim to minimise our environmental impact by incorporating the cost of carbon into our network purchasing decisions. Approximately 77% of our carbon footprint is due to electrical losses in our network[31]. We have now included specific carbon costs to the cost of electrical losses when undertaking our investment analysis.

We aim to meet our health and safety obligations. Like all companies we are subject to the general provisions of the Health and Safety in Employment Act 1992, which has far-reaching impacts. Other specific safety requirements are found in the Electricity Act, the Electricity Regulations and the Building Act. In particular, in respect of asset management we:

- adopt appropriate safety standards for the creation of new assets
- specify works to maintain assets in a safe condition
- operate and work safely with documented procedures
- develop appropriate risk management practices.

As a general principle, significant electrical hazards within the public arena are controlled using two barriers of protection. Signage on the initial locked barrier alerts visitors to the general hazard and that access is restricted to authorised personnel only. The second barrier has further warning signage and a barrier preventing inadvertent contact with the hazard. The form of the barriers may differ depending on the level of risk and the practicality of implementation.

We aim to achieve material compliance with all relevant legislation, regulations and codes of practice that relate to how we manage our electricity distribution network.

These include:

- Electricity Act
- Energy Companies Act
- Commerce Act
- Local Government Act
- Electricity Amendment Act
- Resource Management Act
- Electricity Reform Act
- Building Act
- Electricity Regulations
- Health and Safety in Employment Act
- Electricity (Hazards from Trees) Regulations
- Health and Safety in Employment Regulations
- Public Bodies Contract Act
- NZ Electrical Codes of Practice
- Public Works Act
- Civil Defence Emergency Management Act.

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[31] Refer 2009 MWh report exploring Orion's carbon footprint. Calculation based on 2007 losses and a New Zealand average of 0.209 tCO_2e per MWh.

9.5.4 Information and systems

Good information and systems are critical to effective asset management. Our information management systems are used to document the existing asset components of our network and provide access to data to develop, maintain and operate our business. The various systems and information flows between them are shown in the diagram included in section 2.7 of our AMP.

A description of the functionality of our main systems is included in section 2.7 of our AMP.

Planned improvements

A new outage management system is in the final stages of implementation. It is built on the PowerOn network management system foundation that we implemented in 2009. It significantly improves our ability to respond to network outages for maintenance and especially during major events. Further developments including real-time distribution power flow analysis are in the planning stages.

A pilot document management system implementation is also in progress, built around the Microsoft Sharepoint toolkit. The benefits will be significantly improved management of corporate documents, including scanned images.

9.5.5 Asset data

The majority of our primary asset information is held in our network asset register, GIS system and cable databases. We hold information about our network equipment from GXP connections down to individual LV pole level with a high level of accuracy. The data has improved over time due to various inspections and projects since we introduced our GIS system and asset register.

Requirements to improve information have been driven by improved asset management plans, regulatory compliance and better risk identification and management. This has ensured that we have the ability to locate, identify and confirm ownership of assets through our records.

Although minor data errors will occur and improved information will always be required, we believe that our information for the majority of our network data is up to date and accurate. Some information for older assets installed more than 15 to 20 years ago has been estimated based on best available data. Examples of this include:

- the conductor age for some lines older than circa 1990
- timber poles that went into service prior to our use of identification discs
- older air break switches and section fuses.

We have commissioned EA Technology (EAT) to help us implement Condition Based Risk Management (CBRM) models for our network assets. In doing this EAT required access to considerable data about our assets.

In its March 2012 report on the application of CBRM to our network assets, EAT noted that our base asset data was some of the best available for CBRM modelling from any utility worldwide. In particular, EAT noted that our high quality data, coupled with the relatively small size of our network, enabled EAT to produce relatively detailed and sophisticated CBRM models for most asset types on our network. More information concerning our CBRM project is included in Section 9.15. EAT's report is available as supporting information to this proposal.

Refinement of our data is an ongoing process. Compliance inspections and maintenance regimes are the main source from which to confirm or update data. As we replace aging assets over time, estimated data will be superseded.

The only data we believe needs to be materially improved is determining accurate connection assets for individual LV consumers. This information is not easily accessible as it requires manual searches through archived information. The requirement for this information is not deemed to be a high priority and this data will be sourced through our ongoing inspection programmes over the next five years.

9.5.6 Documented policies and procedures

We standardise our construction and work practices where practicable. Written standards, procedures and specifications are critical to our outsource model because we have a number of different parties working on our network at any one time. Documented policies and procedures help us to implement our work programmes.

Controlled documents

Our document control policy (NW70.50.03) contains a full controlled document list, and our processes for their control, distribution, format and approval. Our Data Manager is responsible for the controlled documents. One planned improvement is the introduction of a company-wide document management system. This will assist us to manage and track our controlled and non-controlled documents. This is expected to be implemented by FY15.

The following table describes the types of controlled documents we have. These support our expenditure plan and references to relevant policies and procedures are included throughout this CPP proposal.

Policies and procedures

Category	Sub category	Explanation
Corporate		We have a range of policies, plans and registers that underpin our SOI, business plan and AMP to enable the efficient and effective management of our business
Infrastructure	Management	We have a range of policies, plans and registers that enable the efficient and effective that support our network management and operational responsibilities
	Asset lifecycle management reports	Our asset lifecycle reports set out the criteria and asset management practices used to ensure Orion obtains

	Design standards	effective performance and acceptable service life from each category of assets
	Technical specifications	In order to manage the safety, cost, efficiency and quality aspects of our network we seek to standardise network design and work practices. To achieve this consistency we have developed design standards and drawings that are available to approved designers/contractors. Normally we only accept designs that conform to these standards. However, this should not be construed as a desire on our part to limit innovation. Design proposals that differ from normal are considered if they offer significant economic, environmental and operational advantages We also have a comprehensive set of specifications/work instructions for different activities on our network. These specifications are intended for authorised contractors working on the construction and maintenance of our network. They refer to relevant codes of practice and industry standards as appropriate Our equipment specifications detail accepted performance criteria for significant equipment operating within our network. Usually new equipment must conform to these specifications. However, we are interested in innovation and equipment that differs from normal is considered if it offers significant advantages. Our process for introducing new equipment is described above
Network operation	Management	To ensure our network is operated safely we have standards, procedures, manuals and instructions that cover such topics as the release of network equipment, commissioning procedures, system restoration, worker training and access control. To ensure the wide variety of equipment on our network is operated safely with minimum impact on our consumers, we also have operating instructions that cover each different type of equipment in service on our network. We create a new operating instruction at the time new equipment is introduced
	Operating procedures	
	Operator instructions	
Risk		We have a range of plans and manuals to understand and document risk as it applies to our business and to enable its control and mitigation. Some are required to comply with the Civil Defence Emergency Management Act
Contract management		To enable the efficient and effective management of our contracting model we have a range of policies and process documents to manage the tendering, control and auditing of our contracts and contractors

Connections and embedded generation		These documents cover the management of new connections, including embedded generators, from livening through to disconnection
Procurement and stock management	Management	In order to manage the cost, efficiency and quality aspects of network performance there is a strong desire to standardise on equipment used to construct components of our network. A set of specifications detailing accepted performance criteria for equipment to be installed into our network is available
	Equipment specifications	

9.6 Target levels of service

IM Schedule D4

9.6.1 Introduction

Our principal services are our electricity distribution network delivery service, associated services and discretionary services, which are outlined in our 'Delivery Services Agreement' (DSA)[32].

Some service levels and service measures are set out in our DSA. Some are updated via our SOI. Our AMP sets out our service levels and measures in a comprehensive, consistent and regularly updated format. The relevant sections of our DSA are referred to below and the fuller DSA text is included as Appendix 25.

Extracts from relevant sections of our latest AMP are included below where appropriate to meeting the information requirements of Schedule D4.

9.6.2 Service categories

Schedule D1 requires our services to be categorised as follows:

a) provide and operate network infrastructure between input and offtake connection points and deliver electricity through the network
b) provide load management services

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[32] The references to and extracts from the DSA in this document are to the version published on Orion's website as at 1 October 2012. It is acknowledged that this version contains acronyms (for example references to "MARIA") and is otherwise not entirely up to date (for example certain terms are at odds with recent changes in the Electricity Industry Participation Code). Also, not all of our agreements with retailers are exactly the same as our published version, nor with each other. Orion, like many industry participants, has been waiting for finalisation of the model use of system agreement (MUoSA) by the EA before publishing a new DSA. The EA finalised its MUoSA in September 2012 and we are working through the implications for Orion. Nevertheless, we believe that our published DSA sets out our service obligations in a materially accurate way.

Our DSA is a fairly static document, which is why a regularly updated AMP is crucial to establish and monitor ongoing service levels.

c) provide connection services, including changes of connection point capacity and/or reliability
d) provide for rearrangement of network assets at third party request (includes undergrounding)
e) provide an additional service (or services if necessary) to those listed in paragraphs (a) to (d), specified by the CPP applicant.

We have not included any additional services in respect of e) above.

In the following sections we set out a description of the services provided using the IM service categories, the intended consumers of the service, the processes used to determine the services and any material changes to the services proposed over the next period.

9.6.3 Provide and operate network infrastructure services

These are set out in the DSA and can be summarised as follows:

Key service features and specifications

- delivery services:
  - the provision and maintenance of works for the conveyance of electricity
  - the operation of such works, including the control of voltage and assumption of responsibility for losses of electricity

  Our delivery service includes the responsibility for procuring contracts with Transpower for the connection of our network to Transpower's grid, the allocation of the transmission charges and the calculation and publication of loss factors

- associated services relevant to this service category are:
  - C1 Fault Call Receipt and Field Service Dispatch
  - C6 Power Quality Complaints and Issues
  - C8 Emergency Calls
  - C9 Advance Notice of Planned Interruptions
  - C10 Use of Standby Generation for Load or Capacity Management
  - C12 Complaints Handling Service
- discretionary services relevant to these service categories are:
  - D2 Use of Standby Generator for Energy Shortage
  - D3 Temporary Connections

Identity of the intended consumers of the services

Our services apply to all of our consumers, although we do develop and negotiate individual DSAs for some larger connections with unique service requirements.

Process for determining the features and specifications of each service

As stated above our services are specified in our DSA. These are negotiated contracts with retailers, who on behalf of consumers, contract with us for the provision of electricity distribution services (provide and operate network infrastructure). Our DSA includes a description of the services to be provided, our obligations in providing those services, the retailer obligations to us and agreed performance standards.

As mentioned above, for larger connections with unique service requirements, we develop and negotiate an individual DSA to better capture the services required and the specific charges applicable to their connection and service arrangements.

Any material change to the services in the next period

We are not planning any material changes to these services within the next period. However, the Canterbury earthquakes and aftershocks have had a significantly adverse impact on the company's electricity distribution network reliability, a key service measure. This will have an ongoing material impact on the achievable quality of our delivery services for a number of years. As a result we are seeking to establish new reliability measures as set out in Section 6.

9.6.4 Service measures and targets for provide and operate network infrastructure

Some specific service measures are set out in Schedule B of the DSA. Many of Orion's service obligations are set in accordance with good industry practice. As noted above, while the DSA sets out our services, it is a rather static document not designed for ongoing monitoring. However, the AMP is regularly updated to reflect actual business practice and recent and projected performance.

Our AMP outlines the performance levels required from our electricity network and management team. These predominantly relate to our key service category; provide and operate network infrastructure. The AMP deals with the following network management drivers:

- network performance
- safety
- environmental responsibility
- investment principles
- economic efficiency.

The key to successful management of our network is to meet the expectations of our consumers and other stakeholders. This is consistent with our 'mission' and SOI as described in Section 9.4.1 above.

All of our consultation methods (refer Section 9.6.11 below for a description of how we determined our target service levels) show that, almost without exception, a reliable supply of power at a reasonable price is our consumers' greatest requirement of us. We measure our performance against this primary consumer requirement in a number of ways.

Other service measures such as efficiency, safety, environmental and legislative compliance reflect a range of performance measures (that we monitor) and the external obligations on us. Our performance in these areas often provides advance notice to management about where Orion's performance is heading prior to any change being noticed in our primary reliability targets. With the exception of our system security standards (set out in Section 6.2.7) we do not distinguish between consumer categories in our service level measures or targets.

For some of these other service measures we have not set a specific target value. We explain our rationale for this below.

Provide and operate network infrastructure services

Service description	Service measure	Next period targets	Long term targets	Description of measure	Measurement procedure
Network performance - reliability	SAIDI	FY14 - <105.1 FY15 - <102.5 FY16 - <93.4 FY17 - <89.6 FY18 - <81.0 FY19 - <72.0	< 59.7	Total network – average minutes lost per consumer per annum for all interruptions	Tracking of all planned and unplanned interruptions to our network Extreme event days are capped using the Commission's 2.5 beta MED method (refer Section 6.3.1) All low voltage (400V) faults are excluded All high voltage faults <1 minute duration are excluded Includes Orion interruptions only - Transpower outages are not included.
	SAIFI	FY14 - <1.40 FY15 - <1.35 FY16 - <1.20 FY17 - <1.15 FY18 - <1.01 FY19 - <0.86	< 0.78	Total network - average number of times a consumer is interrupted per annum for all interruptions	
	Faults per 100km of HV circuit	n/a	<11	Faults on HV network	
	Faults per 100km of 66kV circuit	n/a	< 2	Faults on 66kV network	
	Faults per 100km of 33kV circuit	n/a	< 4	Faults on 33kV network	
	Faults per 100km of 11kV circuit	n/a	<12	Faults on 11kV network	
Network performance - restoration	CAIDI	n/a	< 90	The average duration of an interruption to supply for consumers that have experienced an interruption	

	Faults restored within 3 hours	> 60%	> 60%	% of total number of faults where the last consumer is restored in three hours or less	
Network capacity	Delivering reasonable levels of network security	To meet our security standard	To meet our security standard	Any gaps identified against our security standard	Refer Section 6.2.7
Power quality	Steady state level of voltage	< 70	< 70	Voltage complaints (proven)	Tracking of all enquiries
	Level of harmonics or distortion	< 4	< 4	Harmonics (wave form) complaints (proven)	Checks performed using a harmonic analyser
Safety	Safety of employees and contractors	Zero	Zero	Number of lost time accidents	Accident/incident reports
	Safety of public	Zero	Zero	Number of accidents involving members of the public (excluding car v pole accidents)	Accident/incident reports
Environment	SF_6 gas lost	< 1% loss	< 1% loss	Gas lost expressed as a % of the total contained in our network equipment	Set out in Procedure NW70.10.01
	Oil spilt	Zero spills	Zero spills	Oil spills not contained	Set out in Procedure NW70.10.02
Economic efficiency	Capex per annum per MWh of electricity supplied	Perform better than NZ average	Perform better than NZ average	Capital expenditure on Orion's network per MWh of electricity delivered over our network from Transpower GXPs to consumers	Derived from disclosed statistical data
	Opex per annum per MWh of electricity supplied	Perform better than NZ average	Perform better than NZ average	Operating expenditure on Orion's network per MWh of electricity delivered over our network from	

			Transpower GXPs to consumers
Opex per annum per year-end number of ICPs	Perform better than NZ average	Perform better than NZ average	Operating expenditure per annum on Orion's network per year-end ICPs
Capacity utilisation ratio	No target set	No target set	Maximum demand on network divided by distribution transformer capacity
Load factor	No target set	No target set	Average load on the network divided by the maximum load experienced in a given year
Losses	No target set	No target set	The percentage of energy lost between purchase at the GXP and delivery to consumers

We describe the derivation of the measures and targets in the following paragraphs.

Network performance

Reliability

All of our consultations have shown that a resilient and reliable supply of power at a reasonable price is our consumers' key requirement of us. Indeed, this was also a clear message from our consumers (especially in the eastern suburbs) in the days and weeks following the 22 February 2012 earthquake.

Network reliability is measured by the quantity and duration of interruptions to the supply of electricity to our consumers. Our goal is to ensure that our reliability performance meets our regulatory requirements and our consumers' expectations as ascertained by the means discussed in the previous section. Both the primary measures (SAIDI and SAIFI) are explicitly addressed in this CPP proposal and form part of the Commerce Act's Part 4 regulatory requirements of us.

We have set out our proposed SAIDI and SAIFI limits in Section 6 of this proposal. These measures include daily limits to cap the impact of extreme events, such as major weather events. Both of these measures consider both planned and unplanned interruptions of durations longer than one minute on our subtransmission and high voltage distribution system. Low voltage interruptions and those that originate in Transpower's transmission system are not included.

Our primary network reliability measures can be explained as follows:

- SAIDI, or system average interruption duration index, measures the average number of minutes per annum that a consumer is without electricity
- SAIFI, or system average interruption frequency index, measures the average number of times per annum that a consumer is without electricity.

Another network reliability target we use is faults per 100km of network. This is a measure of how each asset class has performed rather than the impact on our consumers. We have set this target after reviewing international reliability data.

Extreme events can have a major impact on an electricity network's reliability. When considering reliability it is more meaningful to look at long term trends in an electricity network's reliability, rather than figures for any one year. The trend of our network reliability measures (SAIDI, SAIFI and faults per 100km of circuit) since the early 1990s shows that our network reliability has improved. This is illustrated in Section 6.2.1.

However, it is not realistic to expect that we can continue to improve our network reliability every year as there comes a point where the added costs outweigh the added benefits, particularly in a predominately overhead rural network. For example, a major improvement in rural reliability would require a large capital investment and a correspondingly large increase in line charges.

Consumers have consistently indicated across our various consultation methods that they were generally satisfied with our pre-earthquake levels of network reliability and that they have concerns regarding prices increasing. In practical terms this means that we do not believe our consumers wish to see increasing levels of reliability beyond pre-earthquake levels if it means higher prices, and we believe that pre-earthquake levels of reliability are a reasonable long term target.

The policies of most relevance to our reliability service targets are our:

- asset management policy (NW70.00.46)
- health and safety policies (OR00.00.01 and 02)
- infrastructure management policies (refer NW70.50.03 – 9.21)
- network operation policies, refer NW70.50.03 – 9.3.1 (management), 9.3.2 (operating standards), 9.3.3 (operating procedures) and 9.3.4 (operator instructions).

Earthquake impacts

As described in detail in Section 6, we are currently unable to provide a level of resilience and reliability consistent with historical pre-earthquake levels. We are working hard to restore our network resilience and reliability, which will ultimately allow us to return our network back to the levels which our consumers enjoyed before the earthquakes.

We have determined SAIDI and SAIFI targets for each year until the end of the CPP regulatory period. The method and rationale for theses target is described in detail in Section 6.

We have not set targets for the remainder of our reliability measures for the CPP regulatory period. We do not yet have enough information about the likely performance of the different classes of assets on our network to be able to set robust and specific targets for all of our normal service measures.

We have included longer term targets for all service measures which we expect will be achieved beyond the CPP regulatory period.

For the purpose of this CPP proposal we have maintained our longer term targets at pre-earthquake levels. We believe this is consistent with the consultation feedback we received prior to the earthquakes, ie: that consumers were satisfied with those pre-earthquake levels of service. Our CPP proposal consultation feedback has also endorsed this view. This is described in detail in our CPP application.

Our long term SAIDI and SAIFI target is currently the same as that which we specified before the earthquakes, and reflects the current DPP limits which apply to us.

Over the next few years we will continue to evaluate our network performance and consult with our consumers over their service requirements. We expect we will refine our longer term targets as our network evolves to meet the changes in our supply area as Christchurch recovers and the rebuilding and relocation activities progress.

Network restoration

Consumers have consistently told us that if a power failure does occur, then rapid restoration of power is their most important concern. Our surveys have shown that 83% to 90% of consumers consider our response is important following a power failure. Consequently we have two measures relevant to this aspect of our service. These consumer focused measures are:

- CAIDI, consumer average interruption duration index, measures the average duration of an interruption to supply for those consumers who have experienced an interruption to supply
- the percentage of faults restored within three hours.

Prior to the earthquakes consumers told us that they were generally satisfied with our level of service and that they were concerned about increased electricity prices. In practical terms this means that before the earthquakes we concluded that our consumers did not wish to see increased levels of service if this would mean higher prices. Our CAIDI targets and the percentage of faults restored within three hours are based on providing a reasonable level of service at a reasonable cost.

As for our reliability targets, we have maintained our long term targets at pre earthquake levels. These may be refined in the interim as more information becomes available to us post earthquake. We have not set targets for the CPP regulatory period for the reasons set out above.

The policies of most relevance to our network restoration service targets are the same as those set out above in relation to network reliability.

Network capacity

Orion has a network security standard that was developed in consultation with external advisors and adopted in 1998. It is based on the United Kingdom's P2/6 which is the regulated standard for distribution supply security in the UK and is explained in more detail in Section 6.2.7.

Security of supply is the ability of a network to meet the demand for electricity in certain circumstances when electrical equipment fails. Security of supply differs from reliability. Reliability is a measure of how the network performs and is measured in the duration and frequency of interruption of supply to consumers.

During 2007 we reviewed our security standard to ensure it takes into account consumer preferences for the quality and price of service that we provide. As a result of our review and consumer consultation, our security standard was improved to better reflect the needs of our consumers. Our revised security standard resulted in slightly lower reliability for our outer-urban consumers and this reduced the need for future price rises.

The trade-offs between price and electricity supply reliability is a constant focus for us. Generally, the more we spend, the more reliable our community's electricity supply becomes. The trade-off is that the more we spend the higher our prices become, as we need to recover our costs. We seek our consumers' views on the price quality trade-offs and we aim to ensure that our network investment decisions reflect consumer preferences.

The most relevant policy document for network capacity performance is our AMP. This sets out our security of supply standards, and our network gap analysis which explains how the security of supply standards are expected to be met and maintained over the planning period. This process is discussed in more detail in Section 9.13.7 below.

Power quality

Power quality is defined by a group of performance attributes of the electricity power supply. Two of the most common and important power quality attributes that are mostly under our control are:

- the steady state level of voltage supplied to consumers
- the level of harmonics or distortion of voltage of the power supply.

The reason why these attributes are not completely under our control is because the power quality that is supplied to us by Transpower (and to it by generators) provides a baseline level of performance that we can only pass on to consumers. We contract with Transpower to provide a suitable level of power quality performance at each GXP.

We have undertaken a three year project to install power quality measurement equipment at selected sites throughout our distribution network. The aim is to undertake a long term survey to determine the power quality performance of our distribution network and how it changes over time. The measurement sites chosen represent the average and worst performing parts of our network over a variety of consumer types.

Steady state voltage

The range of steady state voltage supplied to consumers is mandated by regulation, as 230 volts ± 6%. We design and operate our network to meet this requirement. However, despite our efforts and usually due to unanticipated changes in consumer loads, some consumers will experience voltages outside these limits for some period of time. When a complaint is made, we investigate it. If the complaint is proven (the investigation shows that the non-complying voltage or harmonic originated in our network) we will upgrade our network to rectify the problem.

The level at which we have set our target for steady state voltage non-compliance (proven) is a pragmatic consumer-focused ratio of no more than one case per 2,500 consumers per year.

Harmonics/distortion

The allowable level of harmonics or distortion of the power supply provided to consumers is also covered by regulation. In most cases the consumers themselves have distorted their power supply, for example, by the use of electronic equipment. We provide an initial investigation service to measure the levels of harmonics or distortion and will determine whether other consumers are affected. If others are affected, we will require that the offending consumer rectify the problem. If no other consumers are affected, we will suggest suitable consultants who can offer a solution to the problems.

We use harmonic allocation methods defined in joint International Electrotechnical Commission (IEC)/Australian/New Zealand standards to determine acceptable consumer levels of harmonic injection. These allow each consumer to inject a certain acceptable amount of harmonic distortion depending on the strength of the power supply at their premises.

The level at which we have set our target for proven harmonics/distortion complaints is no more than one per 50,000 consumers per year. This target is based on historical Orion and international data.

The most relevant Orion documents for power quality include our Network Code (NW70.00.15) which sets out the technical requirements for our network. In addition external regulations are also relevant, as we must meet minimum standards as set out in the Electricity Regulations and the NZ Electrical Codes of Practice. These are consistent with the technical obligations included in our Delivery Services Agreement (DSA).

Although the IEC standards, Electricity Regulations and Codes of Practice set limits for voltage harmonic distortion compliance, they do not provide a method by which compliance can be achieved. During 2011, the Electricity Engineers Association (EEA) instigated a project with the Electric Power Engineering Centre at the University of Canterbury to develop a Power Quality Guideline. The guideline was to include a customer allocation methodology for maximum harmonic currents to achieve regulatory compliance. The resulting guideline (Power Quality (PQ) Guideline 2012) was presented at the 2012 EEA conference.

We have successfully applied the guidelines' recommended harmonic allocation methodology to the Synlait and Fonterra milk processing plants on our rural network and also with CCC pump sites on our urban network. We intend to modify our Network Code to enable harmonic compliance by following the EEA PQ Guideline.

Safety

Operating and maintaining an electrical network involves hazardous situations that cannot be eliminated entirely. We are committed to consultation and co-operation between management and employees to provide a safe, reliable network and a healthy work environment – we take all practical steps to see that our operations do not place our staff or community at risk. Maintaining a safe, healthy work environment benefits everyone and is achieved through co-operative effort.

Our objectives are to:

- provide safe plant and systems of work
- maintain appropriate systems to ensure worker and public safety
- ensure compliance with legislative requirements and current industry standards
- provide safety information, instruction, training and supervision to employees and contractors
- provide support and assistance to employees
- set annual goals and objectives, and review the effectiveness of policies and procedures
- take all practicable steps to identify and eliminate, minimise or isolate hazards.

Our target of zero accidents is the only prudent target we could have for this measure.

We have a number of policies which address safety for our employees, contractors and the public. These are listed in our overarching Document Control Policy NW70.50.03 and include:

- Health and safety policies (OR00.00.01 and 02)
- Health and safety management and safety management system manuals (NW70.00.16 and NW70.00.21)
- Network operation policies and procedures (including Minimum Safe Approach Distances (NW21.07.04) and Incident/Accident recording, reporting and investigation procedures (NW00.20.02 and NW26.10.01)
- Hazard identification policies (refer NW 70.50.03 – Section 9.4.2)
- Contract management policies (including NW72.00.01 – Health and Safety Checklist and NW72.11.02 – Working near the Orion network – competency))

Environment

We aim to be environmentally responsible. We have established a number of environmental sustainability policies and associated procedures. They include:

- Environmental Management Manual (NW70.00.08)
- Environment procedures (refer NW70.10.02 – oil and fuel, and NW70.10.06 – SF6 gas)
- Environmental risk register (NW70.10.06)
- Contract works environmental audit policy (NW73.10.18).

These policies are reviewed annually. Our environmental measures related to the operation of our network are:

- the amount of SF_6 gas lost into the atmosphere (as a percentage of the total volume in use on our network)
- the number of oil spills that are not contained by our oil containment facilities or mitigation procedures.

Our target for loss to the atmosphere of the insulating gas SF_6 is based on a percentage of the total volume of the gas in use on our network. The level is set by an undertaking we have signed with the Ministry of the Environment to comply with the “Memorandum of Understanding relating to Management of Emissions of Sulphur Hexafluoride (SF_6) to the Atmosphere”. In addition to this we have a policy not to purchase equipment containing SF_6 gas if a technically and economically acceptable alternative exists. The outcome of this policy is that our current use of SF_6 only applies to 66kV circuit breakers. We note that technical alternatives are emerging but prices have not yet settled at an acceptable level.

In respect to oil spills, we operate oil containment facilities and have implemented oil spill mitigation procedures and training. Our target of zero uncontained oil spills is the only prudent target we could have for this measure.

Economic efficiency

Economic efficiency reflects our level of asset investment and cost required to provide network services to consumers, and the operational costs associated with maintaining, managing and operating our assets.

We have historically reported financial efficiency measures to the regulator via information disclosures. These are modified from time to time as ID is refined. Current ID requirements place emphasis on capital expenditure and operational expenditure measures.

As financial efficiency is measured by the Commission as part of its ID regime, and as this must be specified to be consistent with the long term interests of consumers (as per the Part 4 section 52A purpose statement – which we have set out in Section 3) we have adopted the following measures:

- capital expenditure per annum per MWh of electricity supplied to consumers
- operating expenditure per annum per MWh of electricity supplied to consumers
- operating expenditure per annum per year end number of ICPs (connection points).

We aim to perform better than the New Zealand average.

Capacity utilisation ratio

This ratio measures the utilisation of transformers installed on our network. It is calculated as the maximum demand experienced on the network divided by the distribution transformer capacity on the network.

We aim to adopt good design and lifecycle management practices. We do not specifically target levels of capacity utilisation as these could result in incentives to design inefficiently, for example such targets could incentivise us to install long lengths of low voltage distribution or replace transformers early in their lifecycle due to shifts in load profiles. Accordingly, although we monitor this ratio, we do not have a specific target for it.

Load factor

Annual load factor is calculated as the average load that passes through a network divided by the maximum load experienced in a given year. We aim to optimise our load factor through the continuation and implementation of demand side management (DSM) initiatives as this indicates better utilisation of capacity in the network. Although we do not have a specific load factor target, we seek to implement all economic DSM initiatives as they arise. Our forecasts are shown in Section 9.8.4.

Energy loss

All electricity networks have energy losses caused mainly by heating of lines, cables and transformers. Electrical losses are natural phenomena that cannot be avoided completely and consequently retailers have to purchase more energy than is delivered to their consumers. Historically, electrical losses were derived from the difference between energy volumes entering our network at GXPs and the energy volumes leaving our network, as measured (and billed) at consumer connections. Prior to the separation of distribution from retailing, losses on our network were measured at 4.9%. However, structural separation has lead to inaccuracies and deficiencies in billing systems, and apparent losses have been measured as high as 10-15% in recent years.

There is some uncertainty in metered volumes because:

- metering errors occur at GXPs (approximately + 0.2%)
- metering errors occur at consumer connections (approximately + 2.5%)
- timing of meter reading is precise at GXPs (meters are read every half hour) but is imprecise at consumers' meters, which are read every one or two months
- the volume lost is the small difference between two large numbers that have uncertainties – approximately (+1%)
- metering data is subject to gaps and distortions due to incorrect multipliers being applied and omissions and errors when metering information is captured.

Consequently, we believe that our overall network loss ratio is 4.9% (± 1%). Significant deviations from this value exist in some parts of the network, for example, when we compare urban areas against rural areas.

When considering losses in network design and asset purchase, we do not aim for a target percentage of loss. Instead the lifetime annual cost of losses is converted to a net present capital value which can be added to the capital value of the asset concerned. We aim to implement the least cost overall (asset cost + capitalised loss cost) solution. This approach provides the lowest economic level of losses to aim for in our network and meets our contractual obligation to adhere to good industry practice.

9.6.5 Provide load management services

The provision of load management services is also covered by our DSA including specifically: C5 Provision of Ripple Signalling.

Key service features and specifications

Load management refers to the way we reduce electrical load on our network during periods of high or peak electrical demand, or during emergencies on our network, or when there's a capacity shortage on Transpower's grid.

We operate a ripple signalling system that allows us to send signals through the electricity network to ripple receivers at customers' premises. Remote signalling service is the function of providing a signal via the distribution network for the purpose of operating equipment on the connected consumer's premises (clauses 5, 6 and 7 of the DSA describe the services in more detail).

We provide a number of different signals to manage load in different ways:

- our peak control signals are sent out when load is peaking and ripple receivers on peak channels switch off appliances (mainly hot water cylinders) to help reduce the peak
- our fixed time control signals are sent out every day, turning appliances on (hot water cylinders and night store heaters) at times when our loading levels are always low
- our pricing signals provide incentives that reward retailers' consumers who lower the amount of electricity they consume during our high priced peak period. We provide ripple signals to notify consumers of a peak period so that they can reduce their load and reduce their charges – this arrangement is more useful for larger business connections with special half-hour interval metering that records the reduced loading level during the peak period.

We also provide a load management service for the Upper South Island. The service is designed around real time data from Transpower and the Upper South Island electricity distributors to a centralised controller, based in Orion's control centre. Eight distribution networks throughout the region are currently participating in the project. These networks are: Network Tasman, Marlborough Lines, MainPower, Orion, Buller Electricity, Westpower, Electricity Ashburton and Alpine Energy.

The service has two main objectives:

- to reduce demand during peak loading times
- to assist Transpower to maintain security of supply by using available load shedding capability across the Upper South Island to automatically reduce load if needed during grid outages.

Identity of the intended consumers of the services

Our ripple control activities are aimed at general connections, our pricing signals at major connections.

Process for determining the features and specifications of each service

Our website page http://www.oriongroup.co.nz/load-management/load-management-dashboard shows the features of each of our load management services. These services form part of our DSA, and hence the processes are the same as those outlined above in respect of our provider and operator infrastructure service.

Any material change to the services in the next period

There are no material changes to the services planned for the next period. Load management is an integrated part of our network operations, and as illustrated in Section 9.13.10 which explains our non network solutions, the impact of our peak demand capping has increased significantly since the early 1980s.

9.6.6 Service measures and targets for provide load management services

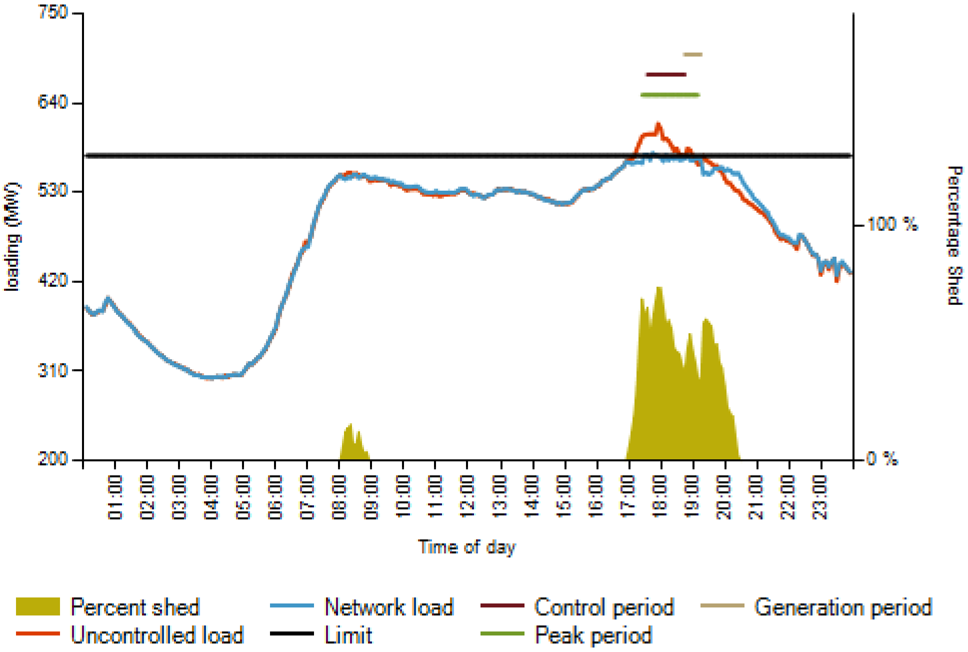
Provide load management services

Service description	Service measure	Next period targets	Long term targets
Supply interruption	Residential controllable load	Maximum of 4 hours off in any 8 hour period	
	Business controllable load	Maximum of 2 hours off in any 5 hour period	

Our load management primarily focuses on storage water heating, where supply can be interrupted for a period of time without affecting the availability of hot water. Our control simply delays the heating of water cylinders until the peak load or network constraint has passed. To ensure that consumers are not adversely affected by our load management activities, we agree a set of long term service level targets with electricity retailers. These targets limit the amount of load shedding we do, for example the current targets for residential hot water heaters is 'no more than 4 hours off in any 8 hour period'. We then aim to limit load (and therefore delivery costs and charges) to the maximum extent possible without breaching these agreed service level targets - this is a challenging cost/quality trade-off to achieve, and we actively report on our results, in real time on our website. Our website reporting includes:

- current loading and load management measurements for Orion's network
- trigger points and status of pricing periods
- Orion's network load and load management chart (refer example below for 13 August 2012)
- network load, upper South Island region load and temperature chart
- water-heating service performance
- residential shedding duration during previous 8 hours and history (refer extract below)
- business shedding duration during previous 5 hours and history (refer extract below).

Orion’s network load and load management – Monday 13 August 2012



Orion’s service levels and control parameter history (extract)

	Residential		**Business**	
	Measured over any 8 hour period		**Measured over any 5 hour period**	
Date	***Longest off***	***Highest average off***	***Longest off***	***Highest average off***
Agreed service level target: 'Residential: Maximum of 4 hours off in any 8 hour period'				
Agreed service level target: 'Business: Maximum of 2 hours off in any 5 hour period'				
Limit: '555MW' **Peak period on/off trigger:** '570MW / 555MW' **Control period on/off trigger:** '575MW / 560MW' **from 1 May 2012**				
Comment: 'Opening limits and triggers set as a base from which changes can be applied to the extent required to meet customer demand - adjustments aim to focus load management on the periods of highest loading, meet service level targets and achieve the target annual duration for pricing periods'				
01/05/2012	1:14	0:17	1:11	0:15
02/05/2012	0:41	0:31	0:39	0:30
03/05/2012	0:41	0:31	0:35	0:26
16/05/2012	1:10	0:54	1:10	0:55

9.6.7 Provide connection services

Connection services are provided in response to a request from an existing consumer or a potential consumer who wishes to connect to or modify an existing connection to our network. A fuller description of these services is set out in the following sections of the DSA:

- C2 New Connections
- C3 Modification of an Existing Connection
- C4 Temporary Isolations
- C11 Maintenance on Connected Customer’s side of Network Connection Point
- C13 Temporary Connections

Identity of the intended consumers of the services

These services apply to all existing or potential consumers wishing to connect or modify their connection. The consumers who seek the C2 and C13 services are often builders or property developers.

Process for determining the features and specifications of each service

Our DSA recognises that it may be necessary for us to upgrade our delivery services or extend our distribution network in order to respond to specific requests of consumers. The DSA acknowledges that we may enter into connection agreements with consumers for this purpose.

Our connections and extensions policy (NW70.00.45) states the commercial terms Orion applies for extensions to its network, for new connections in areas with existing supply, and for alterations to existing connections. This policy recognises that consumer specific circumstances need to be taken into consideration. Standard terms apply to broad categories of extensions and new connections. More specific considerations are made for other or larger connections which do not fit within these categories.

We endeavour to provide new connections and enhanced capacity wherever it is economically viable, and our network extension policy sets out to establish this economic viability. However, there may be situations where it is imprudent, environmentally unsound or physically impracticable to provide supply or enhanced capacity, and we reserve the right to refuse to provide new connections or enhanced capacity in these rare cases.

Any material change to the services in the next period

We are not planning any material changes to the services in the next period, although we note we are expecting an increase in connection activity in conjunction with the Christchurch rebuild and associated population relocation. This is described in Section 9.16.1.

9.6.8 Service measures and targets for provide connection services

Provide connection services

Service description	Service measure	Next period targets	Long term targets
Customer service	Prompt response to enquiries	No targets set to date	
	Approval for application for standard residential connection	To target approval within seven working days, although dependent on circumstance and information available	

We know that consumers want a quick response from us following an interruption to their electricity supply, and they want information on when it will be restored. We operate a 24/7 contact centre from our head office for this purpose. This contact centre is also a point of contact for connection services.

We are currently investigating alternative means to measure consumer satisfaction in this area of our service. This may include further surveys or call backs to consumers who have had recent contact with us. We hope that in the future we will be able to develop numerical targets around satisfaction with our contact centre.

We aim to address all requests for new connections, or asset relocations, as promptly as possible. As residential connections tend to be standard, we are able to set targets for responding to those within agreed time frames. Achieving this is dependent on the necessary connection information available and being able to contact the consumer in a timely way. We do not have service targets for responding to non residential connections. These are handled on a case by case basis because of the diverse nature of them.

Our most relevant policies for our connection service measures are:

- Connection management policies (refer NW70.50.03 – 9.6.1)
- Network connections and extensions policy (NW70.00.45)
- DSA.

9.6.9 Rearrangement of network assets at third party request services

Parties such as NZTA or CCC and SDC may request that we relocate assets (in order to accommodate roading projects) or replace overhead reticulation with underground cables. A fuller description of these services is set out in the following section of the DSA:

- C7 Network Plant Removal or Re-siting

Identity of the intended consumers of the services

While existing consumers may require existing assets to be located, it is more usual for such requests to arise from local councils, NZTA or property developers.

Process for determining the features and specifications of each service

Like customer connection services, our DSA recognises that it may be necessary for us to modify our network in order to respond to specific requests of external parties. Similar processes to those for new or modified connections are undertaken for asset relocations. Once again there are location specific circumstances which must be taken into consideration. These are developed in consultation with the initiating party, typically the local council, NZTA or developers. Where possible we integrate our relocation projects with other works planned in that location to minimise disruption to consumers and the wider community.

Any material change to the services in the next period

We are not planning any material change to the services in the next period, although we note that the Christchurch rebuild has impacted on the CCC’s undergrounding programme. These services are provided in direct response to consumer demand, as reflected in our expenditure forecasts. These are described in Section 9.16.1.

9.6.10 Service measures and targets for rearrangement of assets at third party request

As these services are provided on a case by case basis, we do not have specific measures and targets for this service.

Our most relevant policies for asset relocation services are:

- Underground conversion policy (NW70.00.10)
- DSA.

9.6.11 Determining service targets

Our service level targets are based on a balance of:

- consumer and stakeholder consultation
- safety
- regulatory requirements
- international best practice and good industry practice
- past practice
- cost
- extraordinary events and their impact on what is practicable to achieve (for example the recent earthquakes).

We aim to provide a level of service that meets the long term interests of our consumers. This is particularly challenging where the end use of electricity is changing relatively rapidly compared to the lifetime of distribution network assets. It is foreseeable that the role of the distributor will change over the next 50 years and flexibility where possible will be valued by our consumers. We recognise the differing requirements of consumers and endeavour to ensure that, as far as practicable, all consumers are satisfied with the level of service we provide and that no one party is unfairly advantaged or disadvantaged.

Keeping abreast of changing consumer needs and expectations is fundamental to optimal asset investment and asset management practices and hence providing appropriate levels of service. In order to determine consumer expectations with regard to the level of service that we provide, we use five main methods of consultation. In summary, we:

- involve consumers in setting our security of supply standard
- undertake consumer surveys
- engage with consumers via retailers
- obtain direct consumer feedback
- consult consumers on selected major projects.

In setting our service level targets we believe we have achieved an appropriate balance between legislative, regulatory and stakeholder requirements and consumer expectations.

Consumer consultation

Consumers are one of our key stakeholder groups. We recognise that their individual expectations will differ and we endeavour to ensure that, as far as practicable, all are satisfied with the level of service we provide in the long term. Past consultation with our consumers has shown that they expect a reliable and secure supply of electricity. They have expressed satisfaction with historical levels of service, ie: they expect no major changes to in service levels.

Our consumer consultation methods are described below.

Consumer surveys

Over the last 10 years, five direct consumer surveys have been undertaken by Orion (pre earthquake). These are summarised in the following table.

Consumer surveys

Survey	Year	Description
Research into the strengthening of relationships with landowners	FY03	We undertook telephone interviews with a random sample of 30 rural landowners who had had contact with us during the previous year. The results indicated that the majority of rural landowners were satisfied with the quality of our products and services. Of those who were dissatisfied in some way, a ratio of two to one landowners expressed a preference for an increase in reliability as opposed to a decrease.
Network reliability consumer survey	FY04	We commissioned independent researchers to conduct a telephone survey with approximately 1,000 households in the Christchurch area. This survey indicated that 92% of respondents were satisfied with the current reliability of their power supply while 87% considered rapid restoration of power important.
Urban and rural network reliability consumer survey	FY06	We commissioned an independent research company to survey a random sample of 400 rural and 400 urban households in our network area. This survey indicated that: • 94% of urban respondents were satisfied with the current reliability of their power supply while 88% considered rapid restoration of power important • 85% of rural respondents were satisfied with the current reliability of their power supply while 83% considered rapid restoration of power important • of those surveyed, 99% of urban respondents and 98% of rural respondents were not prepared to pay more for improved supply reliability.
Snow storm survey	FY07	We commissioned an independent research company to survey a random sample of over 400 rural consumers. This survey

		focused on consumer attitudes and opinions to our response to the severe snow storm in June 2006: • the survey captured consumers that lost power (245 respondents) and those that did not lose power (170 respondents) during the storm • unsurprisingly, the overall level of satisfaction with reliability of rural power supply fell slightly in this survey from what it had been in late 2005 • of the survey respondents, 76% were satisfied with the reliability of their power supply compared to 85% in 2005.
Rural consumer reaction to paying for greater reliability	FY08	We commissioned an independent research company to survey a random sample of 400 rural residential consumers. The focus of this survey was to determine whether consumers were willing to pay more for increased reliability. Potential improvements in reliability could be gained by reducing outages through introducing the Ground Fault Neutraliser (GFN) technology on the rural overhead medium voltage network. The survey indicated 68% of our residential rural consumers would be willing to pay ($1 per month) more for: • reductions in the number of lengthy power cuts • elimination of momentary one or two second interruptions Those consumers not willing to pay more tended to be older, have smaller electricity bills and those which had experienced fewer lengthy power interruptions within the last six months. If the cost was reduced to 50c per month, an additional 6% (74% in total) in total were willing to pay for improved reliability.

Engagement with retailers

On a daily basis, electricity retailers represent the consumers connected to our network. We therefore expect retailers to let us know how consumers feel about the price and quality of our network service. Based on our interactions with retailers, we are not aware of any material systemic concerns with the level of reliability we provide. In addition we have agreed hot water heating service targets (peak load shedding) with retailers.

Direct consumer feedback

All of our major consumers are invited to at least two Orion seminars a year. At these seminars we take the opportunity to explain the quality of our delivery service and our pricing strategy. Our senior management team attends the seminars to answer any questions from major consumers. In addition we meet with our shareholders and other consumer groups each year to discuss the quality and price of supply we provide. Feedback is also received from consumers through our contact centre and distribution services connection group.

Consumer consultation over service level changes, major projects and connection arrangements

During our 2007 changes to our security of supply standard we consulted with Retailers, the Major Electricity Users Group, Grey Power and Canterbury Manufacturers Association. These consumer groups agreed to a slightly lower level of reliability in our outer urban areas in exchange for downward pressure on price.

We consult with various parties ranging from local councils to business and residential groups about selected major projects that we undertake. This consultation includes discussion about the benefits and costs of specific projects. For example, we consulted with the SDC and Izone (industrial subdivision developers in Rolleston) regarding the timing and extent of security and reliability enhancements to the wider Rolleston area. Our consultation informed these groups of the important factors including the historic rural nature of the Rolleston township, the timing of subtransmission investments to match load growth and the impact of undergrounding 11kV.

During 2004 and 2005 we consulted with a representative group of farm irrigators on the appropriateness of using irrigation pumps as an interruptible load during rare but major network contingencies. This consultation was informed by an Agri Business report on the value of water to farms. This consultation confirmed the appropriateness of reduced network infrastructure with irrigation pump interruptibility in exchange for a rebate.

We also consult with major customers during the design phase of major asset replacement work in the area. This provides major customers with an opportunity to reconsider the service versus cost trade-off.

Post earthquake consultation

Our consultation post earthquakes, as summarised in our CPP application, involved communication about our draft proposed network plans and reliability and price impacts using the following means:

- engagement briefings with key stakeholders (Ministers, Canterbury Employers, local councils, CCHL, Connetics, Canterbury Manufacturers, Ngai Tahu, The Press, Welfare Agencies, North Island retailers
- discussions with EA, Treasury, MEUG, Business NZ, Environment Canterbury, CERA, Wider Earthquake Communities Action Network
- written communication with Senior Citizens, Electricity and Gas Complaints Commissioner, Domestic Energy Users Network, Rural Women NZ, Age Concern, Public Health Association, Child Poverty Action Group, Grey Power, Federated Farmers
- newspaper advertisements
- radio interviews
- major customer seminars
- public information day
- website information and twitter social media.

9.6.12 Performance against service targets

The following tables summarise our actual performance against our targets for each of our service measures, for the current period (FY08 to FY12).

Service – provide and operate network infrastructure

Review of network reliability

Network reliability performance

Measure		Target	Actual	Explanation
SAIDI	FY08 FY09 FY10 FY11 FY12	< 63 < 63 < 59.7 < 59.7 < 59.7	45 62 61 3,815 231	Actual performance reflects year on year variability due to the impact of major external events such as storms, and more recently earthquakes. The "normalised" result after the application of the DPP MED method is 108 SAIDI minutes for FY11 and 134 for FY12.
SAIFI	FY08 FY09 FY10 FY11 FY12	< 0.76 < 0.76 < 0.78 < 0.78 < 0.78	0.63 0.60 0.58 3.05 2.22	As above. The earthquake impacts are evident in FY11 and FY12. When normalised using the DPP MED method annual SAIFI reduces to: 1.44 for FY11 and 1.90 for FY12. The catastrophic nature of these events is not fully addressed through the MED methodology.
Faults per 100km HV Circuit	FY08 FY09 FY10 FY11 FY12	< 11.0 < 11.0 < 11.0 < 11.0 < 11.0	7.3 8.7 6.7 21.0 15.8	The impact of the earthquakes is clearly illustrated in our faults data for FY11 and FY12. Our performance in the prior years was well within our targets.
Faults per 100km 66kV circuit	FY08 FY09 FY10 FY11 FY12	< 2.0 < 2.0 < 2.0 < 2.0 < 2.0	1.0 1.0 0.5 5.5 2.9	We out-performed our targets prior to the earthquake years.
Faults per 100km 33kV circuit	FY08 FY09 FY10 FY11 FY12	< 4.0 < 4.0 < 4.0 < 4.0 < 4.0	6.4 3.4 2.4 4.5 1.2	A major 33kV outage caused us to exceed our target in FY08. Otherwise we out performed our targets in all other years with the exception of FY11 which included the September 2010 and February 2011 earthquake.
Faults per 100km 11kV circuit	FY08 FY09 FY10 FY11 FY12	< 12.0 < 12.0 < 12.0 < 12.0 < 12.0	7.6 9.3 7.2 22.5 17.1	Once again we out-performed our targets in the years prior to the earthquakes.

Interruption data recorded in our control centre provides all relevant statistical data needed to calculate our reliability statistics using the international measures of SAIDI, SAIFI and CAIDI. More information on our network performance can be found in our network quality report on our website oriongroup.co.nz.

It is important to note that one-off factors such as bad weather and earthquakes can heavily influence the results in any one year although since FY11, regulatory SAIDI and SAIFI measures include normalisation to cap the impact of extreme events.

Our network has generally improved over the 20 years that we have compiled detailed reliability statistics. Statistics from the first few years indicate that most interruptions occurred in the rural area and were due to trees on lines, vehicles hitting poles and equipment failure to a lesser extent. Since then we have made considerable effort to control tree growth and instigate various maintenance programmes on our rural 11kV lines. A project to install reflectors on roadside poles to reduce the incidence of vehicles hitting poles has also been completed.

Our plant failure statistics show that as loads increase in parts of our network, we have to work harder to keep aging equipment performing satisfactorily. We now use a UV corona imaging camera in a cost-effective move that utilises the latest technology in an effort to identify potential problems before they cause an interruption.

We have also completed a project to shorten the interrupted portions of our feeders by installing additional line circuit breakers. Circuit breakers are relocated to more appropriate locations as the network is altered.

We have installed and put into service a number of GFNs. These units are equipped with fifth harmonic residual current compensation and are starting to contribute to an improvement in rural network reliability and safety. The balance of the GFNs is expected to be in service by March 2014.

Our FY11 reliability results were overwhelmed by earthquakes in the Christchurch and Central Canterbury region. Five aftershocks between M5.3 and M6.4 and two significant snowstorms combined to make FY12 another difficult year. We expect it will take at least until the end of the CPP regulatory period to fully restore our network to its pre-earthquake reliability levels.

Service – provide and operate network infrastructure

Review of network restoration

Network restoration performance				
Measure		**Target**	**Actual**	**Explanation**
CAIDI	FY08 FY09 FY10 FY11 FY12	< 83 < 83 < 90 < 77 < 90	72 103 106 1,252 104	We have not met our CAIDI targets since FY09. We had more planned outages than expected in FY09 and FY10, which tend to be of a longer duration than unplanned outages. Our performance in FY11 and FY12 reflects the earthquake impacts.
Faults restored within 3 hours	FY08 FY09 FY10 FY11 FY12	> 60% > 60% > 60% > 60% > 60%	72% 92% 92% 41% 67%	We have exceeded our targets in all years but FY11.

Service – provide and operate network infrastructure

Review of network capacity

Our security standard provides a useful benchmark to identify areas on our network that may not currently receive the high level of security that the majority of our network has. Any gaps against our security standard are discussed in Section 9.13.7 below.

Service – provide and operate network infrastructure

Review of power quality

Power quality performance				
Measure		**Target**	**Actual**	**Explanation**
Steady state level of voltage	FY08 FY09 FY10 FY11 FY12	< 70 < 70 < 70 < 70 < 70	17 28 34 51 35	We have out-performed our targets in all years for this measure.
Level of harmonic Distortion	FY08 FY09 FY10 FY11 FY12	< 2 < 2 < 4 < 2 < 4	0 0 0 0 0	We have also out performed our targets for this measure for all years.

Our main objective in relation to power quality is to identify and resolve consumer quality of supply enquiries. To achieve this we fit test instruments close to the point where ownership changes between our network and the consumer's electrical installation. Data gathered from the test instruments is analysed against the New Zealand Electricity Regulations 1997. By applying key regulations in relation to voltage, frequency, quality of supply and harmonics we are able to determine which quality problems have originated within our network. Our network performs well in terms of voltage and quality. We receive a number of voltage complaints every year but only approximately 30% of complaints are due to a problem in our network. In the table above, 'proven' means that the non-complying voltage or harmonic originated in our network.

Service – provide and operate network infrastructure

Review of safety

Safety performance				
Measure		**Target**	**Actual**	**Explanation**
Safety of employees and contractors	FY08	0	0	Despite our best efforts we have recorded lost time accidents/injuries during the current period. We continue to demand safe work practices of our staff and contractors to achieve our target of 0 incidents each year.
	FY09	0	7	
	FY10	0	2	
	FY11	0	9	
	FY12	0	3	
Safety of public	FY08	No target	-	In FY09 a member of the public suffered minor injuries on a work site after the theft of a trench-cover. We continue to promote safe habits around our assets to achieve our target of 0 incidents.
	FY09	0	1	
	FY10	0	0	
	FY11	0	0	
	FY12	0	-	

Service – provide and operate network infrastructure

Review of environmental performance

Environmental performance				
Measure		**Target**	**Actual**	**Explanation**
SF_6 gas lost	FY08	< 1%	< 1%	We have out-performed our targets for this measure for all years.
	FY09	< 1%	< 1%	
	FY10	< 1%	< 1%	
	FY11	< 1%	< 1%	
	FY12	< 1%	-	
Oil spilt	FY08	0	0	Our historical record is good for this measure. We incurred some damage to our 66kV oil filled cables during the September 2010 earthquakes which resulted in spills in the FY11 year.
	FY09	0	0	
	FY10	0	1	
	FY11	0	9	
	FY12	0	-	

Service – provide and operate network infrastructure

Review of economic efficiency

Economic efficiency performance

Measure		Target	Actual	Explanation
Capex per MWh electricity supplied	FY08	< 15.7	11.5	We have met our capex efficiency target in all years of the current period. FY12 data which forms the basis of our target is not yet available.
	FY09	< 17.8	11.0	
	FY10	< 15.9	12.9	
	FY11	< 17.6	10.6	
	FY12	[n/a]	17.5	
Opex per MWh electricity supplied	FY08	< 13.1	11.3	We also met our opex efficiency targets in all years of the current period. As above, industry wide FY12 data is not available at this stage, so we are unable to derive our target.
	FY09	< 13.9	11.6	
	FY10	< 14.2	12.5	
	FY11	< 14.8	14.1	
	FY12	[n/a]	17.4	
Opex per annum per year-end number of ICPs	FY08	< 204	192	We did not meet our opex target in FY11. We anticipate that the abnormal costs we incurred as a result of the earthquakes will have been the major contributor to this result.
	FY09	< 211	199	
	FY10	< 221	213	
	FY11	< 228	242	
	FY12	[n/a]	280	
Capacity utilisation Ratio	FY08	No target set	37.5	Our capacity utilisation ratio remains above 30% in all years of the current period.
	FY09	No target set	36.0	
	FY10	No target set	31.4	
	FY11	No target set	30.9	
	FY12	No target set	31.5	
Load factor	FY08	No target set	60.1	We always seek to optimise load factor as this indicates better utilisation of capacity in the network. Load factor has trended upwards over the last 15 years by just over 0.7% per annum
	FY09	No target set	62.0	
	FY10	No target set	63.4	
	FY11	No target set	61.3	
	FY12	No target set	55.2	
Losses (%)	FY08	No target set	< 5	Overall, losses do not impact significantly on how we design and operate our network – other factors tend to dominate. Losses are significant in some aspects of network design though, and require policies for optimisation
	FY09	No target set	< 5	
	FY10	No target set	< 5	
	FY11	No target set	< 5	
	FY12	No target set	< 5	

These network-wide utilisation measures are greatly influenced by consumer decisions, such as the need for irrigation capacity. While we monitor our performance against these industry standard measures, they inherently reflect the characteristics of the consumers we serve. While heat pumps are an efficient form of heating they will most likely be running during cold periods, which adds to our peak load.

With respect to energy losses, the following are additional significant points:

- it is difficult to determine electrical losses

- losses occur mostly in lines and cables (3.3%) and transformers (1.7%)
- a trade-off exists between capital and loss costs, which results in optimisation of losses, not minimisation
- we give specific consideration to losses when purchasing transformers
- we optimise losses on the 11kV underground network by applying our economically derived security of supply standard to reinforcement
- we consider loss optimisation when we design and operate overhead lines in areas with high loading density; elsewhere, other factors determine how we select conductor size
- for any major network development, we consider the cost of losses
- some other minor contributors towards losses – internal use, unmetered supplies and theft – have little impact on our overall network losses.

Service – provide load management services

Review of hot water heating service levels

The following table summarises our load management service level performance over the past five years.

Load shedding duration			
Year end 31 August	**Duration of load shedding (hours on n days)**	**Number of days on which our target service levels were not met**	**Average hours of load shedding in excess of service levels on days when levels not met**
FY08	60 hours over 66 days	2	0.9
FY09	173 hours over 89 days	19	1.5
FY10	103 hours over 102 days	4	1.1
FY11	169 hours over 98 days	12	2.1
FY12	90 hours over 84 days	None	n/a

We do not believe that the excess shedding shown in the above table is material.

Ongoing failure to meet target service levels would have two effects. In the short term, consumers would have inadequate hot water and be dissatisfied and in the longer term consumers would be less likely to choose pricing options that allow peak load management, leading to inferior economic outcomes.

We do not receive a high number of hot water complaints from consumers, and we have not observed any material change in the response to our load management signals.

Service – provide connection services

Review of customer service

We aim to answer telephone calls from consumers promptly. Approximately 92% of calls to our contact centre are answered within 20 seconds, with an average wait time of about 11 seconds. However, our focus on call management is not on call answering times, or call duration, but rather receiving and providing information quickly, accurately and politely.

Although our target is for approval within seven working days for a standard residential connection, we currently do not monitor or report our performance against this measure.

Service – provide relocation services at third party request

As stated earlier, we do not have service measures or targets for this service, as these services are provided in response to third party requests and, because of their variability, are addressed on a case by case basis.

9.7 Lifecycle plans

9.7.1 Establishing asset lifecycles

We undertake lifecycle management and asset maintenance planning using whole of life cost analysis, reliability-centred maintenance (RCM), condition based maintenance (CBM) and risk management techniques. The techniques are based on our performance and reliability targets. More information on our service targets and measures is set out above in Section 9.6.

We have developed a RCM culture generally based on retaining the functionality of assets. To do this we ask the following questions:

- what is the functional requirement of this asset?
- what is it that may fail and prevent this asset functioning as required?
- what is required to retain the asset's functionality?

Asset monitoring is a key component of this approach. We use information gathered through routine monitoring and during planned and unplanned outages to assist us in this process.

CBM is an extension to RCM. Where appropriate, maintenance is performed based on the condition of the asset, rather than on the traditional time-based approach. We continue to assess and proactively replace network equipment that is nearing the end of its life expectancy. This assessment is carried out using a risk based approach and by looking at whole-of-life cost. The risk based approach is based on three characteristics of failure – frequency, consequence and context.

We have recently engaged EAT to develop Condition Based Risk Management (CBRM) models for the majority of our network assets. This is part of our development of a condition based approach to lifecycle asset management. This is discussed further below in Section 9.15.

9.7.2 Description of our network distribution area

Our network supply area is illustrated in the following map. It comprises one geographically contiguous network.

Large customers

Canterbury business sectors are largely service and/or agricultural based. This is reflected in the mix of approximately 320 major business customers connected to our network with loads ranging from 0.3MW to 5MW. The largest single load in this category is less than 1% of our total maximum demand.

Currently we have 20 major consumers which have an anytime maximum demand of greater than 2MVA. These consumers are represented in the following activities:

- food processing (5)
- meat works (3)
- industrial (4)
- hospital (2)
- university (2)
- airport/seaport (2)
- shopping mall (2).

Each of these major consumers is charged on a 'major customer connection' delivery charge basis. Individually, we discuss their security and reliability of supply requirements in relation to our normal network performance levels at the time of connection or upgrade. Generally our operating regimes and asset management practices do not specifically provide enhanced levels of service for these consumers.

We run six monthly seminars to update our major consumers and provide them with a forum for open discussion. Typically we discuss asset management priorities, enhancement projects and current industry issues. We explain and promote pricing options including demand side management and power quality.

If major consumers require enhanced network performance, we work with them to achieve their requirements by either enhanced connection or on-site generation options. Our delivery pricing allows for charges for dedicated equipment for enhanced supply to be made or incentives if the running of embedded generation benefits our network.

Many major customers run generators in response to our pricing signals and we have specific arrangements to run generators at approximately 40 connections at other times when it is beneficial for our delivery service (see Section 9.13.9 for details of our DSM initiatives). Connected generation at consumer sites can vary from a few kilowatts to as much as 2.5MW. We have 19 connections with more than 1MVA installed capacity.

Although there are issues to be co-ordinated when sites with generation are established, there is minimal impact on the operation and asset management of the local area networks. Most of these sites have installed generators for security reasons and running of the generators generally only reduces or off-sets their established load requirements. A small number of sites have the ability to export surplus energy into the network with metering and protection systems appropriately installed. The largest net energy export into the Orion network is 1.2MW.

As part of obligations under the Civil Defence and Emergency Management Act we have ongoing discussions with life-line services such as the hospitals, seaport and airport to ensure appropriate levels of service are provided for in our future planning.

Two rural milk processing plants have a significant impact on our network operations and asset management priorities.

The Synlait plant located at Dunsandel was livened in July 2008. Its load, including the predicted expansion, was significant in the context of our rural network design in that area. The installation required a new zone substation at Dunsandel providing enhanced security.

Similarly, the Fonterra plant commissioned during 2012 also required a new zone substation (Kimberley) to provide enhanced security. This has required us to revisit proposed current and future rural network design in Darfield and the surrounding area. Both connections are part of a ‘large capacity connection’ category to accurately reflect the cost of supply to this type of connection. The ongoing delivery charges reflect an appropriate return on the assets needed to supply electricity to these consumers.

One consumer group that significantly impacts on the operation and asset management of our network is agricultural irrigation in the rural area. Its growth over the last 15-20 years has required substantial reinforcement of our network. In discussions with this consumer group, we were able to determine that as a group they could endure a slightly reduced level of security of supply. To reduce our investment in the rural network, we were able to offer an appropriate pricing scheme for irrigation connections that allows us to control/turn off their irrigation during network emergencies.

Irrigation connections are also impacting on our rural network power quality. We have observed increased and excessive harmonic levels generated by non-linear control devices (variable speed drives) associated with the irrigation pumps. This has led us to undertake a power quality monitoring project and also to introduce new requirements for limiting harmonics generated from new connections.

Load characteristics

Urban load characteristics

Our urban load is made up of predominately residential winter peaking connections but also includes commercial and small scale manufacturing and industrial connections. Growth in peak demand and energy usage has been modest with pre earthquake growth rates in the 1-2% range.

The Canterbury earthquakes significantly affected the CBD commercial load and the residential load in the eastern suburbs. This has significantly (by approximately 10%) reduced our urban network peak demand and urban energy consumption. Post earthquake we are expecting a return over time to pre earthquake growth rates. We do not anticipate a change in the load demographic although new commercial buildings are expected to be more energy efficient than the old CBD stock.

At present there are no major single point load applications to consider on the urban network although from time to time we do receive preliminary applications for large data centres or other similar load.

Rural load characteristics

In contrast to our urban area, growth rates for our summer peaking rural areas have been high over the last 10 years largely due to the rapid growth of the dairy industry.

Since FY02, consumer applications to connect new load to our rural network have been reasonably consistent. However, the yearly variations in weather and in particular low summer rainfall resulted in an increase of 12MW and 7MW respectively across Hororata and Springston GXPs during the summers of FY04 and FY08. This demonstrates how variable peak loads can be, and how weather dependent they are – a dry summer in the Canterbury Plains causes an increase in peak demand as irrigation is required simultaneously across a large area.

Recently some irrigators with large ground-water irrigation schemes have installed surface river-take schemes in parallel with their existing schemes. These surface water schemes require a much smaller electric pump than the equivalent ground-water schemes, but are highly dependent on river flows and rain in the river catchment areas.

Irrigation load growth is expected to slow in the medium term as restrictions on the availability of ground-water take effect and more farms convert from ground-water to surface-water pumps. A 2010 Aqualinc study indicates the net result for most of our substations is no further growth due to irrigation loads. The exceptions are Dunsandel with a 7MW increase and Killinchy with a 1MW increase.

A second drier at the Synlait milk processing plant near Dunsandel was commissioned in 2012 and a third drier is proposed with a forecast total estimated load of approximately 8MVA at Synlait in FY14.

The new 4.5MVA Fonterra milk processing plant near Darfield was commissioned in FY12 and a second drier is proposed for FY13 with a total forecast Fonterra load of approximately 9MVA. We are in the process of contracting with Transpower for a new 66kV GXP at Kimberley in FY13.

Westland Milk Limited is also proposing driers in Rolleston. A significant proportion of the approximately 50% forecast increase in rural peak demand over the next 10 years is due to the increase in milk processing capability.

Total peak demand (urban and rural) and electricity delivered (historical)

The following table provides five years of peak demand and energy consumption history.

Total network demand and energy

Year	Peak demand excluding DG (MW)	Energy excluding DG (GWh)
FY08	631	3,320
FY09	623	3,398
FY10	615	3,427
FY11	613	3,305
FY12	629	3,064

Peak demand varies year by year depending on the severity of the winter weather and underlying growth. Prior to the earthquake, growth in peak demand and energy had been relatively modest with growth rates in the 1-2% range.

FY11 was partly affected by the 22 February 2011 earthquake with only a modest drop in energy consumption. Peak demand for FY11 (winter 2010) was down slightly due to a mild winter and was not affected by the earthquake.

FY12 was the first full year to be affected by the earthquake with energy down by approximately 10%. The winter of 2011 (FY12) included a severe snow storm and although demand on a typical winter day has dropped, the severity of the snow storm resulted in peak demand reaching pre earthquake levels.

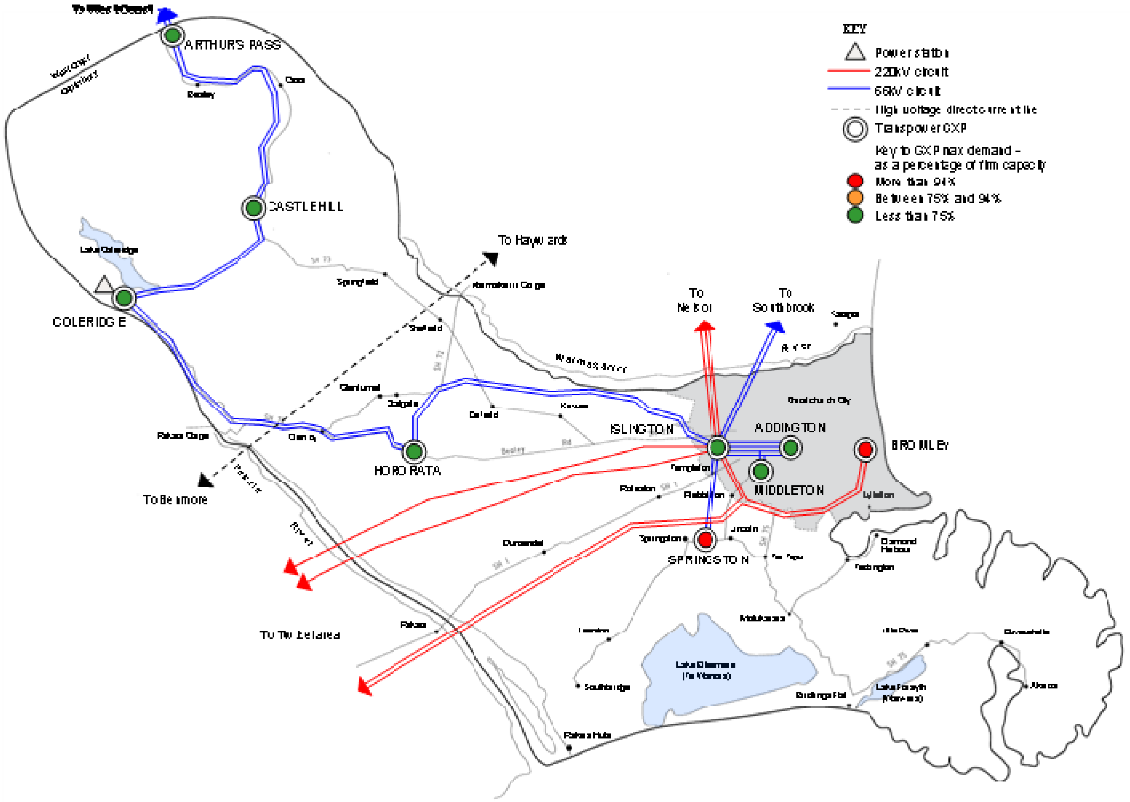
Energy consumption during the partially completed FY13 year is tracking similar to the FY12 year and despite another snow storm in FY13 (winter 2012) peak demand is down to 577MW which is consistent with the reduced post earthquake energy volumes.

9.7.3 Network configuration

Our network is supplied from nine GXP substations – four in the Christchurch urban area, two on the rural plains and three remote GXPs at Arthur's Pass, Coleridge and Castle Hill. Our network is fully contiguous.

The three remote GXPs each have a single transformer and much lower throughput of energy. With the exception of Hororata and Springston, all of the GXPs peak in winter.

These GXPs (shown in the following figure) supply over 99.8% of the electricity distributed to our customers, with the remainder coming from distributed generation powered by diesel or biogas. There is no embedded generation for bulk electricity supply.



Apart from the 66kV supply at Bromley and the 33kV supply at Islington, all other GXPs depend on the Islington 220/66kV interconnection made up of two 200/266MVA transformers and one 250/310MVA transformer.

Transpower charges EDBs, for example Orion and MainPower, for the costs to upgrade and maintain the GXPs. Orion owns all the assets connected to the GXPs and must plan the connection assets and ensure that any capex at the GXP is cost effective.

Urban GXPs are located at Islington, Addington, Middleton and Bromley substations. Islington supplies a 66kV and 33kV grid connection. Addington and Bromley supply both 66kV and 11kV grid connections and Middleton supplies a 66kV grid connection only.

Islington and Bromley 220kV substations form part of Transpower's South Island grid. They interconnect between the major 220kV circuits from the southern power stations. Addington and Middleton GXPs are supplied by 66kV lines from the Islington 66kV bus.

The Addington 66kV busbar is operationally split into two bus sections to improve reliability for consumers. We have implemented a similar bus zone protection scheme at Bromley.

We take connection from five rural GXPs. The two main ones are located at Springston and Hororata. Each GXP is supplied via a double 66kV line from the Islington 66kV bus. Hororata and Springston supply Orion at both 66kV and 33kV. Hororata is also connected to the West Coast via 66kV lines from the Coleridge power station.

The remainder of the rural area is fed at 11kV from three small GXPs at Arthur's Pass, Coleridge and Castle Hill. Together these supply less than 1% of Orion's load. Each GXP is fed from the 66kV Coleridge – West Coast lines.

Existing capacity and peak load at each bulk supply point

The following table shows the peak load at each bulk supply point from November 2011 to October 2012, and the firm capacity. With the exception of Arthur's Pass, Castle Hill and Coleridge which are single transformer sites, the firm capacity is the capacity of each site should one item of plant fail.

Supply point characteristics

Bulk supply point	Peak load (MVA)	Firm capacity (MVA)
Islington	372.0	532
Addington/Middleton	175.0	375
Bromley	142.0	130
Springston	57.0	57
Hororata	44.0	40*
Castle Hill	0.8	4
Arthur's Pass	0.4	3
Coleridge	0.4	4

* if Coleridge is not generating

Note that the Papanui GXP was decommissioned on 31 July 2012 when we purchased it from Transpower. Approximately 30,600 ICPs were reassigned to Islington and 1,900 ICPs transferred to Bromley.

Description of subtransmission system including voltage, capacity of each zone substation

We reviewed our Christchurch subtransmission network after the earthquakes. As a result, we have changed our design for future work from zone substations being radially fed from GXPs to a more resilient meshed layout.

Future design will be based on a closed-ring topology so that failure of any single route will not interrupt supply to a zone substation. Cables will be sized to give sufficient cross-GXP link capacity to provide full support in the loss of either Islington or Bromley 66 kV supply.

We have fourteen urban 66/11kV zone substations, five urban 33/11kV zone substations and eleven 11kV zone substations (with no transformer).

We can connect most new loads to our urban network at short notice, as required by consumers. The additional load makes use of network capacity held in reserve for contingency situations. That capacity must be replaced by capital expenditure in order to ensure that supply security continues to meet our security standard and the needs of our consumers.

Each increment of between 20MW and 40MW of new load requires a new zone substation. Zone substations supply an area close to them and free up capacity in adjacent substations. New zone substations require a suitable site, transformers, switchgear and subtransmission connected to Transpower's 66kV or 33kV GXPs.

We have six rural 66/11kV zone substations and 16 rural 33/11kV zone substations. Each increment of between 5MW and 10MW of new load requires a new zone substation. Zone substations supply an area close to them and free up capacity in adjacent substations. New zone substations require a suitable site, transformers, switchgear and subtransmission connected to Transpower's 66kV or 33kV GXPs.

Our existing rural subtransmission network has been designed to meet strong load growth, while optimising cost. The significant increase in load over the last 10 years has enabled a much more interconnected subtransmission network to be developed.

The number of zone substations operating in radial configuration has reduced over time. Most sites have only one transformer but the larger townships such as Rolleston and Lincoln have duplicated transformers. Transformers are generally 7.5MVA or 7.5/10MVA capacity.

Rural subtransmission capacity is generally limited by voltage drop considerations and hence 66kV (as opposed to 33kV) is technically and economically more attractive for new subtransmission projects.

The following table shows the peak load at each zone substation from November 2011 to October 2012, the firm capacity, the voltage supplied to the site and the class from our security of supply standard (included in Section 6.2.7). The security of supply standard is supported by the 66kV and 11kV network architecture reviews carried out in 2012 (included in appendices 6 and 7).

Zone substation characteristics

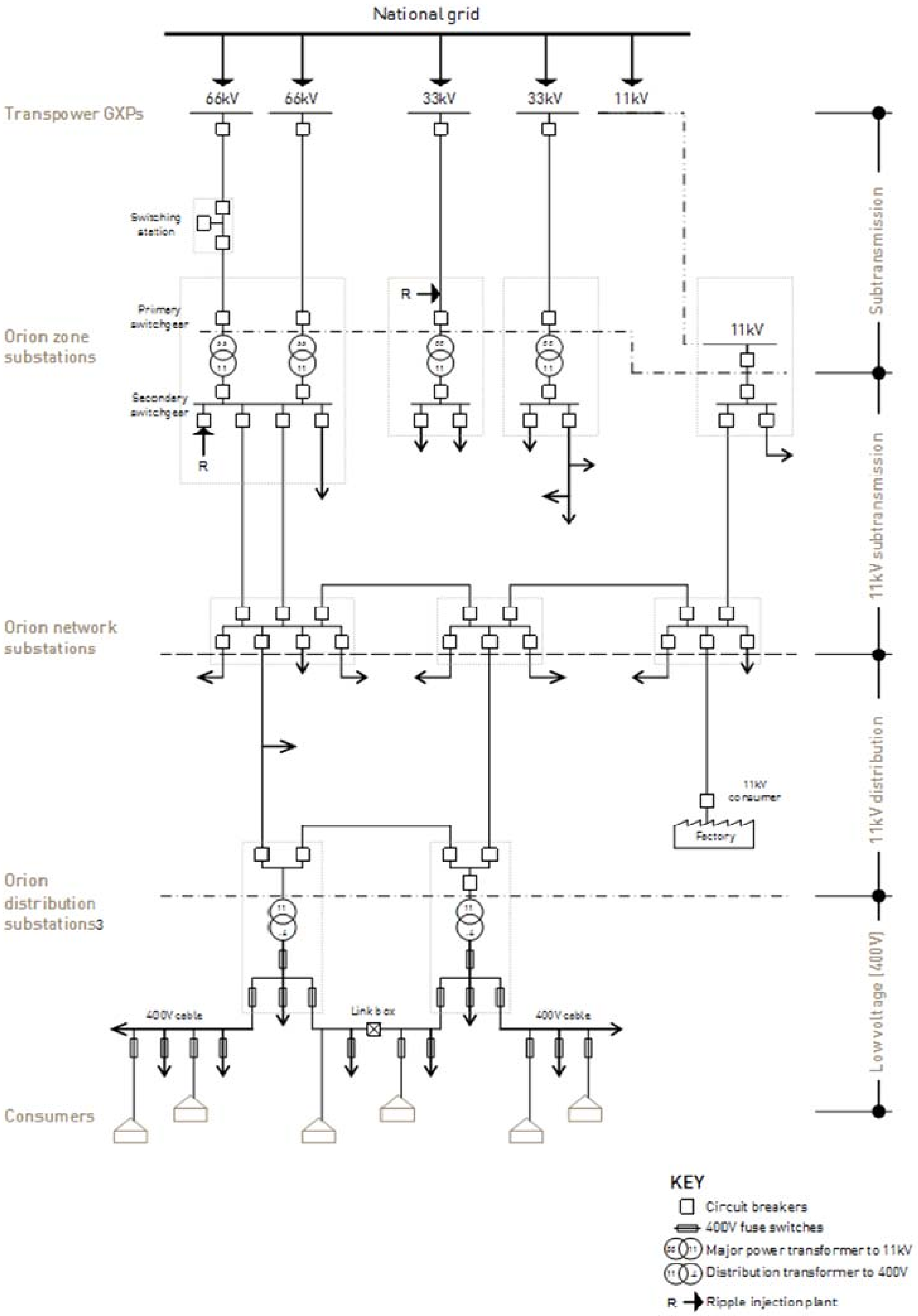
Zone substation	Peak load (MVA)	Firm capacity (MVA)	Voltage	Security standard class
Annat*	1.4	2.5	33kV	D3
Armagh	7.8	40	66kV	C1
Bankside*	8.5	10	33kV	D2
Barnett Park*	8.7	15	66kV	C4
Bishopdale/Papanui	28.8	34.3	11kV	C2
Brookside*	8.6	10	66kV	D2
Dallington	29.8	40	66kV	C2
Darfield*	6.4	7.5	33kV	D2
Diamond Harbour*	1.6	7.5	33kV	D3
Dunsandel*	8.5	10	66kV	D2
Duvauchelle	4.7	7.5	33kV	D2
Fendalton	35.0	40	66kV	C2
Foster	24.8	26.7	11kV	C2
Greendale*	7.4	10	66kV	D2
Grimseys-Winters	21.1	26.5	11kV	C2
Halswell	13.7	23	66kV	C4
Harewood	6.2	7.5	33kV	C4
Harris	10.1	17.4	11kV	C4
Hawthornden	30.4	40	66kV	C2
Heathcote	23.6	40	66kV	C2
Highfield*	6.4	7.5	33kV	D2
Hills*	5.5	7.5	33kV	D2
Hoon Hay	28.3	40	66kV	C2
Hornby	13.2	20	33kV	C4
Hororata*	7.0	7.5	33kV	D2
Ilam	7.6	11	11kV	C4
Killinchy*	7.7	10	66kV	D2
Kimberley	3.7	7.5	33kV	D1

Knox	12.2	12.3	11kV	C3
Lancaster	21.2	40	66kV	C1
Larcomb*	5.1	7.5	33kV	D3
Lincoln	7.6	10	33kV	D2
Little River*	0.7	2.5	33kV	D3
McFaddens	39.1	40	66kV	C2
Middleton	27.0	40	66kV	C2
Milton	34.5	40	66kV	C2
Moffett	15.4	18.1	33kV	C2
Montreal	7.7	12.7	11kV	C3
Motukarara	1.8	2.5	33kV	D3
Oxford Tuam	13.2	40	66kV	C1
Pages-Kearneys	10.3	17.2	11kV	C4
Portman	10.8	24	11kV	C4
Prebbleton	4.4	23	33kV	C4
Rawhiti	28.0	40	66kV	C2
Rolleston	11.4	10	33kV	D2
Shands	9.6	20	33kV	C4
Sockburn	23.5	35	33kV	C2
Spreydon	10.1	16	11kV	C4
Springston*	5.4	7.5	33kV	D2
Te Pirita*	8.9	10	66kV	D2
Teddington*	1.2	2.5	33kV	D3
Weedons	5.8	7.5	66kV	D2

* denotes single transformer at the site

Sub transmission security levels and rationale

Our high level distribution system architecture is shown in the following figure.



The majority of our urban zone substations supply a network of ‘primary’ 11kV cables connected to 239 network substations. These network substations in turn supply some 4,000 distribution substations on a secondary 11kV cable network.

Since our 2007 network architecture review, our preferred layout of 11kV feeders is a radial design which is gradually replacing the primary ring layout. The low voltage (400V) system to which most of our consumers are connected is supplied from these distribution substations.

The quantities of each of our major asset types which make up the distribution system are shown in the following table.

Distribution system asset quantities

Category	Description	FY12
Total network	Lines and cables (km)	14,904
	Zone substations	53
	Distribution substations	10,744
Overhead lines (km)	66kV	155
	33kV	303
	11kV	3,237
	400V	2,109
	Street lighting	940
	Total lines	6,744
Underground cables (km)	66kV	49
	33kV	33
	11kV	2,417
	400V	2,589
	Street lighting	1,996
	Communication	1,076
	Total cables	8,160
Zone substations	66kV	21
	33kV	22
	11kV	10
Distribution substations	Building (network)	239
	Building (distribution)	268
	Ground mounted	4,100

	Pole mounted	6,271
Embedded generation	Greater than1MW	10 consumer owned sites
Major business consumers	Loads between 0.3 MW and 5MW	320

Although we have relatively few generators on our network above the size of 1MW, there are a number of sites where the combined capacity sums to more than 1MW. Most of these generators are used for security of supply and peak load lopping and therefore only operate for approximately 100 hours per year.

The following table shows the ICPs on our network where total generation at that site exceeded 1MW as at 31 March 2012.

Large connections

ICP	Consumer
0005902207RNF3F	Christchurch Hospital St Asaph St Sub CB31
0005902541RN317	CCC Sewage Plant North.
0006678963RN383	Ravensdown
0007130868RN174	Christchurch International Airport CB111
0006830390RN9DD	Foodstuffs Hornby
0006804179RN09D	Lyttelton Port Co From U2 C152 22 to U 34
0005882699RN40B	CCC Waste Management Pumping Stn No 1
0007121449RN529	Pump 1 CCC Waste Water Station
0007121448RN96C	Pump 2 CCC Waste Water Station
0005872235RN697	College of Education Boiler and Kitchen
0005902460RNB03	Winstone Wallboards T1 Plasterboard
0005902223RN360	Hillmorton Hospital Linen Services
0005977525RN074	CCC Civic Offices CB 33
0006678955RN5F4	CWF Hamilton
0006804080RN7DF	Lyttelton Road Tunnel
0007112646RN33C	Windflow Technology Ltd
0007109818RN9A5	St Georges Hospital - Stage 2

0005902177RN961	St Georges Hospital
0007126217RNCDC	NZ Post Mail Sorting
0007131160RNBC9	11kV metering Feredays Island
0007131306RNFB1	Mobile Generator Truck 1 V755
0005882532RN1C3	C.C.C. Water Services Unit - Alport PS15
0007138178RNFD0	Mobile Generator Truck 3 V760
0006085148RNED4	CCC Water Services Unit - Lake Terrace
0007131305RN371	Mobile Generator Truck 2 V751
0006204023RN0A9	Burwood Hospital
0005882982RNF7D	C.C.C. Water Services Unit - Tyrone Street
0006160590RN3B2	Carlton Taylor Industries Ltd.
0006085237RN754	CCC Water Services Unit - St Johns
0007116365RN12C	CCC Water Services Unit - Worcester
0006673678RN715	Canterbury Clay Brick
0006085105RN32A	CCC Water Services Unit - Mays
0006440525RN851	C.C.C. Pump Denton Park
0007144198RN453	Landcare - Fleming & Godley Buildings
0006084990RN02F	CCC Water Services Unit - Avonhead
0006087329RN426	CCC Water Services Unit - Aldwins
0007112440RN8B4	CCC Water Services Unit - Riccarton
0006577202RN6EC	Airport Maintenance Yard
0007118915RN6BB	Thomas Cameron Wind Generator
0006578896RNB6B	Christchurch Women’s Prison

9.7.4 Distribution substations

Our urban distribution substations are housed in either a steel kiosk or an Orion or customer owned building.

For transformers up to 500kVA (typical for residential subdivisions) our ‘full’ kiosk completely encloses the transformer and 11kV and 400V switchgear. In industrial areas where a larger transformer is required (or maybe in the future) we install a ‘half’ kiosk arrangement which houses the 11kV and 400V switchgear with an outdoor pad for the transformer.

To improve operator and public safety the 11kV and 400V switchgear is transitioning from exposed live arrangement to touch safe, arc contained switchgear. We are evaluating the costs and benefits of real time monitoring and 11kV control at our distribution substations.

Although we have completed our urban 11kV architecture review project (see Appendix 7, NW70.60.06 Urban 11kV Network Architecture Review) we will undertake an LV architecture review in FY13 and FY14 before drawing final conclusions about the level of 11kV ‘SMARTS’ at distribution substation sites. We expect there will be 11kV synergy benefits from new technologies that meet our 400V architecture review conclusions.

Our rural network also includes pole mounted distribution substations up to 200kVA. In this case the switchgear arrangements are a simple 11kV ‘drop out’ fuse arrangement and pole mounted fuses for the 400V. Refer to NW70.53.01 for our approach to distribution substation design and our NW70.60.06 Urban 11kV Network Architecture Review.

9.7.5 Low voltage network

Our low voltage network design is described, at high level, in our Network Design and Overview standard (NW 70.50.05). This standard sets the ‘after diversity maximum demand’ criteria per lot and the level of security of supply required.

For our urban network, our LV design criteria require an interconnected LV network so that supply can be restored by switching for planned and unplanned outages on the LV network or distribution transformers. Connection/disconnection points are provided by boundary boxes although some older parts of our network contain t-joints with isolation in the customer meter-box.

All new urban subdivisions/connections are underground but overhead LV is used on the rural network where appropriate. It can be seen from the following table that approximately 55% of our LV network is underground.

LV network length

Asset description	FY12
400V overhead lines	2,109km
400V underground cable	2,589km

9.7.6 Secondary systems

Communications

Reliable and effective communication systems are an essential component of our network as it is an integral part of the remote indication and control of network equipment, and provides contact with operating staff and contractors in the field.

We have both data and voice communication systems.

- our voice communication system uses very high frequency (VHF) radio links as well as private and public telephone, cellular and paging networks. Our data communication system uses various technologies running over UHF radio, copper communication cables and fibre and is used for SCADA RTU links to provide access to substation engineering data
- our cable communication system is mainly in the Christchurch urban area, and is used to link the SCADA master station with the RTUs and for unit protection at our urban zone and network substations
- our portable data centre has been established to house our backup/mirrored servers. It is located away from our main operating site and provides further resilience in our communications network.

More information is provided in our asset management report NW70.00.34.

Load management systems

Our main network load management system (ripple injection) is used to control loads on the network by deferring energy consumption and peak load, and therefore network investment. Its other main function is tariff switching. It works by injecting a signal into our network that is acted upon by relays installed at the consumer’s connection point.

The ripple relays are owned by the retailers, with the exception of some 2,000 used for streetlight control.

Our load management system is comprised of a master station and two ripple injection systems:

- load management master station - the load management master station is a SCADA system that runs independent of the network operational SCADA system. The master station consists of two redundant database servers and two communication line servers (CLS) on dedicated hardware. The load management software utilises algorithms specifically developed for Orion. Loading information for the system is derived from RTUs located at the GXPs and zone substations. Sources of information and communication paths are duplicated where reasonably feasible
- ripple injection system - Telenerg 175 Hz - this system operates within the urban 66kV subtransmission network and is the major ripple injecting system controlling the load of approximately 150,000 consumers. It is made up of more than 20 small injection plants connected via circuit breakers to the 11kV network at individual 66/11kV zone substations and Christchurch urban 33/11kV zone substations
- ripple injection system - Zellweger decabit - the Decabit system operates within the 33kV subtransmission network and is made up of five plants connected to the 33kV system, via air break isolators and protected by circuit breakers, at Springston (two

plants), Moffett, Hornby and Hororata zone substations. Backup for the injection plants themselves is provided by pairs of plants in each GXP supply area.

More information is provided in our asset management report NW70.00.37.

Distribution management systems (DMS)

A DMS is a collection of applications designed to monitor and control the entire distribution network efficiently and reliably. It acts as a decision support system to assist the system control operators and field operating personnel with monitoring and control of the electricity distribution system. Improving the reliability and quality of service in terms of reducing and minimising outage time, and maintaining acceptable frequency and voltage levels are the key deliverables of a DMS.

We have had different forms of supervisory control and data acquisition systems (SCADA) on the network since the early 1970s. These systems have traditionally been based on a master station (central control centre) communicating with the remote terminal units (RTU) at remote sites throughout the network thus providing real time information from a small portion of the network – generally zone substations.

A DMS takes basic SCADA to the next level – by integrating SCADA real time information from the field with a comprehensive network operating model with full connectivity, including customer connections and operated in near real time.

By combining tele-metered information from the SCADA system and field operator switching actions with the locations of outage calls from customers, a rule engine is used to predict the locations of outages. Based on this information the DMS can assist the system control operators to restore power by helping automate the isolation and restoration procedures. Our DMS is comprised of the following assets:

- at the heart of the DMS is a comprehensive network model (including all lines, cables switches and control devices, etc.) with full connectivity operated in near real time. This system is used to manage switching processes on the network. It facilitates the management of work planning, safety associated with switching and associated documentation. It also maintains switching logs
- a comprehensive SCADA master station is tightly integrated into the DMS and provides tele-metered real-time data to the network connectivity model
- outage management system (OMS) allows for the identification, management, restoration and recording of faults. In the case of a fault or event, the OMS assists in determining areas affected by outages utilising predictive algorithms. This allows us to give our customers better information regarding what has occurred and when we expect to be able to respond
- mobile despatch - mobile network operators are equipped with personal digital assistant (PDA) devices connected to the cellular network. Switching instructions are sent directly to the PDAs from the DMS for execution by the operator. As they carry out the switching they confirm the steps are completed and the network model is updated with the changes in close to real time
- historian – collects, stores and provides analysis tools for time series data – binary and analogue. The basic DMS system is equipped with only rudimentary time series storage capabilities and thus a separate historian is required. The time series data stored in the historian is used by various applications throughout the

organisation for planning, network equipment condition analysis and display of network operating performance such as reliability
- real-time load flow analysis - because the DMS has access to large amounts of real time field data and maintains a real time connectivity model, it is possible to carry out a near real time load flow calculation on the network model. The load flow can be used to predict network operating conditions at locations where no tele-metered data is currently available (state estimation) and can also be used to carry out ‘what if’ calculations to predict the effects of modified network topologies/switching
- information interfaces to consumers - the DMS contains a large amount of information about the state of the distribution system. Applications can be written which extract this data from the DMS and historian and present its reports or data on web pages.

More information is provided in our asset management report NW70.00.36.

Metering

Our core metering equipment comprises:

- high voltage (11kV) consumer metering - we own current transformers (CTs) and voltage transformers (VTs) used for metering, along with associated test blocks and wiring, at approximately 75 consumer sites. Retailers connect their meters to our test blocks. All Orion CTs and VTs are certified as required by the Electricity Governance Rules
- Transpower GXP metering - we adopted GXP based pricing in 1999, and most of our revenue is now derived from measurements by Transpower's GXP metering. Orion also owns metering at 10 Transpower GXPs. We input the data from these meters into our SCADA system. Our measurements can also help the Reconciliation Manager to estimate data if Transpower’s meters fail, or are out of service. Transpower has dedicated meters at all metering points. The GXPs at Arthur’s Pass and Castle Hill share CTs with our metering. This is also the case for two supply transformers at Papanui GXP. All VTs are shared between Orion and Transpower. Although a truly credible check metering system would have stand-alone components with their own traceable accuracy standards, this is impractical
- power quality measurement metering - our power quality management in the past has been mainly reactive. We have responded to consumer complaints. We have not known the general underlying power quality performance of the network and whether it is deteriorating over time as an increasing number of non linear loads are connected to the network.

More information is provided in our asset management report NW70.00.38.

Generators

We have a number of medium to large diesel generators. Ten 550kVA generators can be strategically placed throughout our urban network. They are used for emergency backup and can be switched on-line in a short time frame if there is a loss of supply. Three of them have synchronisation gear fitted. We have three truck-mounted units of 375, 400 and 440kVA (mobile) and one 110kVA trailer mounted generator, which are used to restore supply at a distribution level during a fault or planned work. The truck-mounted units are all fitted with synchronisation gear. We have a further 550kVA unit attached to our main office building with synchronisation gear and a 30kVA without synchronisation gear. We have recently purchased two 2500kVA 11kV generators with synchronisation gear.

More information is provided in our asset management report NW70.00.39.

9.7.7 Existing network assets

The lifecycle management of our existing assets is described in our Asset Management Reports for each asset category listed below. These contain information on age profiles, condition, historic failure rates and systematic issues leading to replacement decisions.

Asset management reports

Asset type	Report reference
Circuit breakers - HV	NW70.00.33
Communication systems	NW70.00.34
Distribution management systems	NW70.00.36
Generators	NW70.00.39
Load management systems	NW70.00.37
Metering	NW70.00.38
Overhead lines - 11kV	NW70.00.27
Overhead lines - LV	NW70.00.25
Overhead fines - subtransmission	NW70.00.26
Property - corporate	NW70.00.42
Property - network	NW70.00.43
Protection systems	NW70.00.22
Substations	NW70.00.44
Switchgear - HV and LV	NW70.00.24
Transformers - distribution	NW70.00.40
Transformers - power	NW70.00.23
Underground cables - 11kV	NW70.00.30
Underground cables - 33kV	NW70.00.31
Underground cables - 66kV	NW70.00.32
Underground cables - communication	NW70.00.28
Underground cables and hardware - 400V	NW70.00.29
Voltage regulators	NW70.00.41

9.7.8 Asset values

The following table provides our summary of the regulatory asset values of our network and non network assets as at 31 March 2012. A more comprehensive schedule, by asset type, is shown in Appendix 26.

Closing FY12 RAB values by asset category

Asset categories	($ millions)
Subtransmission network	138.6
Distribution network	330.5
Switchgear	101.5
Low voltage distribution network	229.0
Supporting or secondary systems	17.1
Non system fixed assets	26.6
Total	**843.4**

9.8 Demand, connection and generation forecasts

9.8.1 Forecasting demand

Introduction

Developing our network to meet future demand growth requires significant capital expenditure. Before spending capital on our network, we consider a number of options including those available in demand side management and distributed generation.

The amount we spend on our network is influenced by existing and forecast consumer demand for electricity and the number of new consumer connections to our network.

The growth rate in overall maximum network system demand (measured in megawatts) traditionally drives our capital investment. Maximum demand is strongly influenced in the short-term by climatic variations (specifically the severity of our winter conditions). For FY12, the peak total injection was 633MW which was supplied through Transpower GXPs supplemented by export from embedded generators of 1.6MW. The maximum export recorded from embedded generators was 7.7MW on the evening of 1 July 2011.

During the winter of 2011, prior to the two snow storms experienced that winter, the peak half hour for the winter had been only 533MW (based on load through Transpower GXPs i.e. excluding embedded generation). The July 2011 snow storm led to a higher half hour peak of 572MW (7%). The August 2011 snow storm emphasised the impact of variations in climate conditions when the load peaked 10% higher again at 633MW.

In the medium-term, changes in maximum system demand are influenced by growth factors such as underlying population trends, growth in the commercial and industrial sector and changes in rural land use.

Environment Canterbury's Clean Air Plan (CAP) has placed some pressure on load/demand growth as the plan bans open fires and inefficient log burners, and encourages consumers to install electric heat pumps. This impact is largely offset by more efficient heat pumps replacing some less efficient forms of electric heating, and increasing installation of insulation.

Another factor that has influenced our network development plans is in-fill housing in existing central suburbs and new housing estates in areas such as Belfast, Halswell, Wigram and to a lesser extent in Burwood, Cashmere, Huntsbury Hill, Redcliffs and Sumner – it is likely we will extend our urban 11kV network to meet these developments.

The earthquakes have added a new level of uncertainty to our demand forecasting. New information is continually emerging and we must respond to this and review our plans accordingly. The information presented in this CPP proposal is based on the most recent information we have available to us as at September 2012. We address the earthquake impacts explicitly in the following sections.

Energy and demand growth

To effectively plan the future of our network, we need to estimate the size and location of future loads.

Long-term growth in energy consumption had shown a consistent trend until the major earthquakes of 2011. This trend provides a first estimate of load growth both for the full network, and for specific areas within the network. However, any load forecasting is an approximation - load cannot be forecast with 100% accuracy. There is currently increased uncertainty due to:

- the drop in peak demand and energy consumption from population decreases (particularly in the east)
- reduced commercial load in central Christchurch (some of which is still cordoned off)
- increased electricity use for space heating in homes with damaged insulation
- increased electricity use due to the removal of solid fuel burners in damaged houses.

Energy and demand growth is a function of many inputs. Network development is driven by growth in peak demand (not energy); therefore we focus on demand growth rather than energy. In general, two factors affect load growth:

- population increases
- changes in population behaviour.

At a national level, it is reasonably easy to forecast population growth. When the national forecast is broken down to regional level, the accuracy is less reliable but remains useful in predicting future demand growth. Other variables which influence consumer behaviour are also relevant. These include technological advancements, energy options available and legislated requirements such as Environment Canterbury's CAP. It is difficult to forecast these variables accurately. In addition our DSM strategies shape our peak demand load forecast.

As a high level of accuracy is required to build an appropriate electricity distribution network, we treat load forecasts as a guide. A major 66kV or 33kV network development project takes approximately three years to plan, design and build, while smaller 11kV projects take around 18 months. A 400V solution can take several months. It is therefore prudent to apply flexibility in how we implement our network development proposals, rather than rigidly adhere to a project schedule based on an historical forecast.

We derive our load forecast from a combination of bottom up inputs (for example household growth forecasts from CCC) and historical trends in growth. We adjust it to reflect other relevant factors such as Environment Canterbury's CAP and our DSM initiatives. We have also amended our historical approach in order to consider the impacts of the earthquakes.

9.8.2 Key demand forecasting assumptions

Impact of February 2011 earthquake

The February 2011 earthquake reduced energy delivery volumes by approximately 10%. Recent energy consumption suggests that energy volumes are starting to increase again but it is too early to draw any conclusions. Projecting ongoing recovery post-earthquake is difficult.

For post earthquake population projections we are using census area unit projections provided by the Greater Christchurch Urban Development Strategy (UDS). UDS has provided eight different scenarios which include:

- four high level scenarios (Rapid/Quick/Moderate or Slow recovery)
- two locational variations - "Business as Usual" and "CBD".

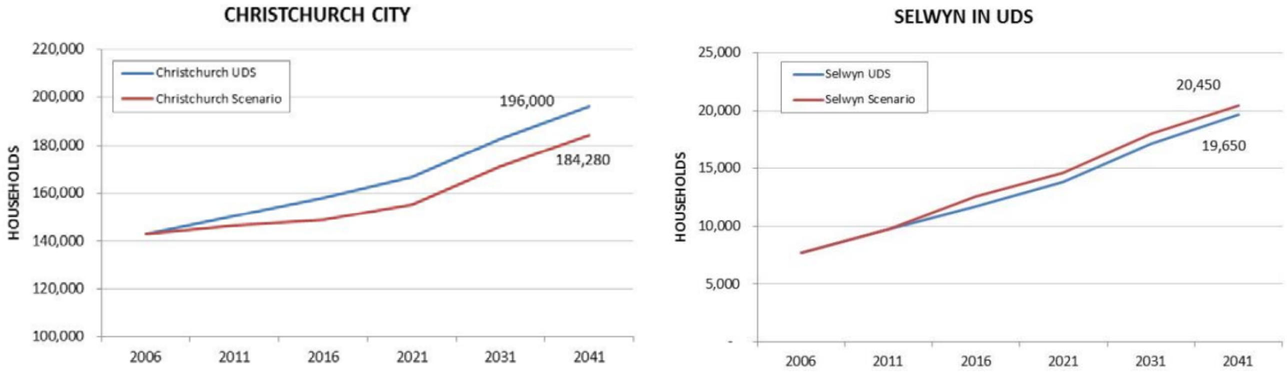
Details of these forecasts are provided in our load forecasting policy document (NW70.60.12).

The four recovery scenarios were developed at a workshop on November 17, 2011, involving the UDS partners, CERA and NZTA. The "CBD" variation assumes greater aspirational CBD residential development with corresponding lower growth for the rest of Christchurch. It is based on greater growth within the Four Avenues from 2021 onwards. This assumes that the redevelopment of the Central City is successful and encourages a higher level of residential development than was anticipated in pre-earthquake projections.

The scenario recommended by CCC (while acknowledging all are plausible) is the "Quick Recovery" with "Business as Usual". We have followed this recommendation.

The Quick Recovery Scenario projects a 7% reduction in city households at 2021 compared with pre-earthquake projections. This reflects an initial population loss, slow growth until 2016, followed by stronger recovery in the 2016 - 2021 period (although this is less than the pre-earthquake outlook), and a return to the Medium-High growth annual trend after 2021. CCC plan to rework their models later this year so we can expect an update in the first half of 2013 which is likely to provide refined population projections for our 2014 AMP. For Selwyn District, the "Quick Recovery" scenario projects a 4% increase in households at 2021 compared with pre earthquake projections. This scenario has no initial population loss for Selwyn District, higher growth until 2016 compared with the pre-earthquake outlook, followed by a return to the Medium-High growth annual trend thereafter. These are illustrated in the following charts.

Quick Recovery Scenario compared with pre-quake projections



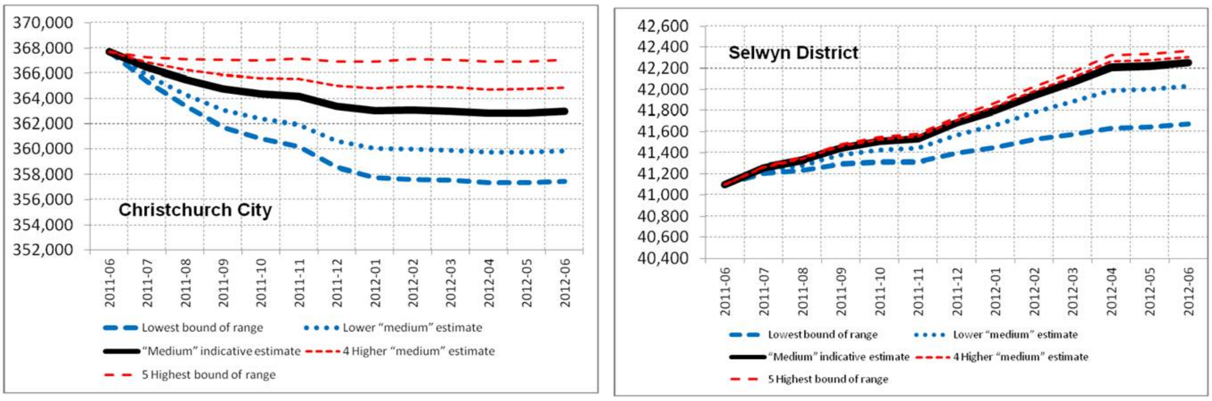
Post earthquake population changes

The UDS August 2012 report estimates that the city's loss of permanent residents has bottomed out (mid estimate 5000). This excludes temporary work force arriving for rebuild. The report notes:

- a top down approach has been applied
- NZ Post redirections data suggests that net population loss during the June 2012 year due to net long term internal departures from Greater Christchurch (ie most of Selwyn, Waimakariri and CCC) was concentrated in the July 2011 to February 2012 period
- the March 2012 quarter may have seen some return migration of children and their parents who had relocated on a short term basis in response to the major disruption to schools and services in the June 2011 quarter.

The following charts show the UDS estimates of population change as at June 2012.

Council population estimates



Temporary workforce

There is additional uncertainty regarding the temporary workforce population who are helping with the Christchurch rebuild.

In April 2012, best estimates were 24,000 construction-related workers (plus 12,000 support staff) during peak demand in the third quarter of 2013. In September 2012 CERA estimated 15,000 to 17,000 temporary construction workers are expected by the end of 2014, plus 15,000 other workers in support industries and due to business growth. They estimate approximately 10,000 temporary workers are already here (as at September 2012), which almost recovers from the permanent resident population loss of 10,600 according to Statistics NZ data. This suggests that so far about one third of the expected 30,000 temporary workers have arrived.

CERA are working on an accommodation model (as this is constraining growth), an economic model and a workforce model (the latter two are at territorial level, not census area unit level at this stage). They are expecting to have an update around Spring 2013 along with a forecast of the impact of $30 billion expected to be spent on the Christchurch rebuild.

Population forecasts

The October 2012 Statistics NZ data (which excludes the temporary workforce) shows that the UDS scenario data, used in our forecasts, is just over the Statistics NZ High Projection for 2016, and just under their High Projection for 2021. This correlates well with the expectation that many of the 30,000 temporary workforce will still be here in 2016, but will have left by 2021. This is illustrated in the following table.

Forecast population for TLA areas – Christchurch city (000)

Projection at 30 June	2006	2011	2016	2021	2026
Stats NZ - High		372	**390**	**414**	438
Stats NZ - Medium	362	368	376	389	402

Stats NZ - Low	364	361	364	366
UDS Quick BAU Recovery Scenario (March 2012) - excludes temporary workforce		**393**	**406**	425

Impact of economic downturn

Peak demand on our network is influenced mainly by the harshness of the winter weather, rather than economic activity. Peak demand had not exceeded the high peak reached during our 2006 winter snow storm by the time of the February 2011 earthquake. The potential impact of the recent economic downturn has not been specifically factored into this demand forecast as our underlying growth forecasts are linked (via the UDS) to Statistics New Zealand population projections.

Impact of DSM on our load forecasts

Our DSM strategies, discussed in Section 9.13.9, impact on our peak load forecast. Our network peak demand forecast assumes that 2MW of DG will be added to our network each year. This is commensurate with growth in DG over the last five years. Because it is difficult to predict the location of new DG, we have not attempted to apply the growth in DG to the zone substation load forecasts. Instead we encourage DG in constrained areas on our network by publishing the area specific network deferral value of DSM initiatives.

The impact of other DSM initiatives such as price signalling, night rate tariffs and hot water cylinder control is captured in the underlying inputs to our load forecast. For example, we monitor the after diversity maximum demand (ADMD) of new households and apply this figure to the projected number of subdivision lots for an area to determine a forecast which includes the impact of our DSM initiatives.

At the 11kV feeder level, and despite the increased size of households and the increased uptake of electrical appliances and heat-pumps, the ADMD has only grown by 0.5kW to around 3.5kW per household. This process is applied to our subtransmission forecasts for both new subdivisions and urban infill (3kW per infill household).

A similar process is also applied on a per hectare basis for industrial subdivisions but we recognise that specific consumer requirements can cause a significant variance from the average case.

9.8.3 Method and assumptions for determining GXP and zone substation forecasts

Our network feeds both high density Christchurch city loads and diverse rural loads on the Canterbury plains and Banks Peninsula.

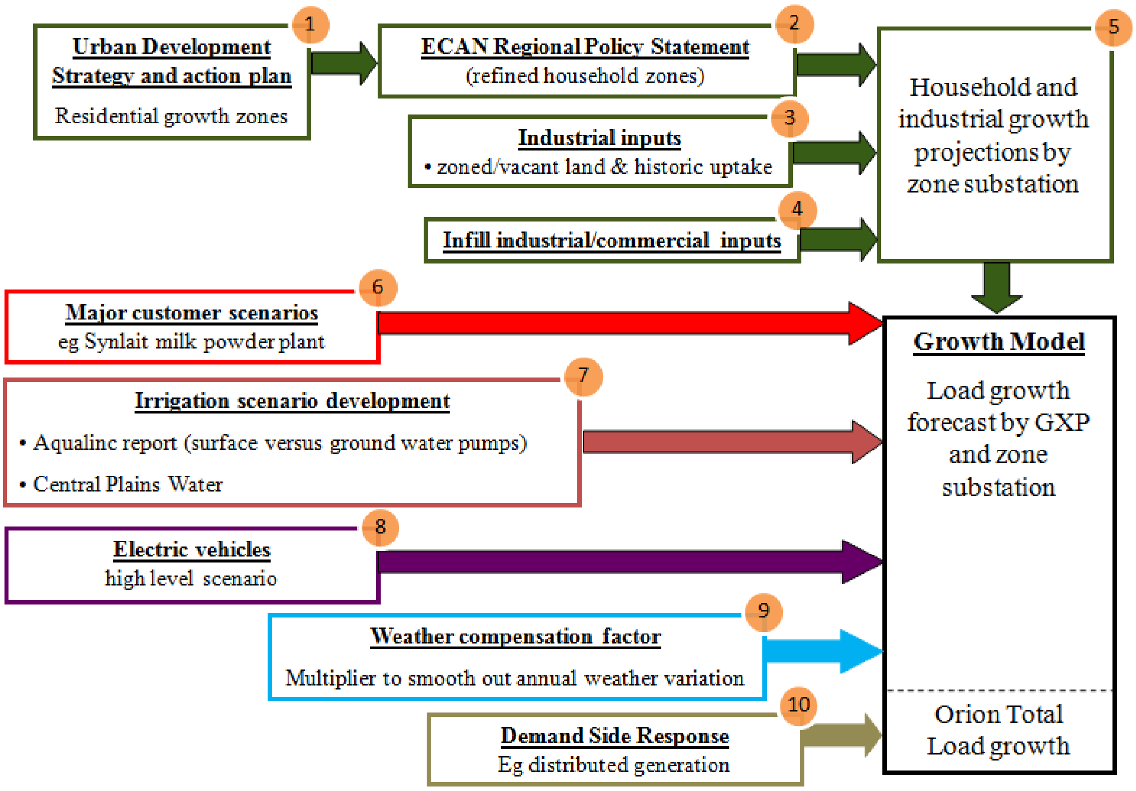
Growth in electricity consumption can occur from an increase in population and also the introduction of new end-use applications. Growth in electricity consumption in the city and on Banks Peninsula has historically matched growth in population (holiday population for Banks Peninsula). Conversely, electricity growth on the Canterbury plains has not matched population growth but has been driven by changes in land use and hence changes in electricity use.

Winter peak demand on our network is mainly driven by growth in the city and is anticipated to increase by approximately 53MW (9%) over the next 6 years, ie: to winter 2018, the last peak within the CPP regulatory period. Our rural network peaks in the summer and it is anticipated to increase by approximately 41MW (41%) over the next seven years, ie: to the end of the CPP regulatory period.

Our major network capex projects included in this CPP proposal seek to ensure that capacity and security of supply can be maintained for the growth rates described above.

Key steps in forecasting methodology

The following section describes the factors and methodologies used to estimate the quantity and location of load growth on our network. Further supporting information is provided in our forecasting methodology policy document NW70.60.12. The following diagram illustrates the key steps in this process.



We forecast growth at the zone substation level and translate this up to Transpower's GXPs and finally to our total network demand forecast. This total network forecast is compared with a linear projection forecast.

Territorial local authority planning

Our network spans two territorial authority areas; Christchurch city and Selwyn district. Both territorial authorities publish useful area planning information and we use this extensively to plan for growth on our distribution network.

In addition to individual territorial plans, the UDS provides a long term strategy for growth in the greater Christchurch region. The UDS proposes a greater level of infill development in central Christchurch and encourages growth at Rolleston and Lincoln townships. Because consolidated areas of growth are less costly to service than sparse development, it is expected that the UDS outcome will lead to lower than otherwise costs for our consumers. The UDS forecasts the growth in household numbers by defined areas. Further explanation of this data and also our industrial sector forecasts are described in the following sections.

Christchurch city

The CCC publishes reports on vacant land on an annual basis.

With the advent of the UDS, the CCC has also forecast yearly household growth by census area unit, to 2041. To forecast the growth in residential demand in the CCC area, we map each of the area units to one or more zone substations. CCC has provided a post earthquake update which includes household forecast scenarios as described above.

To forecast industrial growth we use the CCC industrial vacant land reports to identify areas developed and zoned for potential growth. We utilise historical uptake rates and market judgement to allocate 20 to 25 Ha of growth per annum to the different areas of available land. These allocations are mapped to a zone substation with a forecast load density of 130kW per hectare. Finally, we use the CCC land zone maps to determine the areas suitable for commercial and industrial infill growth. This part of our forecast is a relatively subjective process and is heavily dependent on the commercial development market.

In summary, and recognising the earthquakes have largely destroyed the CBD, the UDS forecasts, in the medium term, that there will be an increase in residential infill within the central and inner city areas around the shopping malls. In the short term, major subdivision growth is planned for Wigram, Halswell, Belfast and Marshlands. Industrial development is expected to mainly continue in Hornby and Islington in the short term and in Belfast in the medium term.

The Canterbury earthquakes and subsequent development of red zones will to some extent accelerate growth in some areas and may create pressure to release additional land outside the UDS for development. An example of this is near the airport along State Highway 1. The CCC is carrying out a North West Area Review looking at rezoning 100 hectares, currently zoned rural, for industrial business purposes to accommodate demand for business land in the north west of Christchurch.

Selwyn district

Most of our zone substations within the Selwyn district are required to meet irrigation load and are predominately summer peaking. However, significant residential growth has occurred around Rolleston and Lincoln zone substations. These are winter peaking substations and, similar to CCC, we use the UDS/Selwyn household growth projections to forecast residential growth in the greater Selwyn region.

The Izone industrial park in Rolleston has also experienced significant growth in recent times and we are working closely with Izone to ensure that our forecasts in this area are consistent with their expectations. Post earthquake household forecasts were not available at the time of writing. Although the Rolleston household growth rate is anticipated to accelerate, it is expected to be dominated by significant proposed new industrial load in Izone.

9.8.4 Observed and extrapolated load growth

Energy throughput (GWh)

Network energy throughput for FY12 was 3,070 GWh (including export from embedded generation of about 3.4GWh), down 3.6% on the previous year.

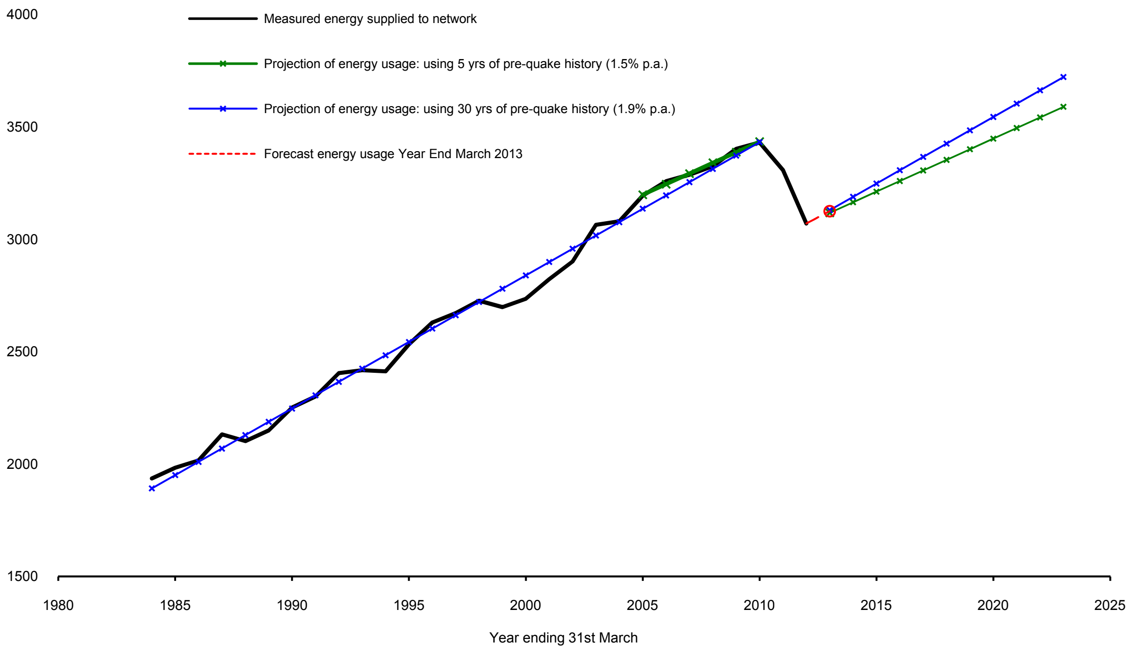
Our 30 year history suggests an average steady growth rate of about 1.9% each year. The five years prior to the earthquakes were lower than the long term average at 1.5% per annum.

Environment Canterbury's CAP has had only a modest impact on energy use, as surveys suggest that the high conversion rates of solid fuel burners to heat pumps has been balanced in part by consumers switching from resistive heating to higher efficiency heat pumps.

A severe economic downturn (partly due to the GFC) and closure of several major consumers had led to a slowing in energy growth prior to the earthquakes.

We have observed a step change downwards in energy demand as a result of the 22 February 2011 earthquake. While there has been some recovery, ongoing demolition work in the CBD and planned demolition in the east is significantly affecting volumes in those areas. Longer term, we expect that new business and residential buildings will be more energy efficient than the older buildings they replace, and the CERA Central City recovery plan also implies fewer, much smaller rebuilds. Energy volumes have started trending up again since February 2012 but the medium term view is very uncertain. The following graph shows our forecasts of short and long term pre-earthquake energy demand growth:

Orion network annual energy trends - Energy (GWh p.a.)



Maximum demand

Maximum demand is the major driver of investment in our network. This measure is very volatile and normally varies by up to 10% in any one year depending on the severity of winter weather.

The July 2011 snowstorm increased our network peak by 7%. After the August 2011 snowstorm the peak increased by a further 10%. Since our network demand peaks occur during winter, we can record the peak for FY13.

Our network maximum half hour demand, based on load through the Transpower GXPs, for FY13 was 577MW (the peak that occurred on 12 June 2012), down 55MW from the previous year. Forecasting peak demand at the moment has challenges (in addition to the earthquakes) including uncertainties with the global economy and unprecedented applications for embedded generation.

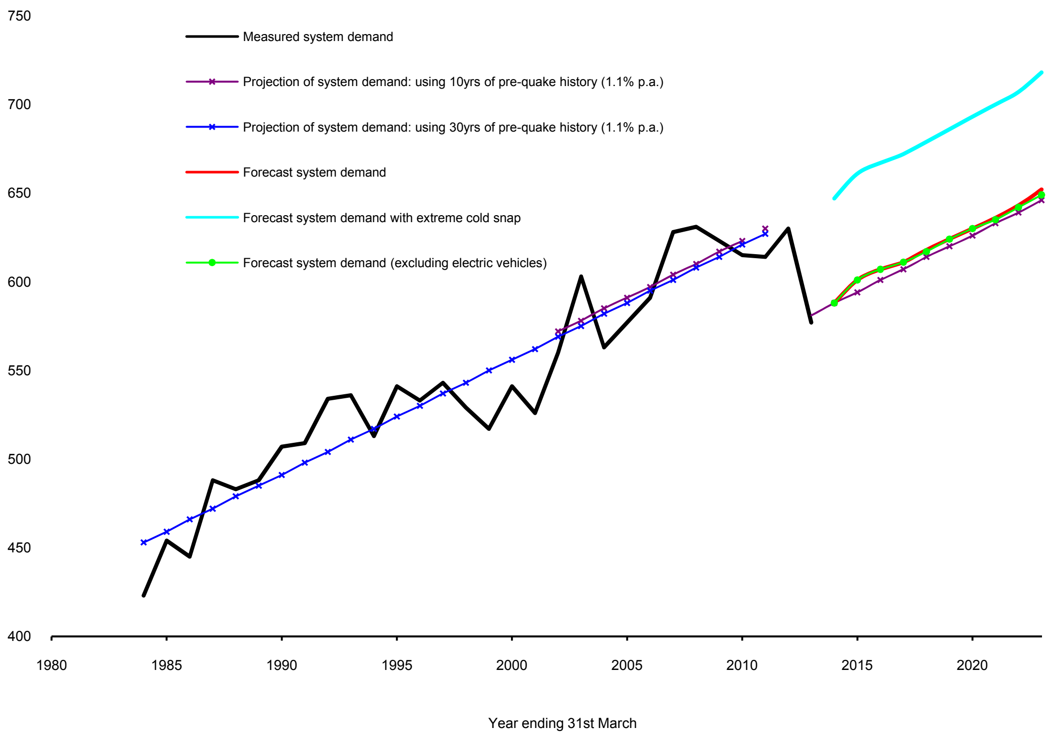
Excluding earthquake effects, the long and short term trends suggest future average maximum network demand growth rate of around 1.1% per annum. The graph of historical network demand shown below also includes three forecasts:

- Forecast demand (with and without electric vehicles) - these forecasts are based on underlying residential growth and industrial uptake models. We have also added an electric vehicle scenario to our forecast demand which assumes that 10% of households will have an electric vehicle by 2023 and 20% of these vehicles will be charged at peak. Network reinforcement expenditure is designed to ensure that nominal and security of supply capacity is provided for in this peak demand forecast. The above average increase in the next few years is due to major industrial growth which is dominated by new or expanding milk processing plants.

- Potential cold-snap peak - this forecast is based on snowstorm events similar to those in August 2011 when a record snowstorm changed short-term consumer behaviour. We experienced a loss of diversity between consumer types. Despite having no CBD and fewer consumers in the eastern suburbs, we experienced very high loads on Wednesday 17 August 2011. This followed a snow storm on the 15th. On Wednesday some schools and businesses reopened after being closed for two days while others remained closed for a third day. Our hot water service targets were stretched on 17 August 2011 and therefore ~25MW of hot water heating remained during our evening peak (~30% of load that could have been shed) were it not for our service target.

When planning our network, it is not economic to install infrastructure to maintain full security of supply during a network peak that may occur for 2-3 hours once every 10 years. Our forecasts are therefore used to determine the normal capacity requirements of our network.

Overall maximum demand trends on the Orion network – Demand (MW)



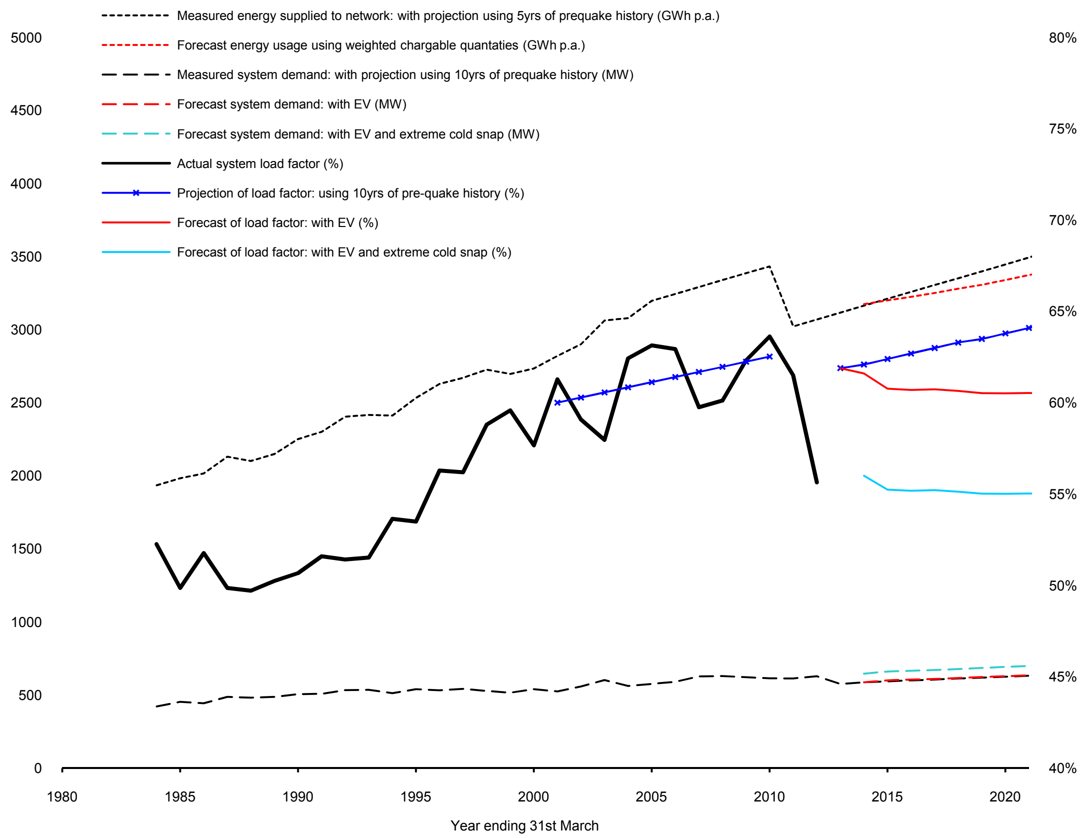
Overall system utilisation

Overall network utilisation is indicated by our system annual load factor (defined as the ratio of average to peak demand). Our annual system load factor has generally improved over the last few years, but can vary significantly as vagaries in our weather from year-to-year influence maximum demands. For FY12 our load factor was 56%, down 6% on the previous year. This was due to a combination of reduced energy consumption due to loss of connections after February 2011 earthquake and extraordinary peak demand following the August 2011 snow.

Improvements (increases) in load factor come from increased off-peak loads (irrigation and summer air conditioning), combined with effective control of winter peak loads through price signalling and encouraging other fuel use for on-peak heating. Winters with extreme cold weather often lead to lower load factors due to the very high peak load.

The present trends of reduced irrigation load growth, and increased electrical winter heating load suggest that our load factor may plateau around 60% to 65%.

System load factor - demand and energy (MW and GWh) per annum and load factor (%)



Load duration

With constantly changing load on our network, our peak demands that determine our network capacity generally only occur for very short periods in the year.

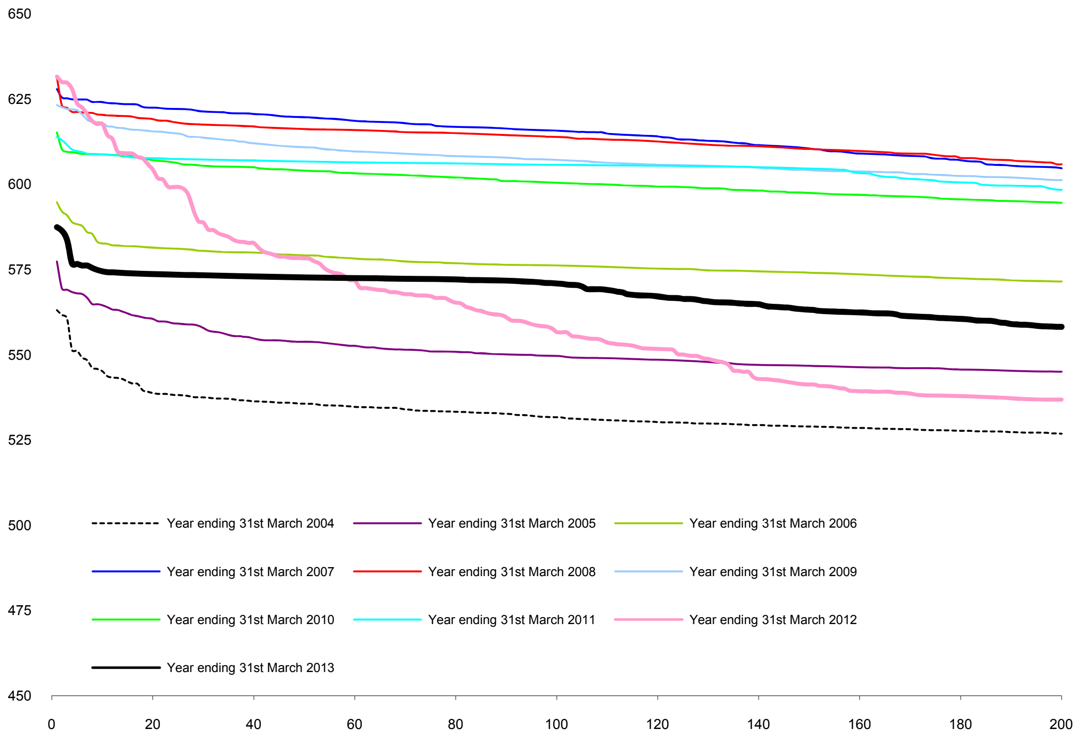
The following graph shows the load duration curves of our 200 peak half hour demands on the Transpower network over 10 years. The graph shows that demand side management has been successful in flattening the curve in recent years. The FY12 year is unusual in that consumer demand was reduced due to the earthquakes, but then new peaks were created with the July 2011 snowstorm, followed by extraordinary load due to the August 2011 snowstorm. In the six years prior, an increase in demand side management for 10 hours each year would have reduced our network peak demand by around 10MW. During winter 2012 just 1.5 hrs of DSM (on the afternoon of 6 June snow) would have been sufficient to reduce the winter peak by 10 MW. It is difficult to pick the time to utilise DSM to target these few hours when the curve is so flat. To reduce the peak by a further 10MW would require over 130 hours of DSM in these years. However, extreme weather conditions (as mentioned below) provide ongoing incentives for DSM.

The Transpower grid requires sufficient capacity to meet load during extreme weather conditions (such as the 2011 snowstorm) that may last for only a few hours. Peaking generation can help to delay the need for increases in Transpower's network capacity. This generation may need to operate for only a few hours over the largest peak demand times, as required to avoid Transpower's network constraints. In the 2011 winter, peaking generation of 30MW would only have needed to operate for about twenty hours to reduce our urban network maximum demand by about 30MW. In unusually prolonged cold conditions longer hours of operation might be needed.

Generation may also be used to reduce Transpower's charges. If used for this purpose, longer hours of operation might be needed, especially to avoid reductions in water heating service levels.

Control of the dominant winter maximum demands depends heavily on suitable price signals, and consumers' response to them. If this is to continue to be effective then it is important that electricity retailers continue to support demand side management initiatives. Of particular importance is the promotion of night rate tariffs and load control via the ongoing installation and maintenance of ripple receivers.

Christchurch urban area network – load duration curves – Demand from Transpower (MW)



Rural load growth

In contrast to our urban area, growth rates for our summer peaking rural areas have been high over the last 10 years.

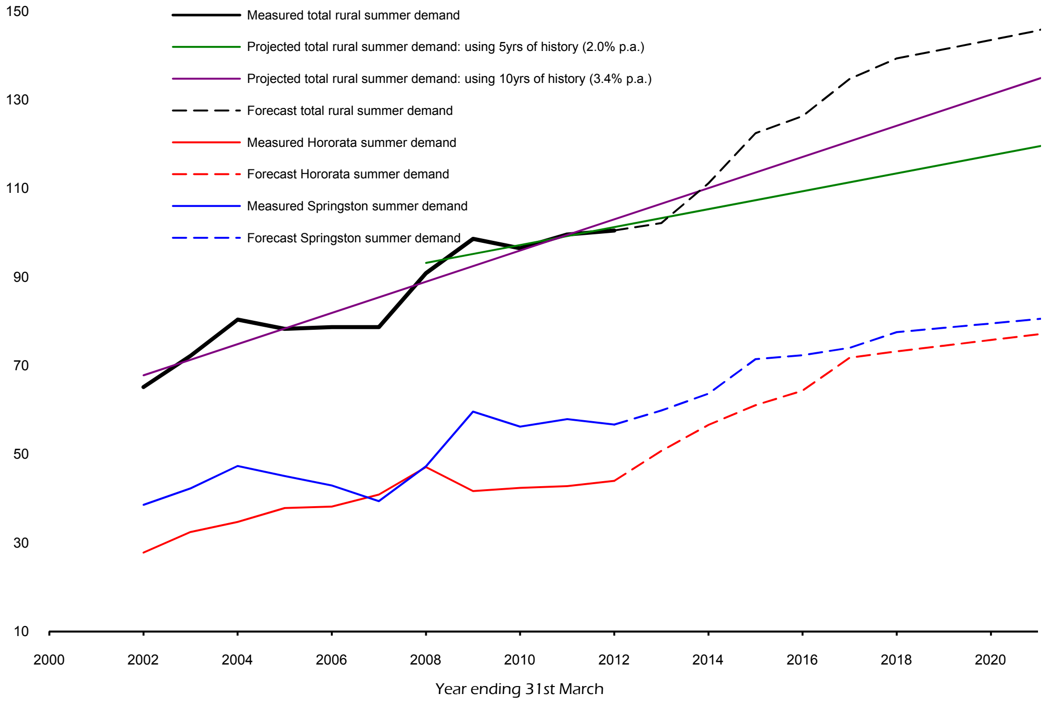
Since FY02, consumer applications to connect new load to our rural network have been reasonably consistent. However, the yearly variations in weather and in particular low summer rainfall resulted in an increase of 12MW and 7MW respectively across Hororata and Springston GXPs during the summers of FY08 and FY04. This demonstrates how variable peak loads can be, and how weather dependent they are – a dry summer in the Canterbury Plains causes an increase in peak demand as irrigation is required simultaneously across a large area.

Recently some irrigators with large ground-water irrigation schemes have installed surface river-take schemes in parallel with their existing schemes. These surface water schemes require a much smaller electric pump than the equivalent ground-water schemes, but are highly dependent on river flows and rain in the river catchment areas.

Irrigation load growth is expected to slow in the medium term as restrictions on the availability of ground-water take effect and more farms convert from ground-water to surface-water pumps. A 2010 Aqualinc study indicates the net result for most of our substations is no further growth due to irrigation loads. The exceptions are Dunsandel with a 7MW increase and Killinchy with 1MW increase.

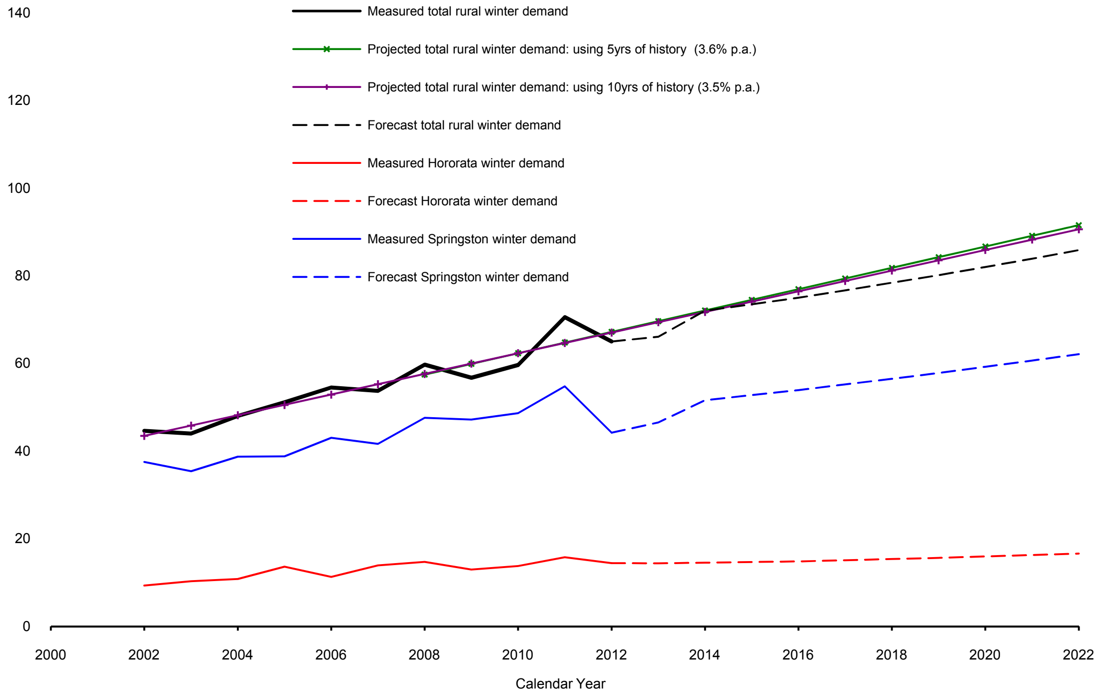
The following graph shows recent load growth in our rural area. Note the effects of load transfers from the Hororata GXP to the Springston GXP in FY09. The Hororata forecast shows the impact of the second drier at the Synlait milk processing plant near Dunsandel and the new Fonterra milk processing plant near Darfield. The new Fonterra plant is expected to grow quickly, requiring a new GXP to be created at Kimberley. This GXP will also cater for new load if required by the proposed large surface irrigation schemes e.g. Central Plains Water. The Springston forecast jump in FY15 is driven by Westland Milk Products proposed milk processing plant near Rolleston. A significant proportion of the approximately 50% forecast increase in rural peak demand over the next 10 years is due to the increase in milk processing capability.

Rural summer maximum demand (MW)



Rural winter load growth has been steady at approximately 3.5% per annum over the last 10 years. The 2011 peak is due to the August snow. The recent UDS indicates that significant growth is expected to continue around Rolleston and Lincoln townships. Updated post earthquake population forecasts for these towns are not available at the time of writing but Rolleston in particular is expected to grow faster than planned due to earthquake induced relocations. We forecast winter load growth to continue at 3.2% per year over the next 10 years.

Rural winter max demand (MW)



9.8.5 GXP and zone substation load forecasts

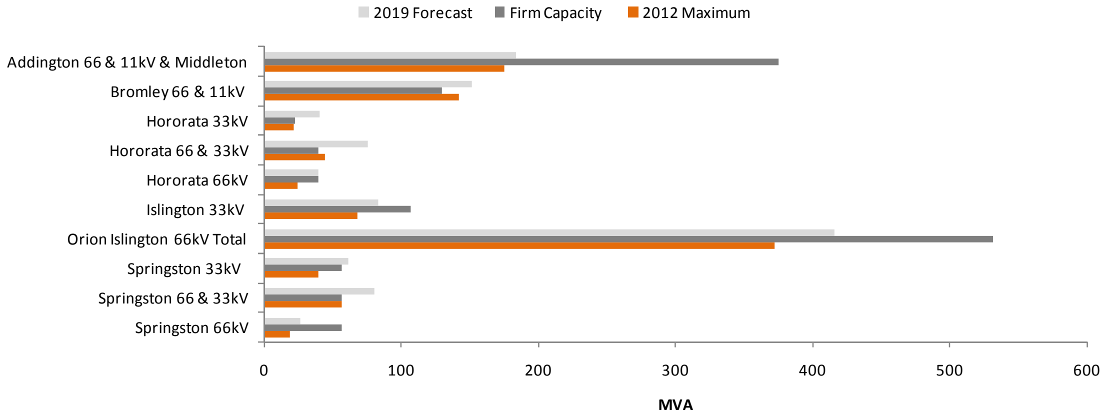
We estimate that future demand growth will average 1.0% (6MW) per annum over the CPP regulatory period, with some one-off additional business increases such as milk processing plants in the next few years. Significant volatility can be expected in actual maximum demands.

Transpower GXP load forecasts

The forecasts in the following sections have incorporated the impact of the earthquakes, including returning loads to their normal supply points. However, there is more uncertainty than usual due to ongoing depopulation, migration and the influx of temporary workers for the rebuild that is expected to last over five years.

The following graph indicates the capacity of each Transpower GXP that supplies our network. Present and expected maximum demands are also shown. The impact of projects incorporated in this CPP proposal is not reflected in the GXP load forecasts. The tabled loads are those expected if no development work is undertaken. Firm capacity is the capacity of each site should one item of plant fail. The notes to each chart describe the planned interventions to address forecast constraints.

GXPs – Maximum demand versus firm capacity



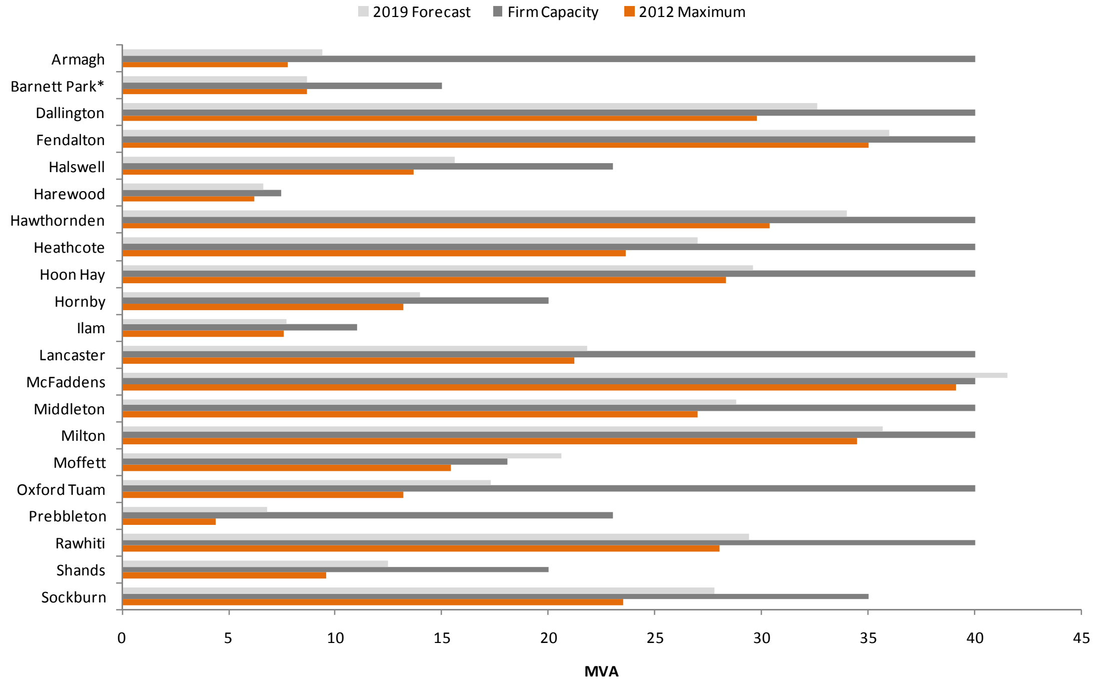
1. Bromley 220/66kV transformer planned upgrade to give 210MVA in FY13.
2. Horoata 66kV & 33kV capacity can be limited to 40MW when Coleridge is not generating or providing reactive support.
3. When Larcomb 66kV is in parallel with Springston the limit will increase to the 66/33kV transformer continuous rating of 59.4MVA.
4. Springston capacity to increase to ~110MVA when the parallel West loop from Islington via Weedons/Larcomb is completed.

GXP substation load forecasts (MVA)

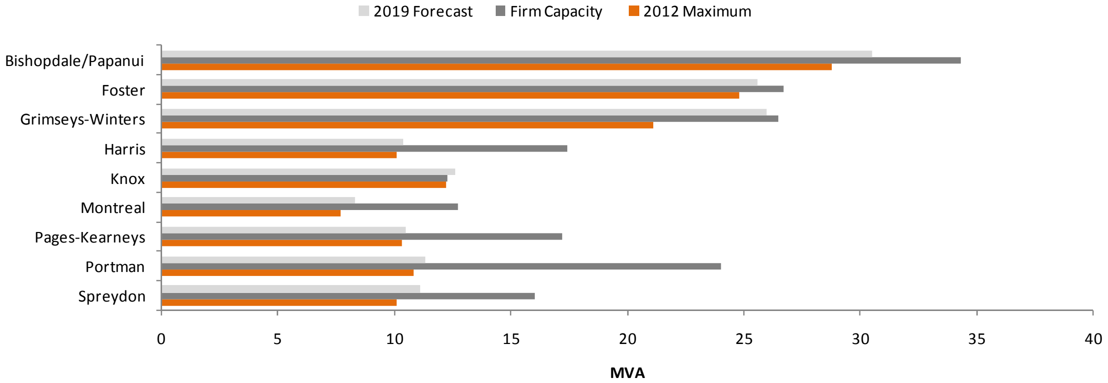
	Firm capacity	Winter 2012 or Summer FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Addington 66 & 11kV & Middleton	375	175	174	176	177	179	180	182	184	186	188	190
Bromley 66 & 11kV	130	142	146	147	148	148	149	150	151	152	153	155
Islington 33kV	107	68	71	73	74	76	79	81	83	85	87	89
Orion Islington 66kV Total	532	372	382	393	397	401	406	411	416	421	426	433
Hororata 33kV	23	22	28	33	34	36	41	41	41	42	42	44
Hororata 66kV	40	24	27	28	33	34	38	39	40	41	42	43
Hororata 66 & 33kV	40	44	52	58	62	66	73	75	76	77	79	82
Springston 33kV	57	40	45	46	54	55	56	60	61	62	62	63
Springston 66kV	57	19	21	25	25	25	26	26	26	27	27	27
Springston 66 & 33kV	57	57	61	65	73	74	76	79	80	81	82	83

Orion urban zone substation load forecasts

The following two graphs compare the firm capacity of each of our urban zone substations with present and forecast load. The winter 2012 value is the peak load recorded in June 2012.



Urban 11kV zone substations – maximum demand versus firm capacity



Notes:

* denotes a single transformer site

1. Moffett constraint to be resolved by Moffett 33kV feeder replacement.
2. McFaddens constraint to be resolved by new Marshlands zone substation.
3. Ilam zone substation is included with the 66 and 33kV substations although it is regarded as an 11kV zone substation elsewhere. This is because it has no transformers on site but has two dedicated 66/11kV transformers located at Hawthornden.
4. Knox constraint to be resolved by transferring load to Armagh zone substation.

Urban 66kV and 33kV zone substation load forecasts (MVA)

	Security std class	Firm capacity	Actual winter 2012	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Armagh	C1	40	8	8	8	9	9	9	9	9	10	10	10
Barnett Park	C4	15	9	9	9	9	9	9	9	9	9	9	9
Dallington	C2	40	30	31	31	32	32	32	32	33	33	33	34
Fendalton	C2	40	35	35	35	35	35	36	36	36	36	36	37
Halswell	C4	23	14	14	14	14	15	15	15	16	16	17	18
Harewood	C4	8	6	6	6	6	6	6	7	7	7	7	7
Hawthornden	C2	40	30	33	33	33	33	34	34	34	34	35	35
Heathcote	C2	40	24	24	24	25	25	26	26	27	27	28	28
Hoon Hay	C2	40	28	29	29	29	29	29	29	30	30	31	31
Hornby	C4	20	13	13	13	14	14	14	14	14	14	14	14
Ilam	C4	11	8	8	8	8	8	8	8	8	8	8	8
Lancaster	C1	40	21	21	21	21	22	22	22	22	22	22	22
McFaddens	C2	40	39	40	40	41	41	41	41	41	42	42	43
Middleton	C2	40	27	27	28	28	28	28	29	29	29	29	29
Milton	C2	40	34	35	35	35	35	35	36	36	36	36	36
Moffett	C2	18	15	16	17	18	18	19	20	21	21	22	23
Oxford-Tuam	C1	40	13	14	14	15	16	16	17	17	18	19	19
Prebbleton	C4	23	4	5	5	5	6	6	6	7	7	8	8
Rawhiti	C2	40	28	29	29	30	30	30	30	30	29	29	29
Shands	C4	20	10	10	10	11	11	12	12	12	13	13	14
Sockburn	C2	35	24	24	25	25	26	26	27	28	28	29	29

The security standard class referred to in these tables is described in Section 6.2.7.

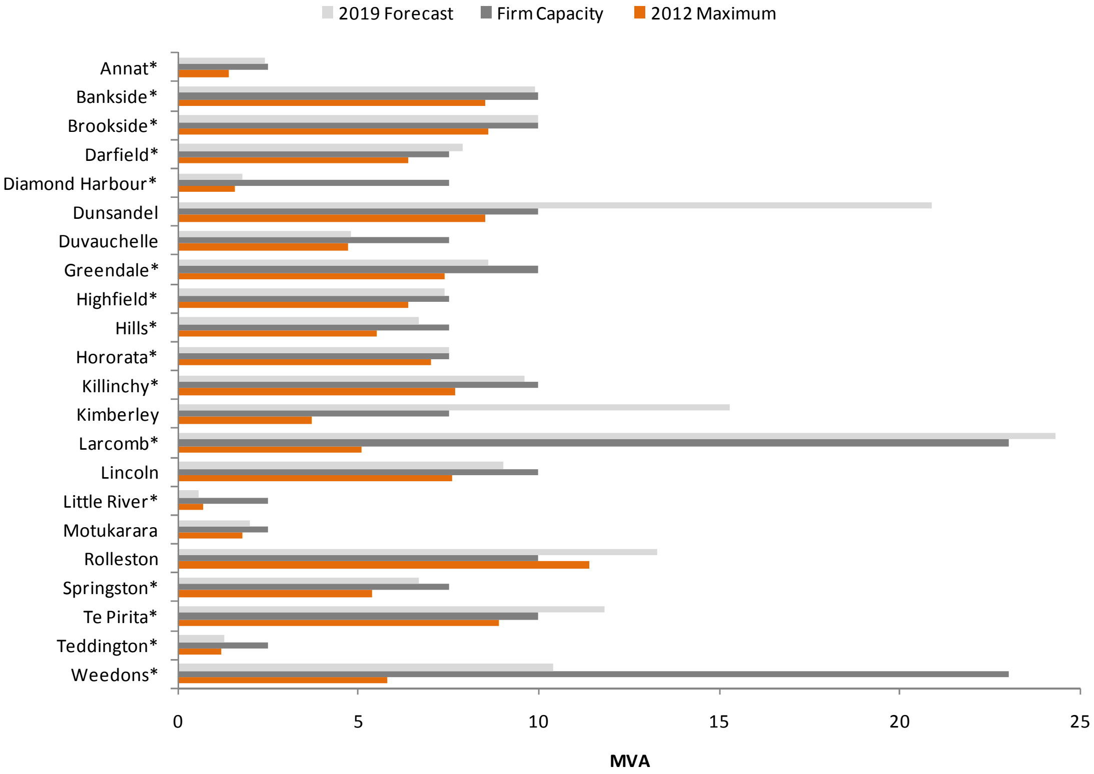
Urban 11kV zone substation load forecasts (MVA)

	Security std class	Firm capacity	Actual winter 2012	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Bishopdale/ Papanui	C2	34.3	29	29	29	30	30	30	30	31	31	31	31
Foster	C2	26.7	25	25	25	25	25	25	26	26	26	26	26
Grimseys-Winters	C2	26.5	21	22	23	24	24	25	25	26	27	27	28
Knox	C3	12.3	12	12	12	12	12	12	13	13	13	13	13
Montreal	C3	12.7	8	8	8	8	8	8	8	8	8	8	9
Pages-Kearneys	C4	17.2	10	10	10	10	10	10	10	11	11	11	11
Portman	C4	24.0	11	11	11	11	11	11	11	11	11	11	12
Spreydon	C4	16.0	10	10	10	10	11	11	11	11	11	12	12

Orion rural zone substation load forecasts

The following graph compares the firm capacity of each of our rural zone substations with present and forecast load. The winter 2012 value is the peak load recorded in June 2012.

Rural 66 and 33kV zone substations – maximum demand versus firm capacity



Notes:

* denotes a single transformer site

1. Hororata constraint to be resolved by increasing zone substation from 33 kV to 66 kV and the installation of Windwhistle substation.
2. Te Pirita constraint to be resolved in the longer term by the installation of Windwhistle.
3. Rolleston constraint to be resolved by shifting load to Larcomb zone substation.
4. Kimberley constraint to be resolved by new Kimberley GXP in the short term and new Creyke zone substation in the long term.
5. Dunsandel transformers will be replaced with 23MVA units.
6. Brookside constraint to be resolved with new Norwood zone substation.
7. Kimberley constraint to be resolved by transferring load to Weedons zone substation

Rural 66 and 33kV zone substations load forecasts (MVA)

	Security std class	Firm capacity	Actual Winter 2012 / Summer FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
Annat	D3	2.5	1.4	1.7	1.7	1.8	2.4	2.4	2.4	2.4	2.4	2.5	4.3
Bankside	D2	10.0	8.5	9.2	9.3	9.4	9.6	9.7	9.8	9.9	10.0	10.1	10.2
Brookside 66kV	D2	10.0	98.6	9.3	9.4	9.5	9.6	9.7	9.9	10.0	10.1	10.2	10.3
Darfield	D2	7.5	6.4	7.0	7.2	7.3	7.4	7.6	7.8	7.9	8.1	8.3	8.5
Diamond Harbour	D3	7.5	1.6	1.6	1.7	1.7	1.7	1.7	1.8	1.8	1.9	1.9	2.0
Dunsandel	D2	10.0	8.5	9.9	10.8	14.6	15.4	19.3	20.1	20.9	21.8	22.6	23.4
Duvauchelle	D2	7.5	4.7	4.7	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.9
Greendale	D2	10.0	7.4	8.0	8.1	8.2	8.3	8.4	8.5	8.6	8.7	8.8	8.9
Highfield	D2	7.5	6.4	6.9	7.0	7.1	7.2	7.3	7.4	7.4	7.5	7.6	7.7
Hills	D2	7.5	5.5	6.0	6.1	6.2	6.3	6.5	6.6	6.7	6.8	6.9	7.0
Hororata	D2	7.5	7.0	6.9	7.0	7.1	7.2	7.3	7.4	7.5	7.6	7.7	7.8
Killinchy	D2	10.0	7.7	8.5	8.6	8.8	9.0	9.2	9.4	9.6	9.8	10.0	10.2
Kimberley	D1	7.5	3.7	4.6	9.6	9.6	11.3	15.3	15.3	15.3	15.3	15.3	15.3
Larcomb	D3	7.5	5.1	5.9	10.4	19.7	19.9	21.0	24.1	24.3	24.5	24.7	24.9
Lincoln	D2	10.0	7.6	7.6	7.8	8.0	8.3	8.5	8.7	9.0	9.3	9.6	9.9
Little River	D3	2.5	0.7	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Motukarara	D3	2.5	1.8	1.9	2.0	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1
Rolleston	D2	10.0	11.4	11.4	11.8	12.1	12.3	12.6	13.0	13.3	13.7	14.1	14.5
Springston	D2	7.5	5.4	6.4	6.5	6.5	6.6	6.6	6.7	6.7	6.8	6.8	6.9
Teddington	D3	2.5	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3
Te Pirita	D2	10.0	8.9	10.0	10.4	11.1	11.2	11.3	11.6	11.8	11.9	12.0	12.1
Weedons	D2	7.5	5.8	5.8	10.1	10.1	10.2	10.3	10.3	10.4	10.4	10.5	10.5

The security standard class referred to in this table is described in Section 6.2.7.

9.8.6 Meeting Schedule D6 information requirements

Scheduled D of the CPP IM sets out particular information requirements in respect of demand, consumer number and generation forecasts that must be included in a CPP proposal. These requirements do not replicate our demand forecasting approach, models and assumptions. Accordingly, in order to demonstrate our compliance with the intent of Schedule D6 we provide the following commentary with reference to the D6 information requirements.

Schedule D6

Requirement	Explanation
(1)(a) How key assumptions are relied upon in the CPP proposal	Key assumptions are used to derive annual load growth projections at each GXP and zone substation. These are used to determine the nature and timing of the forecast major projects and reinforcement projects which are set out in Sections 9.13 and 9.14 below. The timing and nature of our major projects is also reflected in our proposed reliability standards, as described in Section 6. These are consistent with our service measure targets described in Section 9.6. The assumptions underpinning the load growth projections are also relevant to our forecast quantities, which are described in Section 7.2.5.
(1)(b) Methodology for demand forecasts (to zone substation level)	This is described in NW70.60.12. A summary is also presented in Sections 9.8.2 and 9.8.3 above
(i) sensitivity analysis	Sensitivity analysis is not undertaken. Forecasts are updated each year to take account of load forecast changes
(ii) weather normalisation	We normalise our GXP and zone substation peak demand values to correct for weather variances. We use a normal year for our forecasts but include an extreme peak forecast for assessing the GXPs
(iii) models used	Refer to NW70.60.12 for a description of the models used
(c)(i) treatment of large loads, uncertain loads and significant loads transferred	Our load forecasting spreadsheet includes processes for transferring 11kV load. Where a zone substation is forecast to be overloaded, we look for opportunities to transfer load either by switching or by implementing economic 11kV reinforcement projects to defer subtransmission investment. Refer NW70.60.12
(c)(ii) consumer numbers and categories	Residential population data is used for load forecasting, as described in Sections 9.8.2 and 9.8.3. Consumer numbers are not used for this purpose. Refer Section 7.2.5 for consumer number forecasts for revenue purposes
(c)(iii) energy volumes supplied to consumers by category	This information is not used for demand projections. Refer Section 7.2.5 for consumer number forecasts for revenue purposes

(c)(iv) average consumer energy use by category	This information is not used for demand projections. Refer Section 7.2.5 for forecasts for revenue purposes
(v) details of embedded generators	There are no embedded generators on our network
(vi) details of distributed generation (DG) and impact on network forecasts	Because all of the DG on our network is fairly small (on a site and unit basis) we treat them as a negative load and apply normal N-1 planning criteria. That is, we do not plan on an N-1-G or N-G basis. More information is provided in Section 9.13.9 below which describes our non network solutions
(vii) details of DMS and impact on forecasts	This is addressed in Section 9.8.2 above
(2)(a) extent of consistency between forecast method and historical observations	Our load forecasts are consistent with historical observations. The future is not expected to deviate radically from the past. The earthquakes have resulted in a step change setback in demand and a slightly lumpy growth rate over the next few years but the forecast overall growth rate is largely consistent with historical trends. Other factors (e.g. the CAP and electric vehicles) are considered in the forecasts although they are not expected to have a significant impact during the CPP period
(2)(b) internal consistency at and between each level of aggregation to zone substation level	We normalise the network peak, GXP and zone substation forecasts. This is explained in NW70.60.12
2(c) consistency between forecast method and that used for forecast quantities (clause 5.3.4(7))	The underlying assumptions and projection methods used in both forecasts are the same (ie: the UDS scenarios for population growth). The models and outputs differ however for the reasons described above, and explained further below. Refer to further explanation in Section 7.2.5. We note that typically, the focus of the revenue projections is the following financial year, while the planning (demand) projections are looking out 10 to 20 years. Revenue projections can (and should) take account of apparent shorter term influences, whereas planning need not. Moreover, while the planning projections can be expressed at a high level (eg total energy delivered through the network) and this is broadly comparable with at least some chargeable quantity projections, the actual planning is based on forecasts for many different parts of the network. We note that the trends and forecasts in this section of the proposal are indeed broadly similar where they are comparable. For example a (pre-earthquake) trend rate of growth in delivered energy volumes (over 30 years) of around 1.9% per annum, which is consistent with the historical analysis in Section 7.2.5 which has a long term growth rate (over 13 years) of 1.8%. As the various volume graphs show, there is significant variation from the long term trend over shorter periods within it. The planning demand (MW) history and forecasts (when expressed as a

single network wide number) are of a single maximum half hourly demand and are inherently volatile. The revenue demand components (there are separate ones for general, streetlighting and major customer categories) are measured over a much larger number of half hours, and are both less volatile, and therefore not directly comparable. Nevertheless the 1.1% pre-earthquake trend rate of growth in maximum demands aligns well with a context of slightly slower growth post earthquake.

Perhaps most importantly, not all growth is equally significant from a revenue perspective. As an extreme example, the doubling in capacity at the Fonterra Darfield site that is planned for around June 2013 will actually reduce our distribution revenue, as they are moving to a solution that is effectively a direct connection to the Transpower grid.

9.9 Risk management

IMD10(c)

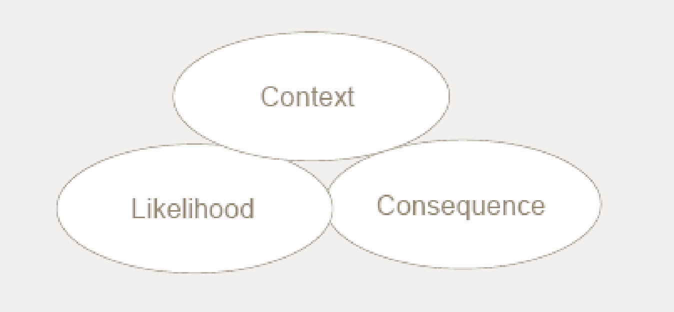
9.9.1 Introduction

Risk management context

To be a sustainable business, we perform risk management to identify risk and determine acceptable levels of risk. Risk needs to be understood and, where it cannot be eliminated, we use training, competency, safe work practices and network design to manage and mitigate the level of risk. We can mitigate risks within acceptable limits to achieve the most satisfactory outcome.

Risk is often measured or quantified as the product of a probability and consequence, however, a less obvious but important factor is context. While the severity of some risks may appear similar, their contexts may be quite different.

The three components of risk



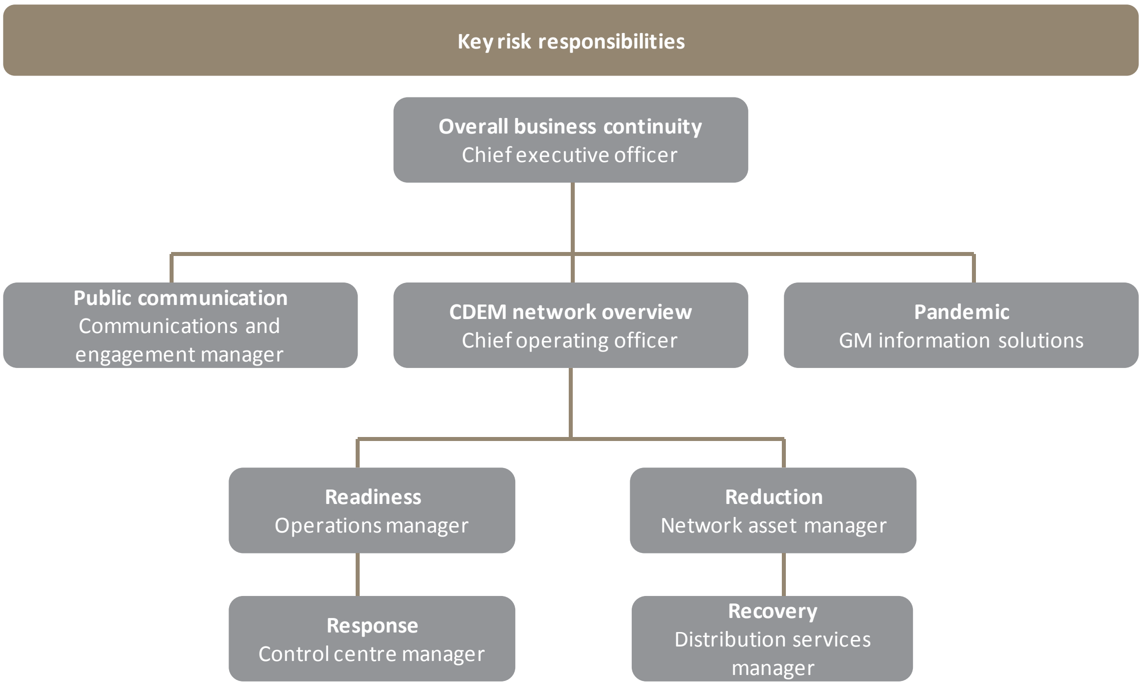
Risk management responsibilities

The Orion board is ultimately responsible for our risk management. To manage this obligation the board approves our annual statement of intent, our annual business plan and our asset management plans.

Our board has established an audit committee to liaise with Orion's auditor and provide additional assurance regarding the quality and reliability of internal controls for financial information used by and issued by the board.

Operational business risk management is the responsibility of the CEO and his management team but it is overseen by the Orion board. Key operational risks are delegated to business group managers. Some risks are common to all business groups but generally key risks are directly managed by the group with the greatest expertise.

The following chart shows the responsibilities of key Orion staff who help to identify and manage risk. These responsibilities help us to plan and respond to situations that may arise from any of the causes discussed in the remainder of this section. We have aligned our civil defence responsibilities using the 'four Rs' approach to resilience planning - reduction, readiness, response and recovery.

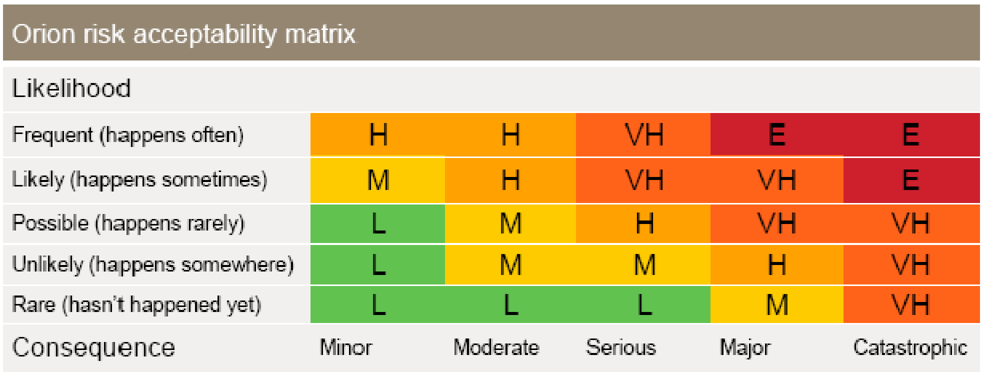


Risk management process

Our risk management process is based on the risk management standard AS/NZISO31000: 2009. The acceptability of risk is determined on the basis of likelihood and consequences of the event associated with the risk occurring. The evaluated ranking of these two is used to establish the priority for managing the risk. We have two risk assessment tools, both of which have been calibrated to present the risk acceptability ranking in a similar manner:

- desktop - paper based work area assessment utilising the risk acceptability matrix below

- quantate - a dedicated risk management software application that allows us to prioritise risk across our business with results presented on the bands of the risk acceptability chart below.

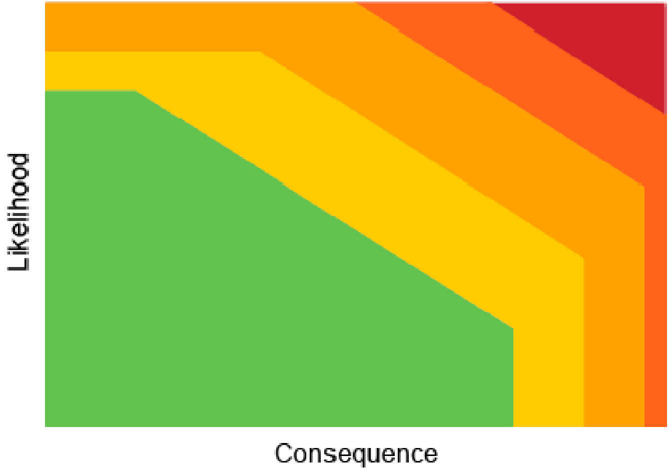


Orion risk acceptability matrix

Likelihood					
Frequent (happens often)	H	H	VH	E	E
Likely (happens sometimes)	M	H	VH	VH	E
Possible (happens rarely)	L	M	H	VH	VH
Unlikely (happens somewhere)	L	M	M	H	VH
Rare (hasn't happened yet)	L	L	L	M	VH
Consequence	Minor	Moderate	Serious	Major	Catastrophic

Classification	Escalation
E = Extreme	Board to be informed
VH = Very high	CEO to be informed
H = High	Corporate manager to be informed
M = Moderate	Line manager to be informed
L = Low	No escalation

Orion risk acceptability chart



9.9.2 Risk management policies and plans

IMD10(c)(i)

We have a number of risk management policies and plans for different aspects of our business. We summarise these below:

Disaster resilience summary (NW70.00.14)

We created this document to inform Civil Defence and others of our network resilience.

Asset risk management plan (NW70.60.02)

The Civil Defence Emergency Management Act also requires us to plan for major events that affect the environment. In particular it requires us to:

- function to the fullest extent during and after an emergency
- hold plans which show how we plan to function during and after an emergency
- participate in civil defence emergency planning at national and regional level if requested
- provide technical advice on civil defence emergency management issues where required.

As part of these requirements, our asset risk management plan focuses on the physical aspects of risk associated with managing network assets in the event of a major incident or emergency. Topics covered include:

- exposure to natural disaster with details of specific hazards
- establishing a rating system to easily identify those areas most at risk
- mitigation measures and practical solutions to reduce risk or impact
- the location, likely reasons for failure and contingency provisions for each asset group
- a schedule of the risk-based spares we hold.

Security standard

Our security standard is key to how we plan to meet the demand for electricity in certain circumstances when electrical equipment fails on our network. It is discussed in detail in 6.2.7.

Network physical access security plan (NW70.60.03)

Our network physical access security plan details our security policies, principles and procedures that restrict physical access to our electrical network and associated infrastructure. The principles defined in this document underpin our stated commitment to provide a reliable network and a safe and healthy work environment for the public, employees and contractors.

The predominant focus of the plan is to restrict access by unauthorised personnel. However, some of the consequences and dangers associated with access to equipment, together with mitigation measures, also directly affect authorised personnel. In terms of security, the general principle is to prevent unauthorised entry by the public and opportunist intruders without specialised tools, and slow determined intruders.

This is achieved by:

- reasonable measures to prevent access by members of the public to potentially fatal voltages
- additional measures to deter, detect and slow determined intruders at higher risk sites.

Environmental risk register (NW70.10.06)

The aim of this register is to summarise the environmental risks that relate to our business and operations, including likelihood of occurrence, consequences and mitigation.

Environmental risks associated with loss of supply or fluctuations in supply are not included, either generally, or in relation to particular large industrial users. At this stage we consider these risks are more appropriately addressed through the asset management process, Lifelines Project and individual users' own environmental risk assessments.

We have assessed risk likelihood, consequence and mitigation-effectiveness based on subjective estimate. This assessment is therefore not supported by historical data or records. The register is a tool that helps us to manage risk – it is not an exhaustive list of all risks. Its value is that it identifies general risk to the company and highlights any areas of high risk that may require particular management attention.

Business continuity plans

The aim of these plans is to provide an assessment of the risks that relate to the continuity of our business and operations due to the loss of systems or personnel. Each corporate manager is responsible for their functional part of these plans.

9.9.3 Risk assessments and mitigation measures

IMD10(c)(ii) and (iii)

Clause D10(c) requires a description of risk assessments, risk mitigation and prevention measures employed during the current period and those proposed to be deployed in the next period.

As our risk assessment approach continually evolves, our description below presents how Orion’s assessments and measures have been established, have evolved and areas where we are planning for investigation. We have also included explanations for obligations which are relevant to our risk assessments, and how these have changed during the current period.

We have assessed our greatest risks as:

- safety
- legislative compliance
- commercial management
- reputation
- environment
- human resources
- network performance (addressed in 9.9.4 and 9.9.5 below).

We describe these key risks below, including a description of the risk mitigation measures we have implemented.

Safety

It is not possible to entirely eliminate all safety hazards. However, we are committed to providing a safe, reliable network and a healthy work environment.

We take all practical steps to ensure that our staff, the community and the environment are not at risk. We control hazards through training, guidelines and standards. Potential hazards, in particular electrical hazards, must also be considered when new network installations are being designed and constructed. This objective is consistent with our service level targets for no lost time accidents or injuries to our staff, contractors or the public as a result of working or living in or around our assets.

Legacy assets

With long life networks there are inevitably a number of legacy assets that do not meet current operational or safety standards. When we become aware of assets or safety issues that do not meet modern expectations, we prioritise mitigation measures to reduce the risk to both the general public and our workers. These actions may include full replacement over time or may include strategies to reduce risk until replacement can be achieved. Key areas where we are currently managing these types of risk are our:

- low voltage panels at our older substations
- low voltage panels at our older link-boxes
- legacy low voltage system where service mains are t-jointed into our distribution network.

Employees

We are committed to consultation and co-operation between management and employees. Maintaining a safe, healthy work environment benefits everyone and is achieved through co-operative effort.

We focus on line managers taking responsibility for themselves and their employees to manage hazards which may be present in their work areas. We have introduced risk based hazard assessment to our staff. Our systems systematically identify, assess and manage potential hazards in the work place. Our Health, Safety and Environment Committee and support from health and safety practitioners are also important.

Contractors

Since almost all work associated with our network is carried out by contractors, we have developed registers of specific known hazards along with recommended actions to control hazards. Contractors must have their own documented health and safety management systems and they are further reminded of their health and safety obligations when they sign a new contract. We carry out regular site audits to ensure compliance.

Most hazards can be managed if access to hazardous areas is restricted to competent personnel, and industry-recognised safe working practises are used.

Public

We monitor concerns about health and electrical fields and run community education courses teaching children to stay safe around electricity. We also run an ongoing advertising campaign to promote public safety around our network.

We recently engaged an independent consultant to undertake a risk analysis of security where access to our network could be considered a significant hazard to the public.

As a general principle, significant electrical hazards within the public arena are controlled using two barriers of protection. Signage on the initial locked barrier alerts visitors to the general hazard and that access is restricted to authorised personnel only. The second barrier has further warning signage and a barrier preventing inadvertent contact with the hazard. The form of the barriers may differ depending on the level of risk and the practicality of implementation.

We recently won the ‘Electricity Engineers Safety Award for Public Safety’ for our risk based approach to public safety.

Legislative compliance

Material compliance is assessed using standard risk assessment methods to prioritise and quantify our known risks. As part of our regular reporting to the board, specific issues associated with our compliance programmes are reported. The following Acts and Regulations are those that we consider key to the management of our business:

- Electricity Act 1992
- Electricity Industry Act 2010
- Electricity Regulations 1997
- Electricity Governance Rules
- Commerce Act 1986
- Resource Management Act 1991
- Hazardous Substances and New Organisms Act 1996
- Health and Safety in Employment Act 1992
- Building Act 2004
- Fire Service Act 1975
- Fire Safety and Evacuation of Buildings Regulations 1997
- Commerce Act 1986
- Companies Act 1993
- Energy Companies Act 1992
- Electricity Industry Reform Act 1998
- Financial Reporting Act 1993
- Taxation Legislation
- Consumer Guarantees Act 1993
- Fair Trading Act 1986
- Sale of Goods Act 1908
- Employment Relations Act 2000
- Holidays Act 2003
- Human Rights Act 1993
- Injury Prevention, Rehabilitation and Compensation Act 2001

- Minimum Wage Act 1983
- Wages Protection Act 1983
- Parental Leave and Employment Protection Act 1987
- Smoke Free Environments Act 1990
- Privacy Act 1993.

Commercial management

The commercial management of Orion includes governance, finance, insurance, auditing, pricing, valuation, industry submissions and information technology.

Ensuring that sufficient financial resources are available to support the continued operation, maintenance, replacement and growth of the network is a key task of management. Central to this is managing revenue risk and the relationship between cost and income. Several activities assist in the management of this risk including prudential requirements, managing contracts and potential liabilities, matching pricing to cost drivers (eg: via peak pricing) and participating in developments to the Part 4 regulatory regime.

Reputation

We value our reputation and relationship with our customers and aim to be recognised for excellence in customer service and stakeholder relationships, lead collaboration across the electricity industry for the benefit of all, apply technology and demand side management to benefit our customers, and be recognised for excellence in leadership and management. To achieve these aims we have developed the following values:

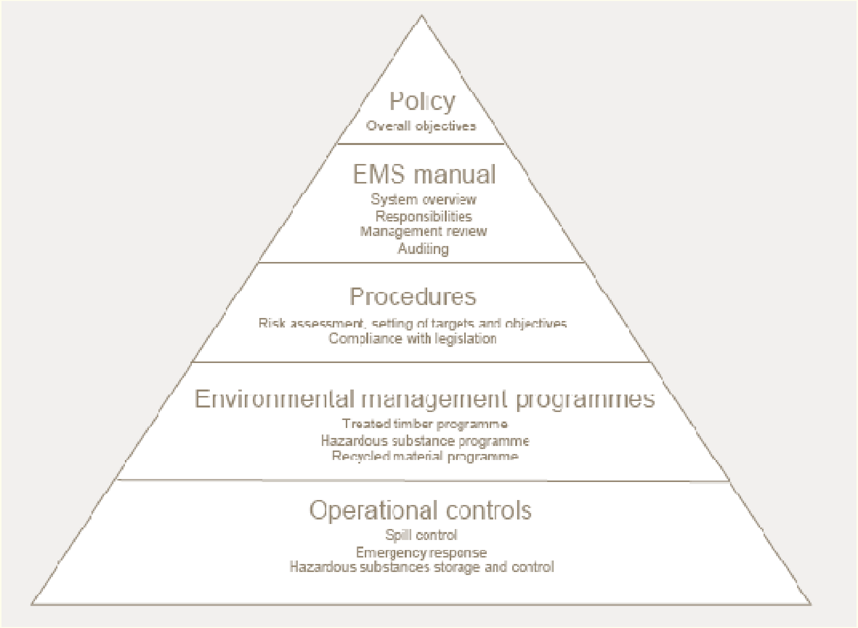
Our values	
We will	**Meaning**
Value relationships	We build and maintain positive relationships with our internal and external stakeholders (our employees, customers, shareholders, suppliers, contractors, regulators, community organisations etc)
Be trustworthy	We demonstrate honesty, sound judgement, understanding and empathy. We earn the trust and respect of our community
Be proactive	We create opportunities and promptly respond to challenges with initiative. We empower our employees to be accountable and focus on results
Maintain a long term focus	Decisions we make must not compromise the achievement of our purpose
Be effective and efficient	We strive for competence, effective planning and execution, consistency in application and efficiency
Be innovative	We maintain a learning environment. We explore and adopt ideas that create value

Value safety and wellbeing	We provide a safe and healthy work environment to protect ourselves, other people and property
Value our natural environment	We are mindful of our impact on the natural environment and seek ways to minimise our effects

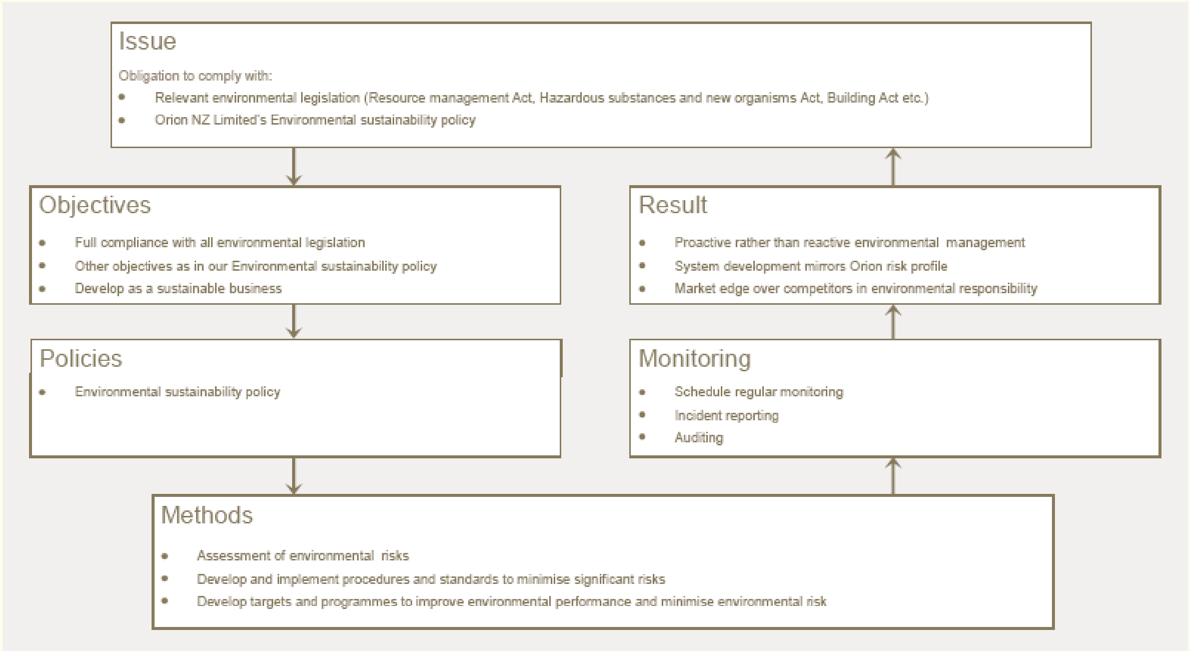
Environment

We follow a policy of environmental sustainability, initiate energy efficiency programmes and work to minimise electrical losses on our network wherever possible. Our environmental sustainability policy covers protection of the biosphere, sustainable use of natural resources, reduction and disposal of waste, wise use of energy, risk reduction, restoration of environment, disclosure, commitment of management resources, stakeholder consultation, assessment and annual audit. Our documentation and environmental management processes are illustrated below.

Environmental management documentation



Environmental management process



Several years ago we implemented specific management systems for:

- SF_6 gas - NW70.10.01 SF_6 gas management procedures
- Oil and fuel - NW70.10.02 environmental management procedures for oil and fuel.

We have successfully managed any significant spills. These objectives are reflected in our service level targets set out in Section 9.6.4 above.

Energy efficiency programmes

We instigate and/or provide continuing support for energy efficiency programmes such as our:

- Community energy action charitable trust (CEA) (cea.co.nz)
- Ecobulb CFL promotion.

Environmental sustainability commitment

Other aspects of our operations that support our environmental commitment are that we:

- facilitate the easy connection of renewable low-carbon generation (for example wind power) to our network
- signal load peaks in our network pricing to encourage the efficient use of our network
- maintain and operate an efficient water cylinder load control system so that significant loads can be shifted away from peak times to less expensive off peak times, at minimal inconvenience to customers
- are looking at possible wind generation sites in our network area.

Environmental targets

In 2008 we undertook a study, in conjunction with international consulting firm MWH, to map our key impact on the environment and then assess the feasibility of becoming carbon neutral. MWH's report found that the overwhelming majority of our annual carbon footprint comes from two main sources:

- 77% from electrical losses on our network (electrical losses are natural phenomena that are caused by the heating of equipment as electricity passes through)
- 17% from carbon embedded in our physical electricity distribution network assets.

The MWH report also found that there is little we can do to significantly reduce our carbon footprint from either of the above two sources. The following targets have been set after consultation with MWH on where the best gains can be made:

- incorporate the cost of carbon into our network investment decisions (June 2009)
- continue to undertake and encourage demand side management (ongoing)
- reduce and where practical eliminate the installation of new network cables containing lead (ongoing)
- undertake a safety and efficiency driving course for all Orion and Connetics employees who regularly drive operational vehicles (March 2011)
- consider the potential to replace operational vehicles in the Orion and Connetics fleet with more fuel efficient models. We also will work with other contractors servicing the Orion network to encourage them to run their vehicle fleet as efficiently as possible (March 2011)
- assess the feasibility and desirability of becoming carbon neutral (September 2009)
- continue our support for and sponsorship of CEA (ongoing)
- work with CEA to insulate at least 500 low income homes in Christchurch (March 2010)
- support the CCC's sustainable energy strategy (ongoing).

Human resources

A sophisticated network of electrical assets is central to how we function. The skilled employees who plan and operate this equipment are also critical to our business.

We aim to provide a work environment that enables professional and personal growth - we recognise our responsibility to ensure our people achieve the best mix of skills they can while they are here. An aging workforce and an industry shortage of skilled staff remain issues and we continue to plan ahead to recruit and retain skilled employees. To ensure that we are not short of skilled employees in the future, we support several initiatives that focus on training, recruitment and staff retention:

- In-house trainee programmes - these programmes are designed to train employees to a level where they are sufficiently skilled to replace employees who we expect to retire in the next five to 10 years
- CPIT Trades Innovation Centre - we continue to advise on ways to retain and attract people into electricity related trades. We have invested in a distribution trades training centre as a partner with CPIT
- Power Engineering Excellence Trust - the Trust and University of Canterbury have established an Electric Power Engineering Centre to support power engineering education

- Wellness programme - our wellness programme helps our employees maintain good standards of health. Wellness activities include; regular health and wellbeing seminars, on-site health nurse, full health checks, flu vaccinations, fitness activities, healthy eating lunches, employee counselling and subsidised visual examinations

As an employer committed to developing the potential of our employees we believe it is important to understand their concerns. Each year we survey our employees to obtain their views on their working environment.

Financial management

We have a number of policies and procedures which ensure our financial risks are managed prudently. These comprise financial and internal controls including delegated authorities and a number of related policies (for example credit card, travel, fleet, tax). These are listed in NW70.50.03.

9.9.4 Risk assessments – network performance

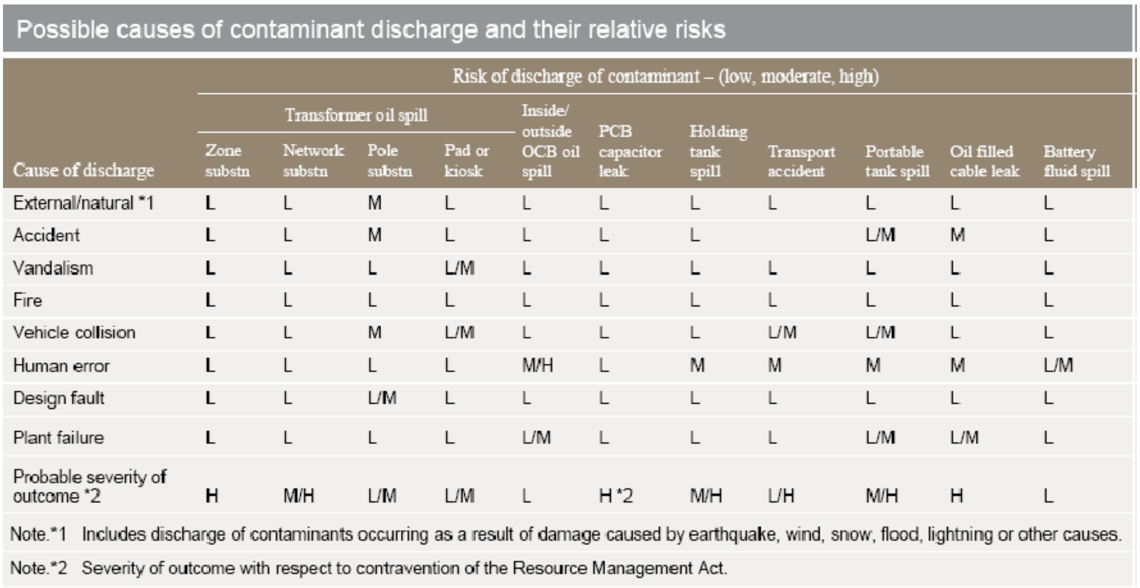
We assess critical assets for risk to clearly establish the impact of asset failure, based on expected failure rates for given assets. This work includes the likely impact or consequence of failure and takes into account aspects such as the availability of equipment and the lead time required to purchase replacement equipment. This, coupled with the impact from the most credible natural events, establishes the justifiable spares levels.

The need for spares is created by the likelihood of two events in addition to average failure mode levels. These additional events are earthquakes (65% chance in the next 50 years) and storm conditions (100% chance in the next 50 years).

Earthquakes create the most significant risk to our network, since both likelihood and consequence is high and long equipment replacement times are a major consideration. We are having another look at our earthquake risk in the light of what we now know after the September 2010 and February 2011 earthquakes. These recent earthquakes have given us new data that we now need to consider.

Primary risk for major assets

Asset	Type	Main risk
Cables	All	Earthquake
Lines	All	Storm
Switchgear	All	Earthquake
Transformers	Ground mounted	Earthquake
	Pole mounted	Lightning
	With auto tapchanger	Earthquake
	Regulator	Earthquake



Possible causes of contaminant discharge and their relative risks

Cause of discharge	Risk of discharge of contaminant – (low, moderate, high)										
	Transformer oil spill				Inside/ outside OCB oil spill	PCB capacitor leak	Holding tank spill	Transport accident	Portable tank spill	Oil filled cable leak	Battery fluid spill
	Zone substn	Network substn	Pole substn	Pad or kiosk							
External/natural *1	L	L	M	L	L	L	L	L	L	L	L
Accident	L	L	M	L	L	L	L		L/M	M	L
Vandalism	L	L	L	L/M	L	L	L	L	L	L	L
Fire	L	L	L	L	L	L	L	L	L	L	L
Vehicle collision	L	L	M	L/M	L	L	L	L/M	L/M	L	L
Human error	L	L	L	L	M/H	L	M	M	M	M	L/M
Design fault	L	L	L/M	L	L	L	L	L	L	L	L
Plant failure	L	L	L	L	L/M	L	L	L	L/M	L/M	L
Probable severity of outcome *2	H	M/H	L/M	L/M	L	H *2	M/H	L/H	M/H	H	L

Note.*1 Includes discharge of contaminants occurring as a result of damage caused by earthquake, wind, snow, flood, lightning or other causes.

Note.*2 Severity of outcome with respect to contravention of the Resource Management Act.

Interdependence with other service providers

Many service organisations rely on the services of others to perform. In particular, communication systems are of critical importance to all lifeline utilities. It is important to understand this ‘interdependence’ in the recovery stage of any disaster. We have considered interdependencies as part of a lifelines study on how natural disasters would affect Christchurch. As we have now experienced a ‘real’ event, as opposed to a ’hypothetical’ one, we will review our interdependence assessments within the lifeline utilities environment.

One emerging issue is the consolidation of fuel supply storage from contractors’ yards and small local service stations to larger centralised service stations. These stations have electronic controlled pumps that depend on a power supply for their operation. In the past it was normal to have local in-ground fuel tanks available to be used in an emergency, thus minimising our reliance on external supply for at least a few days. This is not the case today largely due to compliance with the Resource Management Act and costs associated with holding fuel reserves. Restoration after a disaster, such as an earthquake, has a very high dependence on an adequate fuel supply.

Transpower’s transmission lines, buildings and equipment have in general been designed and strengthened to withstand damage from most credible hazard events, with minimal damage. However, notwithstanding this, the ground conditions at three of Transpower’s sites may be susceptible to liquefaction, which could result in relatively significant differential settlement. While this may cause some problems in the switchyards, the major problems would be damage to control buildings and underground cables.

Support from non-liquefiable ground could reduce the vulnerability of cables to damage although this would be a very costly remedy. A more practical solution is to build diversity into future network development.

After the 4 September 2010 earthquake, minimal damage to equipment was observed. Supply was interrupted at three of Transpower's major GXPs and one minor GXP and constrained at one further GXP. Supply was able to be restored at all the major GXPs within three hours of the earthquake. Liquefaction was observed at Papanui GXP but had relatively minor consequences. After the 22 February 2011 earthquake, damage to equipment was observed and supply interrupted for five hours at Bromley GXP. Liquefaction was minor and most damage was due to severe shaking.

Network performance - natural disaster

Orion is a founding member of the steering committee of the Canterbury engineering lifelines group. The purpose of this group is to increase the resilience of Canterbury's infrastructure and to assist lifeline utilities to participate in all phases of civil defence emergency management.

Our integrated emergency management approach is based around the four Rs - reduction, readiness, response and recovery as follows:

Integrated emergency management

Four Rs	Explanation
Reduction	Risk management is an integral component of the reduction phase; identifying and analysing risks and developing plans and systems to reduce risk. As part of this process we analyse and identify the probability, magnitude and consequences of risk. We also establish what are acceptable levels of risk.
Readiness	This involves developing operational systems and capabilities before an emergency happens. We maintain a range of plans and documents in readiness for an emergency, including an asset risk management plan, major outage communication plan, contact lists for the electricity industry and emergency contractors and a recovery plan. We regularly contribute to emergency readiness programmes. We have a backup control centre so we can continue to function if anything happens to our primary control centre.
Response	In our response to emergencies, our first concern is the preservation of life. The safety of the public, contractors and staff is paramount. During an emergency situation we assess the scale of the event before planning our response. We have operational procedures in place detailing the actions we need to take immediately before, during and directly after an emergency. We have contingency plans in place for natural event/equipment failure, supply of emergency generators, loss of supply to the CBD, zone substations and GXPs, and energy shortage (rolling power cuts). Communication is the key to recovery after a disaster. The most secure of our communication systems is our own radio network installed in key Orion vehicles and emergency contractors' vehicles. We have also entered into a mutual aid arrangement with several other power companies.

Recovery	This involves rehabilitation and restoration to provide original functionality of the Orion network. As part of our recovery plan for an emergency situation, we review our customers' needs and our interdependencies with other services, and set priorities to restore full functionality. During and after an emergency situation, we provide regular updates to keep the public and stakeholders informed; advise them of the severity of the problem and likely time to restoration. Customers and suppliers are also advised of any situation on our website, which is updated on a regular basis.

Earthquakes and storms are our major natural event risks. We continue to invest significant time and money to ensure our network is prepared for such events. During the mid 1990s our network was part of an 'engineering lifelines' study into how natural disasters would affect Christchurch. Since this study, further detailed studies have been undertaken and we have minimised the overall risk to our network in a cost-effective manner.

After the 2010/2011 Canterbury earthquakes we commissioned Kestrel Group to carry out an independent review of how we performed. Kestrel's review covered our prior planning and prior risk mitigation measures, our preparedness and our emergency response. A summary of their findings is presented in Section 3.2.4. We are now carefully considering Kestrel's report and recommendations as part of our ongoing asset management and planning.

We have addressed risk to communications at the two main communication sites – Sugarloaf and Marleys Hill. Sugarloaf is operated by others and takes its primary power supply from our urban network. This site has generator backup. We have replaced this overhead line with a cable to make it more secure. The adjacent site at Marleys Hill has many operators. Key operators at the site have a backup power supply. Primary power supply is from our rural network which diversifies the source of power to our two main lifeline communication sites.

We have replaced the 'most at risk' section of the overhead line supplying Marleys Hill with underground cable. Lyttelton port is an important lifelines site. We have also installed a cable to allow the airport to be supplied by both Harewood and Hawthornden zone substations. This dual feed improves security of supply to the airport, an important lifelines site.

Although we have had several significant earthquakes and thousands of aftershocks during 2010 and 2011, there still remains a 1 in 123 chance that an earthquake on the Alpine Fault of magnitude 8 will occur in any year.

Liquefaction hazard evaluation

In 1998 we engaged Soils and Foundations (geotechnical consulting engineers) to evaluate the liquefaction hazard at key substation sites. Based on knowledge of local ground conditions, the following sites were selected as potentially sitting on liquefiable material: Addington GXP, Bromley GXP and Brighton, Paqes, Armagh, Dallington, Heathcote, Milton, Portman and Lancaster zone substations.

The engineers estimated the most severe form of damage due to liquefaction would be complete foundation failure of the substation buildings, towers and associated structures. A less severe, but more likely cause of damage, is post-earthquake settlement. The potential for liquefaction and liquefaction-related damage is summarised in the table below.

Note that the earthquake events used to assess the probability of liquefaction hazard in the study were taken from the seismicity model developed by Elder et al in 1991 and subsequently amended in 1993. During the 2010/2011 earthquakes, liquefaction occurred at our Brighton and Pages 66kV zone substations. Both these substations have since been decommissioned and a replacement substation built (Rawhiti) at a site that did not suffer liquefaction. No liquefaction damage occurred at any of our other zone substations.

Orion sites – Relative liquefaction potential and related damage

Zone substation	Liquefaction susceptibility			Potential for foundation failure	Potential for settlement induced damage
	150 year	450 year	1000 year		
Armagh	Medium	Medium	Medium	Unlikely	Unlikely
Dallington	Low	Medium	Medium	Unlikely	Unlikely
Heathcote	Medium	Medium	Medium/High	Unlikely	Possible
Lancaster	Medium/High	Medium/High	Medium/High	Possible	Likely
Milton	Medium	Medium	Medium/High	Possible	Unlikely
Portman	Medium/High	Medium/High	Medium/High	Unlikely	Unlikely

Substation seismic risk evaluation

We engaged consultants to evaluate substation seismic risk in 1995. A sample of 30 network substations was chosen (by the consultants) from a possible 528 substations to determine structural ability to withstand a moderate-to-severe earthquake. A seismic risk assessment report was prepared. This report showed that significant improvement in seismic performance could be achieved by internally strengthening the substations. A generic strengthening system was developed for a typical pre-1965 substation and we have now strengthened these. All network substations were graded on their importance in the network and we used this grading to prioritise the strengthening work. Our strengthening work on the substation buildings was substantially completed in 2008. During the 2010/2011 earthquakes minor superficial damage occurred, however no catastrophic failures (as seen in similarly constructed buildings) occurred.

Kiosk substations are likely to satisfactorily survive a moderate earthquake because the transformers are connected to flexible cables and can’t move far because of the kiosk housing. Most transformers have metal cable boxes over the high voltage bushings that should protect them from impact damage. A severe earthquake may cause more substantial damage; several kiosks sank or developed a lean due to liquefaction in the 2010/2011 earthquakes.

We expect most cables to cope well in an earthquake, although damage can be expected where cables are stretched due to ground movement. Damage to the overhead reticulation system should be easily repaired.

Flooding

In general our distribution network is not exposed to any great flooding risk. Flooding in excess of 800mm above foundation level would be required before catastrophic failure of most high voltage equipment would occur. Events such as the August 1992 storm, its associated snow melt and high spring tides have already shown the network is quite robust, with only localised flooding around substations close to the Heathcote and Avon rivers. It would be possible, where localised flooding deeper than 800mm occurs, to electrically isolate substations as needed before electrical equipment is significantly damaged.

Snowfall

The significant snow storm in June 2006 disrupted power supplies to some consumers on our network for up to six days. The storm was generally considered a 1-in-20 year event with localised areas considered a 1-in-50 year event. Approximately 60% of individual outages were related to trees affecting our overhead line. After we restored all power we engaged an independent consultancy to review our line design and construction practices. The review also looked at our efforts to restore power and suggested enhancements we could make to reduce the effects of further storms. The review showed that our current standards were adequate however some weaknesses were determined in the existing network. As a result approximately 150 sections of line were identified with more than 10 poles in a row without a strong point. We have programmed to install additional stays on these line sections over the next five years.

Wind

Wind damage is considered a high risk to our overhead line network. The most devastating winds in Canterbury have been from the northwest. History has shown that lines crossing this wind direction suffer more damage than others. Northwest windstorms have caused major damage in our rural area; however the city urban area is less affected. Trees falling and flying debris cause most damage and repairs usually cannot be made until the wind subsides to a safe level.

Tsunami

In light of recent world events we are reviewing our risk in this area. New information available from the emergency management group suggests a number of scenarios will determine the effect a tsunami will have on our network.

Network performance - asset failure

We analyse our exposure to asset failure by assessing individual key assets based on known past performance. Asset life for electrical distribution equipment is very difficult to predict because data on actual life expectancy is limited for most assets. In the absence of hard information we make judgments based on perceived trends and our experience of what happens in practice.

Modern testing technology such as partial discharge testing has minimised the risk of asset failure, especially within switchgear. This has helped with end-of-life planning and asset replacement. Further work is underway to establish a history of failure modes for other assets to help minimise risk and establish end-of-life planning.

Administration building

In early to mid 2010 we reviewed our administration building in Manchester St. We found that the building did not meet the requirements of a Level 4 'lifelines' standard. At that time we made a commitment to construct a new purpose built head office building. However, in the meantime, we have experienced the major earthquakes. Initially our administration building performed well in the 4 September and Boxing Day earthquakes in 2010, suffering only minor damage. However, in the 22 February 2011 earthquake the damage was so extensive that we had to evacuate the building immediately. We relocated to our backup control room (hot site) and began restoring power on our network within a couple of hours.

The hot site was a significant component in our ability to restore power to the undamaged portions of the city in a timely manner. While our computer servers in our compromised administration building remained operational we were however exposed to a greater risk of losing the N-1 capability of our network control systems. Emergency propping was used to secure the structure around the damaged server room to minimise the risk of building failure.

A new transportable data centre was purchased from overseas and located in a 'clear' area on our existing site. Our computer servers and associated equipment were migrated from the damaged administration building to the transportable data centre in a controlled manner to minimise the disruption to our operating systems.

We are currently working out of a circa 1930 building on our existing site while we construct a new administration building which will meet the requirements of a Level 4 'lifelines' building. Our new building must meet lifelines - standard strength and security requirements of the 21st century and allow our staff to function as a single complete team during emergencies. We have engaged Opus International to review our building design in line with our business continuity requirements (level 4). Opus recommended the addition of active links in the building structure. These links act as "seismic fuses" and in the event of a very significant earthquake (return period of 1 in 2500 years) will need to be inspected and possibly replaced. Opus also recommended the inclusion of ceiling access panels and roof hatches to ensure that we can easily access the active links.

We also reviewed the environmental risks associated with the new site. The risks assessed included seismic events, widespread flooding related to the Waimakariri River, localised weather events (rain, wind and snow), tsunami and land movement (slips and subsidence). In addition we looked at the likelihood and consequences of fire within the building.

We concluded that the new (Wairakei Road) site was appropriate for our requirements and that the IL4 building standard dealt with many of the risks we identified. We also recognised that enhancements to the building design, as noted above, were necessary, including:

- establishing active links with easy access for inspection or replacement (see above)

- raising of the building foundation 300mm above the surrounding ground level and the construction of platforms in the yard to support the Transportable Data Centre, batteries, communications mast and generator to mitigate the risk of localised flooding
- application of the new F60 fire standard, zone smoke detection and zone sprinklers to mitigate the risk of a fire in the building.

We will also manage single site risk through the development of contingency hot-sites at some distance from our main site.

66kV cable network

The most significant risk of catastrophic asset failure was our 66kV oil filled cables. Unsatisfactory joint systems connected the aluminium conductors of each section of cable. Thermal expansion of conductors during load cycling could cause buckling and excessive core movement within joints. We engaged an international consultancy to help quantify the risk across the various cable types and sizes.

We then instigated a joint replacement programme that prioritised the joints most at risk. The joints were replaced as quickly as was practicable, consistent with available resources and the need to avoid undue stress on neighbouring cables during the relatively long outages required. This programme to replace all of the at-risk joints was completed in 2010.

Our 66kV cables to Brighton and Dallington were damaged due to lateral forces and subsequently abandoned after the 2010/2011 earthquakes. The Dallington cable has been replaced by a temporary overhead line. Brighton zone substation has been decommissioned and rebuilt on a more geotechnically stable site at Rawhiti with supply via a temporary 66kV line.

We have also instigated a comprehensive half-life maintenance programme for our major zone substation transformers. This has been coordinated with our 66kV joint replacement programme to manage overall supply security risk.

Ripple system

We use the ripple system to control load and limit maximum demand and therefore reduce the need for network investment. Risk of ripple plant failure, which could result in loss of network peak load control, is addressed through system spares. Our decision to replace the existing 66kV injection system with multiple independent 11kV plants has significantly reduced risk as plants can provide backup to each other.

While we own and control the ripple injection plants, the ripple receivers, which actually control load at consumers' premises, were sold to the retailers in late 1998 when distribution and retailing were split into separate businesses. This introduced significant risk. If retailers choose not to install or maintain ripple receivers we may progressively lose control over system peak load. This would result in an increase of up to 15% in maximum demand and we would need to invest more heavily in our network.

To counter this risk, our contracts with retailers enable us to continue to control network system load using the ripple control system with existing ripple control receivers. We also introduced a mandatory requirement from 1 April 2007 that existing ripple receivers must be maintained and all new connections must have a ripple receiver, or its equivalent, to enable us to control any available suitable controllable load, such as an electric water-heater, at least in an emergency. Our pricing structure also encourages retailers to continue to install and maintain existing ripple control receivers.

Distribution management system (DMS)

Our DMS with its integrated SCADA module is a key tool for monitoring and operating our electricity network assets in real time. Through alarms it notifies of potential or actual equipment failure. The DMS can be used to view the electrical state of devices and is invaluable in diagnosing faults and delivering solutions to network related problems. The DMS aggregates and interprets incoming data which is accessed from throughout our network using software located on an array of servers. Loss of the DMS and SCADA system could significantly reduce our ability to detect, diagnose and respond to important network events.

In addition to warranty and maintenance agreements that provide software and systems support, the system is made fault tolerant through the use of backup hardware and communications routing. Multiple identical servers are configured at independent sites with databases mirrored between them. In the event that any of these servers fail, the DMS will continue to operate. All servers must be lost for the system to fail completely.

Future work will focus on communications lines to remote field devices, which currently have single points of failure to enable them to be routed to both server sites in the future.

9.9.5 Mitigation measures – network performance

Procedures and plans

We mitigate risk on several fronts, starting with plans and procedures to handle events beyond our control, and work practices and systems to prevent events within our control from occurring. In particular we:

- inspect assets and identify risks, using maintenance programmes, before they become a problem, which allows time to engineer measures to minimise or remove the risk of failure
- introduce modern technical monitoring systems to give early warning of imminent failure
- use design standards and technical specifications to maintain a high degree of integrity in the construction and maintenance of our assets
- closely manage contracts and audit construction to enforce these standards and specifications
- regularly train and certify staff and contractors in the correct procedures to access the network in a safe manner that does not compromise either staff or the network
- have operational procedures that enable us to respond promptly to electricity outages caused by a wide range of emergencies, as part of our routine operations. These include plans to address oil spills

- have contingency plans and emergency procedures for disaster training that will assist in the event of a major system disruption. These plans include those presented in the following table:

Contingency plans		
Plan	**Reference**	**Key steps**
Natural event/equipment failure	NW20.40.01	• activating the plan • notification of senior management • priority of restoration (preservation of life) • the roles of personnel associated with the plan • customer communication • preliminary action on notice of a tsunami
Supply of emergency generators	NW20.40.02	• activating the plan • notification of senior management • priority of restoration (preservation of life) • generators owned by Orion • consumer-owned embedded generation • details of generator hire companies
Loss of supply to the CBD, zone substations and GXPs	NW20.40.03	This plan contains site specific information for the Christchurch CBD and each of our zone substations. It provides: • low, medium or high risk grading for each zone substation • details of major plant installed • details of specific problems • some restoration options
Security of supply - participant outage plan	NW20.40.09	This plan was created to comply with the Electricity Authority's (EA's) Security of Supply Outage Plan. The procedures outlined in the plan are in response to major generation shortages and/or significant transmission constraints. Under the regulations, participant outage plans (POP) are required to specify the actions that would be taken to: • reduce electricity consumption when requested by the EA • comply with requirements of the EA's Security of Supply Outage Plan • comply with Electricity Governance (Security of Supply) Regulations 2008 and Electricity Governance (Security of Supply) Amendment Regulations 2009 • supplement the EA's Security of Supply Outage Plan

		Reducing demand by disconnecting supply to customers would be a last resort after all other forms of savings including voluntary savings had been exhausted. Orion will always endeavour to keep supply on to customers
Disconnection of demand	NW20.40.05	The purpose of this plan is to mitigate the effects of manual disconnection and demand shedding at points of connection as required by the EA Rules through: • maintaining an up-to-date process to disconnect demand for points of connection, including the provision to the Transpower System Operator of a feeder priority based on a ‘regional or GXP emergency requiring demand shedding’ • assisting Transpower with their automatic under frequency load shedding by providing a schedule of our preferred locations • assisting Transpower with automatic under voltage load shedding for upper South Island (Zone 3) transmission constraints by providing a schedule of Orion’s preferred locations • Providing blocks of load to Transpower for emergency demand shedding

Engineering measures

We have implemented the mitigation measures outlined below:

- we have engaged an emergency contractor to manage distribution equipment spares and provide adequate response to any event on our network. Emergency equipment is stored in a secure environment and we carry out regular audits of stock availability and security. This process is driven by a risk analysis of the possible failure of specific equipment. The spares held support the contingency plans in place to meet our security standard. We hold complete units of some equipment if it is no longer supported by the manufacturer
- structural checks have been implemented and are ongoing to ensure network installations are structurally sound and have adequate hold-down provisions should an earthquake occur. Those buildings and structures found in need of strengthening are the subject of strengthening programmes
- we have installed oil containment bunds at sites that hold oil in excess of 1500 litres. This limits the possibility of oil entering the environment. These sites are also inspected regularly. More appropriate methods exist other than bunds for sites with oil volumes below 1500 litres
- excessive differential ground settlement during an earthquake could damage our 66kV cables. Bridges have been identified as the locations with the greatest risk of this settlement. We have investigated the bridges and reinforced them or taken alternative measures to reduce our dependency on the affected cables

- installation of a new 11kV ripple system to replace the existing overloaded 66kV plants was completed in 2004
- we are committed to ongoing contracts to inspect, test and maintain key assets, as described in Section 9.20 below.

Avoiding major supply failure

The plans and processes described in the preceding section are designed to manage a wide range of identified risks associated with our day-to-day business of delivering electricity safely and efficiently to all our consumer connections.

There is another class of event – the major-plant outage causing huge economic damage (MOCHED) event – that would cause significant economic losses to our consumer base and the community because of its unexpected occurrence. The cause could be a major storm, earthquake or the failure of a major network asset.

The classic example in New Zealand is the failure in 1998 of the 110kV subtransmission cables that supply the Auckland CBD. In that case, a network with an apparent N-2 security standard sustained a complete failure of four main cables (i.e. N-4 failure), leaving the CBD with severely restricted power supply for many weeks.

To avoid this form of 'cascade plant failure' we need all the above elements of good asset rating and condition knowledge, clear operational and monitoring rules and an inventory of key emergency spares, along with good operational contingency and system security planning.

Our main network plant failure modes which we consider could lead to a MOCHED situation are summarised in the following table.

Major-plant outage causing huge economic damage	
Failure mode	**Explanation**
Major subtransmission 66kV cable failures leading to loss of supply from two or more urban zone substations	In most cases N-2 failures in the urban network can be managed with pre-prepared emergency switching plans. This off-loads the affected major zone substation using our existing interconnected 11kV primary distribution network. In times of very high peak system loading it could be necessary to shed all water-heating load, plus additional load, to manage these events within the remaining available capacity. However, if an event occurs that causes outages to more than two major 66kV subtransmission feeders, the potential of more serious overload and potential plant damage to the remaining 66kV cables increases. A 66kV cable failure has a relatively long repair time (up to one week for oil filled cables). In our network the most likely cause of this type of failure is electrical failure of the joints or terminations of 66kV oil-filled cables due to heat from high power loadings. Because most 66kV oil-filled cables are laid as pairs separated by only 600mm, it is also likely that physical damage to the cables could arise from road excavation work or severe differential settlement of the surrounding ground due to earthquake. Multiple failures of cable terminations at GXPs could also cause outages

	to two or more urban substations. Repair times for this type of failure would be two or three weeks, due to the complexity and resource requirements involved in repairing oil-filled cable plant.
Multiple major transformer failures	The failure of one urban zone substation transformer (typically 20–40MVA capacity) is not necessarily a major problem as all such substations have two transformers with dual rating to cope with this type of contingency. However, if both transformers became unavailable for extended periods (N-2 contingency) then the potential for overloading adjacent substations and possibly losing additional customer load is significantly increased, especially during winter peak load periods. Transformer repair times can be weeks or many months. The main reason for operating with less than two zone substation transformers is to carry out planned maintenance. We have reached the point where half-life maintenance of major transformers is required to ensure that their full expected life can be realised. This process involves removing the transformers from site to a suitable maintenance workshop for three to six months depending on their condition. We could thus be subject to a higher risk of interruption to supply from faults on the remaining 'in-service' transformers during this half-life maintenance period. The most likely causes of a transformer fault are high loadings, lightning strikes or high fault currents resulting in either mechanical or electrical breakdown, causing tap-changer, or winding failure. Mal-operation of cooling equipment or overloading can also contribute to excessive temperature rise and subsequent over temperature protection trip operation. Avoiding cascade failure or multiple tripping of major transformers is therefore dependent on good understanding of their capability and condition, as well as co-ordinating their extended maintenance programmes with other major plant outages. The act of removing transformers from service for extended periods of maintenance requires careful management, as it is in itself a significant risk factor. Earthquake damage could also cause common mode multiple transformer failures on our network and at Transpower grid exit points.
Switchgear	Catastrophic failure of high voltage switchgear units (66, 33 or 11kV) can cause a complete section of busbar to fail, either by associated collateral physical damage from explosions or extensive conductive combustion products shorting out internal busbars. Cascade failures involving multiple busbar sections are rare in our network due to the physical partitioning of switchgear in separate fire rated compartments (e.g. indoor 11kV switchgear), therefore the

consequence of failure is generally lower than that for major cables and transformers.

Earthquake damage to 66kV and 33kV outdoor switchgear and structures is also a potential common mode failure for both Orion and Transpower substations.

Repair time for switchgear failures is generally also a lot less than for major cables and transformers (i.e. 12 – 24 hours) however there is still potential for a MOCHED situation.

Mitigation of major supply failure

Our main mitigation strategies and initiatives to avoid a MOCHED situation from the three main plant failure modes described above are:

- we have replaced all at risk 66kV oil-filled cable joints with newly designed joints that will withstand thermo-mechanical buckling forces. We will continue to inspect the other manufacturer's joints (Dianichi) that are assessed to be low-risk. They will be replaced on a case-by-case basis following inspections of their condition
- in association with the joint renewal programme we are retrofitting cable joints and known hot spots with thermocouple thermometers connected to our SCADA system. This will enable cable temperature operating limits to be closely monitored especially in times of emergency
- careful co-ordination of work plans for cable joint replacement and transformer half-life overhauls to avoid excessive risk and a potential cascade failure due to exceeding plant capacity
- the purchase of two spare transformers so that our zone substations are not left for extended periods with only one in-service transformer while transformer half-life overhauls are carried out
- we cover off general 11kV switchgear failures by deploying system emergency spares, largely from stock
- if multiple 66kV oil-filled cables fail, our plan is to assess the repair times and compare time and costs with the construction of temporary 66kV overhead lines. Such lines would be constructed on public roads and run parallel with the faulted cable sections where feasible. Feasible routes servicing the CBD have been assessed. Standard construction designs would be implemented
- buildings that house a 66kV zone substation transformer have been modified to allow the roof to be removed for bushing type connection to any emergency 66kV lines
- we ensure that our network has sufficient capacity to restore supply for N-2 events on our subtransmission network. This is necessary as our 33 and 66kV oil-filled cables may require up to a week to repair. During that time an undersized (N-1) network is exposed to high loads which increase the chance of further failures. By providing N-2 capacity we reduce the risk of cascade failure during cable repair. In the event that further failure does occur, supply can be restored using the N-2 security assets We are currently working to restore N-2 security of supply to the urban subtransmission network, damaged during the earthquakes

- N-2 contingency plans for switching load away from zone substations are in place and arrangements to maximise the use of existing customer-owned standby diesel generators and obtain additional ones have been identified
- we make significant efforts to understand and access all reasonable and prudent emergency ratings of existing in-service plant
- we hold one major transformer emergency spare for each of our standard ratings and voltages
- our extensive power system modelling software and applications can assist in understanding resultant power flows and avoid excessive loadings of network elements caused by network configuration changes. This capability also assists in mitigating plant failure due to excess loading
- earthquake damage has potential to cause significant damage to multiple major Orion substations and Transpower GXPs. Our risk mitigation to date has targeted network substation building strengthening and diversity of supply through improved interconnection between such substations and grid exit points over time
- we have minimised the risk of major zone substation 11kV switchgear failure through assessing switchgear condition and the importance of each site to network security. On this basis, we have now replaced switchgear at Armagh, Fendalton, Grimseys Winters and Brighton (Brighton switchgear is now at Rawhiti) zone substations.

Insurance

The following mitigation measures are in place:

- our material damage insurance policy insures us against accidental physical loss or damage to buildings, plant, equipment, zone and network substation buildings and contents and is based on assessed replacement values. This policy does not extend to include our overhead lines and underground cables. Earthquake cover is restricted to a maximum claim of $100m for material damage and business interruption with a 10% deductable per site
- our business interruption insurance policy which insures us for a reduction in our electricity network delivery revenues and/or increased costs of working as a consequence of an insured loss to our assets as above is for an indemnity period of 12 months
- we also have a range of other insurance policies including liability insurance
- contractors that work for us are required to arrange appropriate insurance for the work being undertaken, giving cover for:
  - third party liabilities
  - contract works
  - plant and equipment
  - motor vehicle third party.

Further information on our approach to insurance is included at Section 9.23.7 below.

9.10 Asset performance

9.10.1 Performance measurement

The main function of our performance measurement process is to assess and maintain levels of network performance. This allows us to set optimal asset and network management standards to meet consumer and regulatory requirements.

We recently commissioned a new outage management system to operate under our PowerOn SCADA network management system. Consequently our outage recording is now fully automated, using SCADA information and a real-time network model. This process is independently audited on an annual basis.

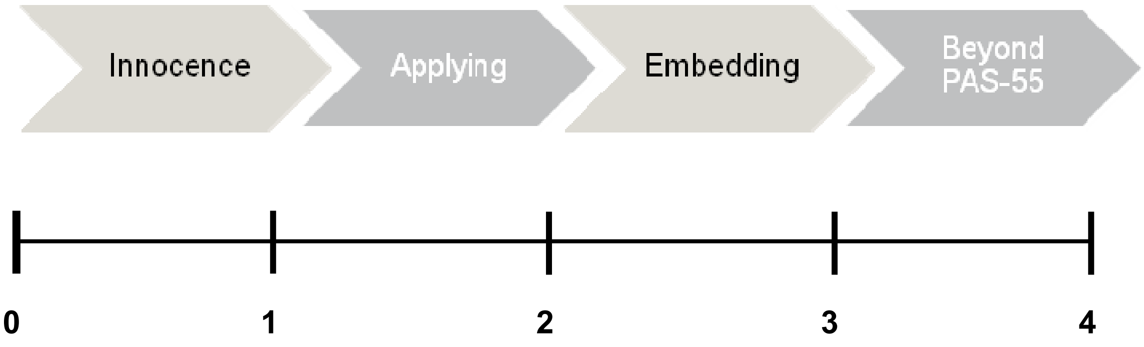
SAIDI and SAIFI figures are monitored and reported on a monthly basis to allow appropriate management of the network. A more detailed formal documented review of network performance is undertaken on an annual basis. This is summarised in our Annual Asset Performance Report.

9.10.2 Asset management maturity

We have recently commissioned a report from EA Technology (EAT) to assess the maturity of our asset management systems and processes. One trigger for this is the recent Commerce Act, Part 4 Information Disclosure Determination (October 2012) which requires us to publish an Asset Management Maturity Assessment Tool (AMMAT) report with our annual AMPs (our first AMMAT report will be published with our 2013 AMP).

EAT's report provides us with a timely assessment of how our asset management processes and systems rate against the PAS-55 international objective standard of good asset management practices. EAT's AMMAT review is available as supporting information.

The PAS-55 approach applies a score to core asset management processes using the following assessment scale:



EAT has scored Orion as fully PAS-55 compliant in nine of eighteen assessment areas. A further seven assessment areas were assessed as at least half way through the embedding phase, the phase immediately prior to achieving full compliance. Only two assessment areas are assessed as being in the initial phases of embedding or applying. We are extremely heartened by this external endorsement of the strength of our asset management process during a time of unprecedented complexity and uncertainty for us.

A summary of EAT's suggested improvement opportunities is below. The identified opportunities represent suggested actions to move Orion's asset management system to PAS-55 compliance in the areas assessed by the AMMAT. EAT notes that not all of its suggested improvements may be warranted from a cost benefit perspective. EAT suggests that we consider implementing only those with potential to provide the greatest improvement to business performance.

AMMAT Assessment		
PAS-55 assessment area	**Score (out of 4)**	**Improvement opportunities**
Asset management policy	2.5 Embedding	Develop a formal asset management policy document and obtain executive endorsement
Asset management strategy	3 PAS-55 compliant	Continue to research and apply new strategies for optimising asset management plans Include strategies defining the disposal phase of the asset management lifecycle Document strategies outside of the AMP and in more detail so as to provide more operational guidance for asset management practitioners within the organisation
Asset management plan(s)	3 PAS-55 compliant	No significant additional requirements identified to achieve PAS-55 compliance
Contingency planning	3.5 Beyond PAS-55	Ensure that experiences and lessons learnt from recent earthquake events are incorporated into future contingency planning processes Share experiences and lessons learnt with other infrastructure providers
Structure, authority and responsibilities	2.75 Embedding	Compliance with the requirements of PAS-55 could however be improved by implementing and documenting a formal process for the analysis and review of short and long term resourcing requirements
Outsourcing of asset management activities	3 PAS-55 compliant	Consider if more formal provisions for incentives/penalties for process or systemic non-conformances can be implemented to allow Orion more influence over this aspect of service provider capability and behaviour
Training, awareness and competence	2.25 Embedding	Develop a formal asset management skills requirements document (skill matrix) defining the required asset management skills as a function of role within the asset management system

		Formally review skill and competency requirements based on the requirements of the long term asset management plan and identify any shortfalls. Consider impacts of changing workforce demographics Develop and implement proactive plans to address any shortfalls in projected skill and competency requirements
Communication, participation and consultation	3 PAS-55 compliant	Develop and document more formalised communication strategies and channels to ensure that relevant information is systematically shared between relevant parties Consider developing communication strategies targeted towards contractor staff to ensure that the context of asset management decisions is fully understood
Asset management System documentation	2.5 Embedding	Develop process flow charts and accompanying documentation defining how core asset management processes operate
Information management	2.75 Embedding	Develop a network data standard including data quality standards for timeliness, accuracy and completeness for key asset management data Implement formal data quality review processes
Risk management	2.5 Embedding	Develop a formal corporate risk management policy that integrates the various risk management sub elements currently in place Fully implement a corporate risk register to record and manage risks on a consistent basis
Legal and other requirements	3 PAS-55 compliant	No significant additional requirements identified to achieve PAS-55 compliance
Lift cycle activities	2.75 Embedding	Document asset management processes in the form of flow charts at sufficiently low level to guide work and information flow for key activities so as to ensure consistent application and enable review and audit
Performance and condition monitoring	3 PAS-55 compliant	While Orion is considered to be using performance and condition measures effectively at present, measurement and feedback is a powerful tool. Improving the collection, analysis and use of condition data should be a subject of continual improvement
Investigation of asset-related failures, incidents and	2.5 Embedding	Document a more formal process and allocate accountability for the investigation and resolution of asset related failures and non conformances

nonconformities		
Audit	3 PAS-55 compliant	Conduct periodic reviews of asset management system compliance, such as this AMMAT self-assessment
Corrective and preventative action	2 Applying	Implement a formal non-conformance process and register so that systemic issues can be formally identified and managed to conclusion. Consider integrating this proposed non conformance register with the corporate risk register for efficiency
Continual improvement	3 PAS-55 compliant	Continue the current culture of innovation Consider documenting Orion's policy and achievements with respect to continual improvement to assist with future PAS-55 audit and reviews

EAT's summarises its core findings as follows:

- the review indicates a number of areas where Orion was not able to demonstrate asset management systems and processes that fully meet the requirements of PAS-55
- while some scores suggest that systems and processes do not meet PAS-55 requirements, it should not be interpreted that Orion's systems and processes necessarily are deficient or not fit for purpose
- on the contrary, Orion's performance and results in the face of trying circumstances provide evidence of flexible, responsive and adaptive processes that have enabled operations and services to continue with an appropriate balance of short, medium and long term focus
- the relatively small scale of Orion's operations in comparison with international asset management businesses for which the standard was initially developed may mean that not all requirements are necessary or the costs is justified to meet PAS-55 standards
- the primary reason for the lower scores is that the PAS-55 assessment criteria requires that asset management systems and processes be formally documented as a means of ensuring consistency and to enable effective audit
- this implies systems and processes for asset management akin to ISO9001 quality systems. In order to achieve a fully compliant score it is in most cases necessary to provide documentary evidence showing the required processes and how they are being complied with
- Orion's asset management operation functions so well at present is likely due to strong but informal communication processes coupled with talented and committed staff
- while more fully documenting processes and requirements is not a substitute for quality staff and organisational culture, it can serve to provide support and consistency in the event that unforeseen circumstances result in substantial changes to personnel or culture.

We are currently considering EAT's draft recommendations. Some actions have already been initiated which are consistent with the suggested improvements. For example, we have improved our documentation by developing a formal asset management policy document (included as Appendix 24). However, we are mindful of the costs associated with some of the potential improvements. Consistent with EA's recommendations we acknowledge that there may be insufficient justification to fully achieve PAS-55 compliance in all areas, particularly where the incremental costs outweigh the potential benefits.

At this time our efforts are primarily focussed on our network recovery activities and restoring our network resilience and quality of supply to consumers. It is possible that some of these recommendations will assist us to do this in a more efficient manner. We will focus on those opportunities as a matter of priority.

9.11 Establishing capex and opex plans

9.11.1 The expenditure objective

IM 5.2.1 (d)

One of the criteria that will be used to assess our CPP proposal is whether our proposed capex and opex meet the expenditure objective. This is defined in clause 1.1.2 of the IMs as:

> *The* ***expenditure objective*** *means the objective that capital expenditure and operating expenditure reflect the efficient costs that a prudent non-exempt EDB would require to -*
>
> *(c) meet or manage the expected demand for electricity distribution services, at appropriate service standards, during the CPP regulatory period and over the longer term; and*
> *(d) comply with applicable regulatory obligations associated with those services.*

In Sections 9.6 and 9.8 we have set out our views on expected demand and service standards. These are incorporated into our capex and opex projects and programmes, as demonstrated in Sections 9.13 to 9.17 and 9.19 to 9.23 below. We have also addressed our regulatory obligations in these sections of this proposal.

In the following paragraphs we specifically address the requirement to demonstrate 'efficient costs' and 'prudency'.

9.11.2 Procurement

A description of our procurement approach is set out in our Procurement Policy (OR00.00.19). Our strategic approach is to:

- procure only when it is in the best interests of Orion to do so
- procure goods and services which are fit for purpose after taking into account whether Orion's objectives can be better achieved in another manner, or deferred to a later time
- obtain best value for money over whole-of-life, including taking into account costs, benefits and risks of procurement as well as ongoing maintenance and other committed or potential costs to Orion which are a consequence of the procurement

- effectively mitigate and/or manage potential liability and other risks created via procurement
- manage our procurement with competent employees and expert advisors, and appropriate policies and procedures
- encourage open, effective and sustainable competition between eligible suppliers
- keep adequate records of our procurement, policies, procedures and decisions that facilitate audit and normal processes of accountability
- comply with all applicable legal and contractual obligations
- effectively manage all intellectual property rights and obligations created via procurement
- effectively mitigate and/or manage any potential conflicts of interest in an open and acceptable manner
- comply with any confidentiality obligations arising from the procurement process
- have fair and transparent procurement processes that are free from fraud and impropriety
- have procurement policies and processes that are sustainable from economic, social and environmental perspectives, as outlined in Orion's environmental sustainability policy OR00.00.03
- consistently innovate and improve on our procurement activities.

Outsourcing

We operate a contracting outsource model for much of the actual maintenance and capex on our network. The planning and operation of our network is performed in-house. We also use consultants and other external experts, such as lawyers, to assist us. These experts provide specialist expertise and independent input in areas where we would not expect to retain the expertise in-house, or where an external view is sought.

Many EDBs provide most of their requirements 'in-house', whereas others use related or third-party service providers for most of their needs. We sit towards the outsource end of the continuum, and have done so since the mid 1990s. We plan and then competitively tender our capital and maintenance works. We believe our approach is the appropriate model for our market, which assists us to achieve cost minimisation, encourage learning and innovation and achieve economies of scope and scale. Even though our network is only the third largest (by connections) in the country, our work programme is insufficient to sustain a large pool of specialised contractors in our region. This is partly influenced also by our location away from the other main centres.

It is in our consumers' long term interests for us to maintain an active market for the provision of electrical maintenance and construction in the Canterbury region.

Tendering approach

Our experience has been that operating a ‘full’ contracting market, seeking multiple tenders for every project, even in a market the size of Canterbury, can be complex and costly. Much of our work is specialised and work on or near live electrical equipment requires us to ensure that all contractors have appropriate skills and experience. This is necessary to ensure their safety and that of the public. It is also critical from a wider network safety, integrity and reliability view point. Further we must ensure that the contractors who work on our network are able to meet our minimum quality standards with respect to cables, lines and the other equipment installed on our network. The long-term costs of poor workmanship or equipment quality are significant as this will compromise the ability of the network meet our required service levels and for assets to perform for their full expected lives.

Given the relatively small size of the market and the specialised services involved, we believe that it is unsustainable to have more than two major contractors in each of our main work categories (cables, overhead lines and substations respectively). This is due to the need for us to provide specialised training and safety systems to all contractors and the amount of work available in each area. While we use a wide range of contractors for a variety of services, the specialised work is limited to a smaller subset of contractors.

We invite tenders from a limited but sustainable pool of approved competent contractors; those who have met our standards (refer to our authorised contractors’ procedure NW73.10.15). We attempt to maintain multiple authorised contractors for each category of work.

We believe that it is in our consumers’ long term interests to have a sustainable number of competent and safe contractors in the market because it fosters competition and innovation.

Evaluating tenders

Virtually all of our tenders are awarded on a lowest price conforming tender basis. Our clear intention within the bounds of a limited local market is to encourage as much of a sustainable competitive tendering environment as we are able, and to as much as possible mimic a wider competitive market. Accordingly our contract management policy (NW73.00.03) is as follows:

- to achieve the best value for its contracted works Orion intends to get competitive prices for goods and services associated with work on the Network Asset, having due regard to the long term network security and work quality
- all work initiated from the Asset Management division that Orion is liable to pay for, with a value in excess of $5,000, should only be performed after obtaining at least two prices
- all work with a value in excess of $20,000 is to be performed as a separate tendered contract
- the lowest overall price is to be the accepted price if the contractor conforms to the lowest price conforming criteria. Otherwise the remaining lowest price may be accepted provided it conforms to the lowest price conforming criteria.

The following exceptions are noted in our policy:

- emergency works and major emergency works may be subject to a negotiated arrangement between the parties including a fixed payment to secure adequate specialist resource
- emergency spares and stock storage (subject to a negotiated agreement)
- SCADA and ripple works (a specialist service)
- metering (a specialist service).

These exceptions reflect the need for particular specialist contractors for metering and SCADA equipment. It is not practicable to assign the responsibility for emergency spares to more than one party. Finally, our urban and rural emergency works contracts are each assigned to a different contractor. Each contractor has primary responsibility for responding to unplanned events within their own area of the network, although they may assist each other during major events. They also call on other contractors within the region, and other distributors (our mutual aid partners) to assist during periods of extremely intense emergency works. Further information about our emergency works contracts is set out below in Section 9.19.

Connetics

We have a wholly-owned subsidiary company, Connetics which along with unrelated contractors tenders for our works. Connetics also tenders for and undertakes works for other parties.

We established Connetics as a stand-alone subsidiary company in 1996 for a number of reasons including the significant cultural differences between an asset management company (Orion) and a field contractor (Connetics). We wanted Connetics to focus on genuine competitive pricing and innovation without the ‘guarantee’ of work from our network. We wanted them to learn new ways of undertaking tasks initiated through competitive pressure; and we wanted Connetics to be able to work for other customers on a truly competitive basis, ie: free from allegations of support from Orion.

In order to manage Connetics on a truly arms-length basis, our practice is that Orion senior management is limited to governance roles with Connetics, and Orion managers are not involved with the day to day management or operations of that business, including the tendering processes. Connetics has its own board of directors, its own CEO and senior management team and its own financial management information systems.

Further information regarding Connetics’ involvement in our capex and opex projects and programmes is set out below in Section 9.25.

Cost efficiency

We believe that our outsourced field work model facilitates competition in our local contracting market and enables Orion to acquire the most efficient prices for its works programme commensurate with the quality of service, skill levels and expertise we require for our network.

In 2010 PricewaterhouseCoopers (PwC) and Sinclair Knight Merz (SKM) on behalf of the Electricity Networks Association (ENA) collected asset construction cost evidence for standard electricity distribution assets from 16 EDBs including Orion. Together these EDBs supplied 85% of the total number of connected customers across the entire electricity distribution sector. A summary of the method used by PwC/SKM is set out in their report ‘Report to the Electricity Networks Association, Revised ODV Handbook, 9 August 2010’. A summary of Orion’s 2010 network construction costs compared to the EDB average is included in Appendix 27.

These comparisons demonstrate that our costs are lower than the EDB average for the core components of our network - most notably: sub transmission lines and cables, zone substations, distribution cables, distribution switchgear and transformers, LV cables and customer connections. Areas where our costs exceeded the average were ground mounted substation kiosks and some LV lines. We know our substation kiosks are more substantial than most EDBs because of the (now proven) seismic resilience we have built into them, which performed so well during the earthquakes. Our LV lines data has been reviewed and corrected for errors pertaining to pole costs. The corrected data (shown in Appendix 27) aligns well with the industry benchmarks.

In addition, in Appendix 28 we include benchmarks for our corporate and network support activities, measured against all New Zealand EDBs and a peer group of EDBs with networks with similar characteristics to ours. These benchmarks show that the costs of our support activities (on a per connection basis) are considerably lower than the industry average, and below the media of our peer group in 2010 and 2011. 2012 data was not available in time for this proposal.

Accordingly we are confident that our capex and opex programme is consistent with the cost efficiency element of the expenditure objective. More information about our costing approaches for each capex and opex category is set out in Sections 9.13 – 9.17 and 9.19 – 9.23 of this proposal.

In addition, we have considered the likely movement in our input costs over the CPP regulatory period. We have made assumptions about how the costs of our core material and labour inputs are likely to change over the next period. This is described in Section 9.26 below.

One particular feature is the local pressures on construction resources due to the Christchurch rebuild. We are starting to see this come through in our tenders, particularly in respect of civil contracting. We note that Statistics NZ has recently started to monitor construction costs in Canterbury for this reason; however their data time series is currently limited. We have sought external advice on what we may expect in the market over the remainder of the CPP period in this respect. There is considerable uncertainty; however this CPP process requires us to make appropriate estimates.

9.11.3 Project and programme deliverability

Schedule D of the IMs requires us to make explicit in our CPP proposal how we intend to deliver our proposed capex and opex plan. In this respect:

> *deliverability means the extent to which the activities to which the capex forecast and opex forecast relate are likely to be undertaken by the EDB during the next period by reference to the EDB's ability to-*
>
> *(a) source and secure physical resources (such as appropriately skilled personnel and materials) and planning consents from external authorities; and*
>
> *(b) prioritise, manage and undertake the work involved, including the ability to implement any planned step change from historical levels of investment and workload*

Our procurement approach outlined above demonstrates how we use a range of contracting resources to deliver our works plan. Our ability to respond so quickly to the unforeseen demands resulting from the earthquakes and re-prioritise our projects and programmes accordingly demonstrates the flexibility that we have available to us in our market. Notwithstanding the resources available, we apply project prioritisation assessments when scheduling our planned works. This process is set out in our Project Prioritisation and Deliverability Process Policy (NW70.60.14).

We are confident we can deliver the capex and opex programme we have included in this proposal. Our use of a number of contractors for field work is a core component of this deliverability objective. We have increased and are planning to further increase our office based resources to provide the necessary planning, operations and contract management support for these projects. This is described in Section 9.22 below.

Prioritisation of projects is complex, because a number of factors are considered. These comprise:

- co-ordination with external agencies such as NZTA and local authorities. This is now more complex post earthquake as we must also consider the needs of CERA and SCIRT
- meeting consumer requirements
- managing contractor resources
- co-ordination with Transpower
- integration of our asset replacement programme with major works
- integration of our asset maintenance programme with major works.

When making judgements about these factors we consider urgency for major projects, seasonal timing to minimise disruption (peak demands occur in winter in our urban network and summer in our rural network) and the most efficient sequencing of projects. Our specific project deliverability considerations for each type of capex and opex are described throughout Sections 9.13 to 9.17 and 9.19 to 9.23.

Contingencies

There are no contingencies included in our capex forecast. Thus we have no allowances for new or unforeseen projects or new obligations which may be placed on us during the CPP regulatory period. We plan to manage any unforeseen requirements by re-prioritising our work programme and substituting projects where possible.

We have included a contingency allowance in our network opex. An annual maintenance contingency budget is included to provision for uncertainties that impact maintenance (predominantly scheduled maintenance, but potentially also non-scheduled and emergency) expenditure. This is described more fully in Section 9.20 below.

We use a contingency of $1.5 million per year, which applies after year one of our planning period, as it allows us to manage any unforeseen cost changes in future years. This amount was set by the Infrastructure group based on analysis of a 10 year period of budgets versus actual expenditure. Events such as the earthquakes in 2010 and 2011 are rare and unforeseen events, the contingency budget is not for these costs.

In addition, in our corporate opex we have a special projects budget. This is an annual provision to accommodate responses to specific management issues which may arise. For example this budget has been used to fund the preparation of our CPP proposal this year. In FY11 and FY12 it was directed to the abnormal costs we incurred in responding to the earthquakes.

9.11.4 Review and governance

Our expenditure plans are subject to management and board review. The Orion board is involved with various aspects of the AMP and it is updated at regular intervals on it. In particular the board questions key aspects of the proposed AMP with management during its development and at the time the full AMP is presented to the board. This year, the review of the expenditure forecasts has been completed earlier than usual in order to complete the CPP proposal.

By way of illustration, in February 2012 the board received board reports, analysis and presentations from network management on the following topics:

- safety
- complaints
- progress against YTD budget and full year outturn forecast
- earthquake recovery
- progress with major projects
- Transpower issues
- progress against Kestrel recommendations
- growth in customer connections
- GFN issues
- spur asset purchase project update and recommendation to approve delegated authority to purchase
- network architecture review update
- Upper South Island (USI) load management

- Fonterra new plant upgrade
- diesel generation at QEII
- location of new head office.

Network and corporate strategy is also presented to and discussed with the board at regular intervals. For example, during calendar 2012 the following (non standard) papers and presentations were made to (and specific approvals sought from) the board:

- Papanui spur asset purchase
- final (third) board review of 2012 AMP forecasts and the SOI financial forecasts and targets
- delegated authority to offer to buy land at Wairakei Road for new head office
- head office insurance settlement and demolition recommendations
- formal approval to buy Wairakei Road site
- delegated authority to accept head office insurance settlement and engage CERA to demolish
- EAT CBRM project update
- PowerOn project update
- 66kV network architecture and engineering
- delegated authority to commence purchase of a first lot of 66kV cable for the north east Christchurch project
- Wairakei Road update
- estimated financial impacts (opex and capex) of the 66kV decisions
- delegated authority to build at Wairakei Road and make an offer for a small parcel of land next door
- delegated authority to proceed to prepare a full CPP application
- environmental risks with Wairakei Road
- insurance renewals
- proposed CPP quality standards
- drafts of CPP documents
- early overview of next year's AMP forecasts (consistent with CPP forecasts)
- approve new delivery service agreement with new retailer on the network
- Audit NZ engagement, proposed consultation plan, correspondence with Commerce Commission regarding the CPP
- increased delegated authority for McFaddens to Dallington cable project and to form contract with SCIRT to install cable
- Kestrel response update
- independent engineer's report re CPP
- full draft AMP
- approve delivery price changes for 1 April 2013 and pricing strategy statement.

The corporate management review of our forecast expenditure usually occurs in December or January. However, we have had to prepare our forecasts earlier for the CPP, and we created a steering group comprising the CEO and Commercial, Corporate Services and Infrastructure GMs to provide internal review of the forecasts (and other key CPP decisions) as they were prepared during 2012.

Accordingly all key corporate managers and the full board have reviewed our CPP forecasts and our draft AMP.

Controls

Our key controls are:

- a clearly articulated, approved AMP
- robust delegated authorities (for example all creditor invoices require two authorising signatures)
- robust contractor engagement and contract management
- quality staff
- collegiate and learning culture.

9.12 Capex forecast

IM D7

Our capex forecasts comprise:

- major project capex
- replacement capex
- reinforcement capex
- customer connection and extensions capex
- underground conversion capex
- spur asset acquisitions
- non system asset capex.

Each of these is addressed below. For the purpose of our discussion, the spur asset acquisitions have been included with the major project capex category, because they have similar aims and objectives.

Schedule D of the CPP IMs include specific information requirements for each category of capex. As we are using our own capex categories, which are similar to, but not exactly the same as those included in Schedule D (for the reasons we described earlier in Section 8.5.3), we have addressed the information requirements as follows:

Meeting Schedule D requirements for capex			
Schedule D reference	**Targeted requirements**	**CPP Proposal Section 9 reference**	**Component of Orion's capex plan**
D7	Minimum requirements for all capex categories	9.13 – 9.17	Addressed in each section (by capex category)
D8	System growth capex	9.13	Major project capex, including spur asset acquisitions
D9	Asset replacement and renewal capex	9.15	Replacement capex
D10	Reliability, safety and environment capex	9.14	Reinforcement capex
D11	Non-system fixed asset capex	9.17	Non-system fixed asset capex

We note that Schedule D does not include specific information requirements for connection or conversion (relocation) capex categories. We have included our explanations for these categories of capex in Section 9.16 below.

A more detailed compliance summary is set out above in Section 9.2.1. We have set out the remainder of the discussion about our capex forecasts in a format which is consistent with the information requirements of Schedule D.

9.13 Major project capex

IM D8

9.13.1 Aims and objectives

The aims and objectives of our major capex projects are predominantly associated with network security, resilience and consumer demand. Before spending capital on our network, we consider a number of options including those available in demand side management and distributed generation. These are discussed further below.

The amount we spend on our network is influenced by existing and forecast consumer demand for electricity and the number of new consumer connections to our network. Other significant demands on capital include:

- meeting safety and environmental compliance requirements
- meeting and maintaining our security of supply standard
- meeting our reliability targets.

9.13.2 The impact of the earthquakes

The earthquakes caused significant damage to our network. We are proud of our pre-earthquake network architecture and engineering strategies to minimise the impact of such events and we are pleased with our operational response during the response and recovery phases. These have been described fully in earlier sections of this CPP proposal, particularly Sections 3 and 6. There is much to be learnt from experiencing an event of this scale and this, coupled with permanent network damage is resulting in inevitable changes to our pre earthquake network development plans.

We are actively gathering new information about the impacts of the earthquakes on our present and future communities. In particular the earthquakes have prompted the need to review:

- the architecture of our network
- our network security of supply standard
- some of our design standards
- our load forecasts
- the appropriateness of more embedded mobile and fixed standby generation.

While these reviews are ongoing, our capex forecast incorporates our most up to date thinking on each of these. These are explained further below, with the exception of our current load forecasts which are set out above at Section 9.8.

9.13.3 Key features

Our major capex programme is made up of the following individual projects.

Capex – Major Projects

Reference	Name	Nominal value over next period ($m)	Identified project
CPP1	Urban Major Projects - North	66.0	Yes
CPP2	Urban Major Projects - Dallington	20.2	Yes
CPP3	Urban Major Projects - West	7.4	
CPP4	Urban Major Projects -Southeast	10.7	
CPP5	Urban Major Projects - South	0.3	
CPP6	Urban Major Projects - CBD	0.5	
CPP7	Rural Major Projects - Rolleston	15.0	Yes
CPP8	Rural Major Projects - Hororata/Creyke 66kV	7.0	

CPP9	Rural Major Projects - Central Plains	6.0	
CPP10	Rural Major Projects - Springston	1.4	
CPP11	Rural Major Projects - Norwood	7.6	
CPP12	Rural Major Projects - Power Factor	0.9	
CPP13	Rural Major Projects - Annat	0.5	
CPP14	Rural Major Projects - Banks Peninsula	1.3	
CPP15	Rural Major Projects - Southbridge	5.3	
CPP16	Rural Major Projects - Dunsandel	2.7	
CPP17	Rural Major Projects - Porters Heights	4.8	
CPP18	Rural Major Projects - Kimberley	2.8	
CPP19	Rural Major Projects - Alpine	0.3	
CPP20	Rural Major Projects - GFN	2.1	
CPP54	Spur asset purchases	34.3	Yes

The key drivers for our urban projects are restoring network resiliency, and accommodating the post earthquake relocation and rebuild. The key drivers for our rural projects are meeting growth and maintaining appropriate quality of supply. The acquisition of Transpower spur assets is a core part of our urban sub transmission development plan.

9.13.4 Deliverability and prioritisation

We have a successful history in managing a succession of multi-million dollar civil and electrical works which demonstrates a proven institutional ability to predict and manage contractor work streams. We manage our major projects as best we are able to ensure there are no significant peaks or troughs for key contract groups. This process is set out more fully in our Project Prioritisation and Deliverability Process Policy (NW70.60.14).

Major projects are generally discrete and therefore are unlikely to extend beyond the end of the CPP regulatory period. Where they may be part of a broader (and longer term) network development plan, this is discussed in each of the Project Summary documents, where relevant.

9.13.5 Documents, policies and consultants reports

Our documents, policies and reports relevant to our major capex category include our design standards, technical specifications and policies as summarised in NW 70.50.03 – Document Control. In particular the policies and standards described in the following sections of our Document Control Policy are of most relevance to major project capex:

- 9.2 Infrastructure
    - 9.2.1 Management
    - 9.2.3 Design Standards
    - 9.2.4 Technical Specifications
- 9.5 Contracts
    - 9.5.1 Management
- 9.7 Procurement and Stock Management
    - 9.7.2 Equipment Specifications

Their significance to our major project capex is summarised in Appendix 21. We note we have no documented land and easement policies.

9.13.6 Planning standards and key assumptions

The first stage of planning a distribution network is to ensure that existing network loads are monitored and tested against existing network capacity. The capacity test involves checking adequacy during contingencies defined in our security standard and also predefined utilisation thresholds. When network inadequacy is identified, the process of developing solutions begins. Each potential solution is assessed for compliance with our design standards including safety compliance, capacity adequacy, quality, reliability, security of supply and economic benefit. These are directly related to our service targets, as set out in Section 9.6 above.

Security of supply

‘Security of supply’ is the ability of a network to meet the demand for electricity in certain circumstances such as when electrical equipment fails. The more secure an electricity network, the greater its ability to continue to perform or the quicker it can recover from a fault or a series of faults. Security of supply differs from reliability.

‘Reliability’ is a measure of how the network actually performs and is measured by interruption data. Our current security of supply standard is set out in Section 6.2.7 of this proposal.

In addition to our security of supply standard, consumers are given the opportunity at the time of initial connection to discuss their individual security of supply requirements. We also facilitate changes to individual security of supply arrangements for existing consumers.

Network utilisation thresholds

We monitor loads on our major zone substation 11kV feeder cables at half hour intervals. Growth at the 11kV distribution level is largely dependent on individual subdivision development and consumer connection upgrades. Growth in excess of the system average is not uncommon and therefore localised growth rates are applied to each region. Zone substations, sub transmission and distribution feeder cables are subject to four distinct types of load:

- nominal load - the maximum load seen on a given asset when all of the surrounding network is available for service
- N-1 load - the load that a given asset would be subjected to if one piece of the network was removed from service due to a fault or maintenance
- N-2 load - the load that a given asset would be subjected to if two pieces of the network were removed due to a fault or maintenance
- bus fault load - the load that a given asset would be subjected to if a single bus was removed from service due to a fault or maintenance.

As defined in our security standard, the location and quantity of load supplied by a feeder has a bearing on whether all or only some of the four load categories described above should be applied to an asset for analysis. If the nominal load reaches 70% or the N-1, N-2 or bus fault load reaches 90% then a more detailed review of the surrounding network is instigated to determine reinforcement requirements.

Capacity requirements

When a capacity or security gap is identified on the network it is necessary to consider different capacity options as solutions. For example, a constrained 11kV feeder can be relieved by installing an additional 11kV feeder to the area. But if the zone substation supplying the area is near full capacity then it may be more cost effective to bring forward the new zone substation investment and avoid the 11kV feeder expense altogether. We use cost benefit analysis to assist us to make these decisions.

The capacity of a new zone substation and 11kV feeders is generally fixed by the desire to standardise network equipment. The capacity of a zone substation and transformer/s is based mainly on the load density of the area to be supplied and the level of the available sub transmission voltage. The expense of 66kV switchgear and underground 11kV cables, along with the high load densities in urban areas, facilitate large zone substations without the issues of excessive voltage drop and losses associated with equivalently sized rural zone substations. Developing a network based on standardised capacities provides additional benefit when considering future maintenance and repair. Transformers and switchgear are more readily interchangeable and the range of spares required for emergencies can be minimised.

When underground cable capacities are exceeded, it is normally most effective to lay new cables. When overhead line capacities are exceeded, replacement of the current carrying conductor may be feasible. However, the increased weight of a larger conductor may require that the line be rebuilt with different pole spans. In this case it may be preferable to build another line in a different location that addresses several capacity issues.

For new load it is often necessary to extend the network into new areas. As new load is connected it is necessary to reinforce the upper network. Overall a conservative approach is taken. New upper network capacity is installed only once new load growth has or is certain to occur. In the short term, unexpected or accelerated load growth is met by utilising security of supply capacity.

Further detail of our approach to increased capacity can be found in our Network Design Overview Standard (NW70.50.05). The following table provides a summary of our standard network capacities:

Standard network capacities

Location/load density	Sub-trans voltage (kV)	Sub-transmission capacity	Zone sub capacity (MW)	11kV feeder size [(1)] [(2)] (MW)	11kV tie or spur [(1)] (MW)	11/ 400V sub capacity (MW)	400V feeders [(1)] (MW)
Urban high density loads	66	40MW radials 40-160MW for interconnected network	40	7	4	0.2 - 1	Up to 0.3
Urban high density loads	33	23MW radials and interconnected network	23	7	4	0.2 - 1	Up to 0.3
Rural low density loads	66	30MW radials 30-50MW interconnected network	10 - 23	5	2	0.025 - 1	Up to 0.3
Rural low density loads	33	15MW radials and interconnected network	7.5 - 10	5	2	0.025 - 1	Up to 0.3

Notes: 1 Network design requires 11kV and 400V feeders to deliver extra load during contingencies and therefore normal load will be approximately 50-70% of capacity.

2 11kV feeders in the rural area are generally voltage constrained to approximately 3-4MW so the 5MW capacity only applies if a localised high load density area exists

9.13.7 Network gap analysis

Our ‘deterministic’ security standard provides a useful benchmark to identify areas on our network that may not currently receive the same high level of security as the majority of our network.

Economically robust solutions to actual and anticipated network gaps caused by eminent load growth are quickly provided for by our capex projects. Network security is maintained on our 11kV distribution network by ensuring that the design of new connections is consistent with our security standard.

On an annual basis, our network planning group updates contingency plans for all valid subtransmission (220kV, 66kV, 33kV and primary 11kV) contingencies. In some cases the security standard criteria for ‘no interruption’ or ‘restoration time’ of load cannot be economically met.

Network gaps arise because the cost of reinforcing the network to the performance level identified in our security standard would be economically prohibitive. That is, the cost to provide the security standard level of performance would exceed what consumers are prepared to pay for it.

In general, network security gaps fall into one or more of the following categories:

- solution is currently uneconomic and an economic solution is not eminent in the foreseeable future
- solution is currently uneconomic but is expected to become economic as load grows in the area under study
- local solution is uneconomic but network expansion in adjacent areas is expected to provide a security improvement in the future
- solution requires co-ordination with Transpower's asset replacement programme and/or is subject to Transpower/Commerce Commission approval.

The economic analysis for each network gap determines the value of lost load (VOLL) when a defined contingency occurs and then utilises probability theory to determine the annual VOLL. This VOLL is calculated using $6.97 per kW for the initial interruption and $16.26 per kWh thereafter. The EA undertook surveys and a review of VOLL in 2010, 2011 and 2012 to better understand the range of VOLL values for different consumer groups and also to provide a check on inflationary impacts since the previous survey (1992) and review (2006). Although preliminary results are available, the EA is undertaking further surveys (including in Christchurch) to refine the results. The results so far suggest that the VOLL values stated above are a reasonable estimate at this time. When the EA's final results are available, we intend to update our VOLL values accordingly.

Although the VOLL of contingencies can be very high, the low probability of occurrence can often lead to a very low annualised VOLL and therefore render the proposed solution uneconomic. This often results in the timing of the solution being largely dependent on the timing of other network development proposals which are required for load growth or asset replacement.

Because annualised VOLL figures can hide the high VOLL of a particular event it is important to consider the implications of rare but costly HILP events if they were to occur. The Canterbury earthquakes have reinforced the importance of building a resilient network and any economic analysis should be considered alongside the asymmetric nature of the risks involved.

Appendix 29 includes our current view of the network gaps against our security standards. It shows gaps on our network and at each Transpower GXP. The appendix includes current security standard gaps only and identifies our proposed solutions for each.

9.13.8 Network architecture review

Significant progress on our urban network architecture review has been made over the past year. The driver for this review has been the requirement for unprecedented investment by Orion in new and replacement assets over the next 50 years, due to:

- earthquake damaged assets and shortened life as a result of earthquake damage
- changes in load due to post-earthquake reconstruction and relocation
- projected load growth in the western urban regions including our pre-earthquake trends and post earthquake acceleration
- using new technologies to improve delivery service.

Accordingly it has been appropriate to review our network design principles. We have completed our urban sub transmission review and our urban 11kV architecture review. Our reviews have incorporated the following key steps:

- identifying key assumptions about the existing and likely future development of the network
- consideration of our security of supply standard
- development of a range of generic topologies suitable for the sub transmission or distribution architecture, as appropriate
- calculating the economic costs and benefits of different solutions
- applying the findings to Orion's current and future network
- modelling the impact of potential options on construction costs and reliability performance
- evaluating options, drawing conclusions, and making recommendations.

The key conclusions of our sub transmission network architecture review are that future extensions to the Orion sub transmission network be in closed-ring N-1 topologies with plans for sufficient cross-GXP link capacity to provide full support in the loss of either urban 66 kV supply. 11kV tie capacity between adjacent zone substations should allow a substation's complete load to be carried by neighbouring substations. It is concluded that the ring bus design provides superior fault performance and facilitates additional circuits being added in the future. A copy of our sub transmission architecture review is included in Appendix 6.

Our 2007 security standard review recommended the introduction of a radial 11kV architecture design with N-2 sub transmission capability. That is, the 11kV feeder cables shall be configured and have capacity to provide restoration of power for a complete failure (N-2) of a zone substation. The current review builds on that piece of work to include consideration of 11kV losses, capacitance, safety, latest pricing and reliability data, and considers the use of remote control and/or monitoring.

The key recommendations of our urban 11kV architecture review are:

- the current radial architecture continues to be used as the design of urban feeders
- the recommended cable design gives capacity to transfer load between zone substations should one substation be out of service. This supports N-2 security at sub transmission level
- trial new safer 11kV ring main units in 2013 to confirm the as built costs
- use the results of the above trial to inform the cost and benefits of a mid feeder intermediate circuit breaker and/or remote switches and indication.

A copy of our urban 11kV architecture review is included in Appendix 7.

It is our intention to undertake a rural subtransmission and 11kV architecture review in 2013. We fully expect this work to support our current plan to exit 33kV and move to 66kV subtransmission in the rural network, but recognise that some refinement may occur. We do not expect this review to conclude that 33kV is an appropriate rural subtransmission voltage for the quantity and sparseness of load that our rural community requires. The quantity and or size of the support structures and conductors required to achieve a 33kV N-1 (excluding some irrigation loads with contracted N security) subtransmission network will be prohibitive from a practicality and cost (including losses) perspective. We continue to make use of as much of the existing

33kV network and transformers as possible, but at present are continuing with our plan to progressively upgrade to 66kV in the rural network

9.13.9 Subtransmission 66kV underground

As part of our network planning, and as contemplated by our subtransmission network architecture review, we have chosen to deploy 66KV underground cables as part of the network solution for certain major urban projects.

An alternative approach is to deploy overhead lines and the technical and economic prudency of deploying underground cables is the topic of some debate. Overall, while Orion could, hypothetically, seek to undertake overhead installation, it has not done so in the past in urban locations and does not propose to do so. This is because:

- it would be contrary to the local government regulations, including CCC's objectives and policies in the City Plan. We seek to comply with the requirements of the City Plan and this undergrounding objective
- the Council has not revised its undergrounding objectives and policies in light of the earthquakes (in contrast to other aspects of the plan) despite the cost implications nor has it seen a shift in community views on this approach
- the City Plan rules and the Resource Management Act 1991 (RMA) require Orion to obtain resource consent or require a designation for overhead installation, the granting of which is unknown, and in either case seems difficult if not remote in relation to installation of new overhead lines
- we believe it would be against the wishes of the Christchurch city community
- it is appropriate to replace 'like with like' for communities where temporary overhead lines had to be installed to replace underground cables as a result of the earthquakes and it is in line with the commitment the community was provided when 'temporary' overhead lines were installed
- we need to take a balanced risk to the natural hazards we face, as opposed to just focussing on and planning for, earthquakes
- in taking all factors into account, it is a prudent approach and it is the approach taken by other like EDBs.

These reasons are discussed further below.

Local government regulatory requirements

The Christchurch City Plan provides the framework for Orion's decision to deploy new subtransmission assets largely by way of underground cables rather than overhead lines in urban areas. A core feature of the City Plan in relation to utilities is its focus on undergrounding of services by network utility operators.

The City Plan shows a clear Council objective for Christchurch – both before and after the earthquakes – is to reduce the number of overhead lines in the city and thereby enhance the city's visual amenity. This objective is sought to be achieved by rules limiting the installation of new overhead transmission lines as much as possible (except in most rural areas), and policies promoting and facilitating the undergrounding of existing overhead services wherever it is technically practicable to do so.

We have sought clarification from the CCC regarding our approach to determine, in particular, whether they have a different view or approach post the earthquakes. Tony Marryatt, CEO CCC, has advised Rob Jamieson, CEO Orion, by letter that:

> *The City Plan went through significant consultation and hearings process when developed and, to the best of our knowledge, reflects community preferences on the undergrounding of power cables. We are unaware of any significant shift of community views on this matter.*

A copy of this letter is included as Appendix 30.

Resource Management Act

We acknowledge the City Plan does not directly compel Orion to underground new services. Instead it (broadly) categorises underground deployment of transmission services as a “permitted” activity, and installation of overhead transmission lines and support structures as either ‘discretionary’ or ‘non-complying’ activities. These categorisations then have compliance implications under the RMA.

The RMA requires resource consents to be obtained for all ‘discretionary’ and ‘non-complying’ activities. To the extent that overhead installation is ‘non-complying’ in particular, we consider we would face substantial obstacles to obtaining resource consent in light of the overarching City Plan policies and assessment matters. The RMA only allows consent to be given for non-complying activities if the adverse effects on the environment (here, primarily visual amenity) would be minor, or the activity would not be contrary to the objectives or policies of the City Plan. We believe that this is unlikely given:

- the Plan’s policies are significantly against new overhead installation and actively encourage replacement of existing overhead structures with underground alternatives
- the Plan’s policies and related objectives and explanations focus on mitigating or avoiding adverse environmental effects (primarily visual effects) of utilities, and require the most difficult level of consent (for ‘non-complying’ activities) when impacts of utilities are most significant (with visual impacts as a recognised ‘major factor’)
- the Plan itself acknowledges the higher cost of underground reticulation, and nevertheless requires and/or actively encourages undergrounding in most urban areas (only ‘unreasonable’ additional costs must be considered in the consent process). It also requires undergrounding in the rural Port Hills because ‘the landscape is sensitive to structures which are highly visible’.

In order to submit a resource consent application for a non-complying activity, we would have to undertake a substantial assessment of effects due to the nature of the work and the large number of potentially adversely affected parties (that is, those homeowners and businesses that will have the lines run adjacent to, or through, their property, as well as the general public). In our experience, this assessment process would likely take around six months, depending on the availability of technical experts to undertake these assessments.

Once a ‘complete’ (for the purposes of section 88 of the RMA) resource consent application has been accepted by the Council, the Council will almost certainly publicly notify the application to allow for members of the public to lodge a submission. The reason public notification is almost certain is due to the large number of adversely affected parties. Further, we would expect that many of the adversely affected parties would, as a result of the adverse visual and amenity effects of overhead lines, lodge a submission opposing the application and want to be heard at the hearing.

A publicly notified application would go to a hearing before the one or more Commissioners assigned to make a decision on the application. We would provide expert evidence on our application and submitters would have the opportunity to speak to their submission.

If our application is publicly notified, this will significantly extend the timeframes in which the Council makes a decision on the application. The Council’s guidelines on processing applications state that generally a publicly notified application is likely to be processed to a decision in around three to four months, but experience shows the timeframes are likely to be longer. Inevitably, a contentious application such as this would require even more time to be processed and heard. In addition, these time frames do not include:

- the work required for us to prepare the application before lodging
- the time taken to provide any further information, should this be requested by the Council anytime after we submitted the resource consent application
- any appeals which may eventuate out of the decision.

The length of time it would take to resolve any appeals would depend on whether the parties to the appeal could come to a mediated agreement and settle the appeal. If not, the time to prepare for, hear and have a decision issued on an Environment Court appeal would likely be, at a minimum, one year.

Even after the process is complete, we run the significant risk that the decision maker may in fact decline our application for overhead lines on the basis that the City Plan supports the provision of underground lines.

The likely cost of a publicly notified resource consent application, from providing expert assessment to hearing costs, is difficult to estimate but is likely to be in the region of $150,000. If the decision was appealed, the cost of a *de novo* Environment Court hearing could likely be in the vicinity of $500,000.

The time (of up to two years) and cost involved is very substantial given our need to undertake this work to restore resilience in the network. We believe it is critical that we are able to restore our network in a timely way so that our consumers and the wider economy have confidence that the network is stable and functional. A lengthy and probably unsuccessful resource consent process runs directly counter to this imperative.

As an alternative to the resource consent option, Orion could (as a ‘requiring authority’ under the RMA) instead seek to utilise the ‘designation’ process to enable it to undertake overhead reticulation without resource consent. While different decision making thresholds apply in the designations process, the policy objectives and environmental impacts highlighted above remain significant factors and represent potentially significant obstacles to pursuing the designation option. That being the case we do not believe this is a plausible option.

Community preference

We believe there would be an extreme public reaction if we tried to put these cables overhead. Our view is supported by past public reaction. Notably:

- as far back as 1978 the NZED proposed an overhead northern loop similar to what we are proposing. There was an extreme public reaction and this did not proceed
- successive Council's consulted on, and included, broad underground policies in their city plans. The Christchurch City Council has advised us that it has not seen a shift in public sentiment on this post the earthquakes
- there was significant adverse reaction to TelstraClear's roll out of overhead fibre optic cables
- immediately after the earthquakes, and even in that context, there was significant adverse reaction to our roll out of temporary overhead lines in the east of Christchurch, even in the context of an emergency situation the community faced due to the earthquakes. Strong and emotional opposition was voiced at a series of public meeting which we held to inform residents of the need for the temporary overhead lines. This is a strong indicator that the community's views have not changed on their preference for overhead lines post the earthquake. We note that the issue of compensation for 'devaluation of property' was consistently raised, with residents wanting assurances that Orion would compensate them for any negative impacts suffered as a result of the overhead lines. Other comments made included concerns about the 'daily impact' of 'these eyesores'. People also expressed concern about the stability of power poles in their earthquake damaged streets and the potential health impacts and noise nuisance from high voltage overhead reticulation so close to houses in residential streets. Given the fragile mood in the hard hit eastern suburbs, we have not wanted to unsettle residents further by putting a proposal to them that seriously suggests a permanent 66kV overhead solution. From the feedback received to date about overhead lines, we consider the suggestion of an overhead solution would provide a further significant blow to a community that is already under pressure.
- in addition to the above community reaction, we are now seeing developers being proactive with respect to undergrounding. They are actively putting subtransmission underground to meet consumer preference and the market. A Westmoreland subdivision is an example of this.

Like with like

With respect to some of the major subtransmission projects we are replacing 'like with like' as a result of earthquake damage. Communities invest and live in an environment with underground HV power. It is reasonable for those people to expect that we would replace like with like unless something has fundamentally changed. We don't believe it has. Orion can provide a robust power supply with underground HV cables.

In addition, a further factor to note is that these communities have borne the brunt of the earthquake damage. To change our approach and install permanent overhead lines instead of like cables would be traumatic for the community on environmental, aesthetic and economic fronts.

Balanced risk approach to natural hazards

As a result of the earthquakes we have had to consider whether it is sensible to deploy cables given the impact of the earthquake on them. We believe it is important for us to take a balanced risk approach to natural hazards. While earthquakes (and consequences of them such as liquefaction) are foremost in people's minds there is, as we discuss below, a far greater likelihood of our network being impacted by snow and wind storms. Underground cables withstand these sorts of frequent events better than overhead lines. We note that in 'normal' (non earthquake) circumstances, the fault rate of 66kV, 33kV and 11kV lines is three times that of the equivalent underground cable solution.

Balanced risk approach to our network

Christchurch has experienced thousands of earthquakes since September 2010. An extremely small percentage of those resulted in damage to our network.

Two terms are frequently used when talking about the impact of earthquakes. They are magnitude and intensity. The **magnitude** of an earthquake is a measure of its size and relates to the amount of energy released. The **intensity** of an earthquake is measured at a particular site and depends upon:

- magnitude of the earthquake
- depth of the earthquake source
- distance from the epicentre (the point on the earth's surface directly above the source
- ground conditions at the observation site, and between there and the source
- duration of the shaking.

Magnitude is generally measured in terms of the Richter scale. Every time the Richter magnitude increases by one it represents a twenty-sevenfold increase in the size of the earthquake. In other words, a Richter magnitude 7 earthquake releases 27 times more energy than a magnitude 6 earthquake. Intensity is often quoted in terms of the Modified Mercalli (MM) scale which is graded MM I to MM XII. This scale is based on observed effects and is subjective. For instance MM VI shaking is described as:

> *Felt by all; many frightened and run outdoors; some heavy furniture moved; a few instances of fallen plaster or damaged chimneys; damage slight.*

The following table shows the damage impact upon our 11kV cable network for the three major Christchurch earthquakes experienced in 2010 and 2011.

Impact of major 2010 and 2011 earthquakes

Date	Magnitude	Distance from city (km)	Number of 11kV cable faults	Modified Mercalli scale estimate
4 September 2010	7.1	38	30	MM VIII
22 Feb 2011	6.3	6.7	250	MM VIII - IX
13 June 2011	6.4	9.2	130	MM VIII

Our recent experience has shown that the MM scale is a good indicator of cable network damage and that very little network damage occurs at levels of MM VII and below. A key cause of damage to our cables is that our 66kV cables were encased in concrete to help with their thermal rating. This makes them very rigid and prone to damage where ground movement occurs (eg lateral spread). An inspection of cables that failed showed that the cables had generally failed because of excessive tensile or compressive stresses. A method of reducing this risk is to make the backfill less rigid by using flexible backfill options.

Estimates provided by the Canterbury Regional Council (CRC) prior to the recent earthquake series identified that Christchurch would experience a MM VIII earthquake once in the next 450 years.[33]

Further to this, other estimates also confirm a lengthy timeframe before we are due to have another MMVIII earthquake. The more recent the estimate the longer the estimated time before the next MVIII earthquake:

• Smith & Berryman (1983)	160 years
• Elder	120 years
• Smith (1992)	250 years
• Dowrick (1997)	650 years.[34]

Based on this it is fair to assume that an earthquake could have a significantly damaging impact on our cable network only approximately once every 450 years.

Snow storms and wind storms happen much more frequently and because our overhead network is exposed to this, wind and snow damage occurs to our overhead network regularly as set out below.

- on average we budget for a minor storm every two months. The overhead network is normally restored between one and three days
- larger storms such as the 1975 wind storm (about a 1/50 year event) took three weeks to restore power and longer to restore full resilience

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[33] CRC publication E99/1

[34] Risks & Realities, 1997

- the 1992 snow storm (about 1/50 year event) took about one week to restore power and many years to fully recover and restore the overhead network
- the 2006 snow storm (about 1/40 years) took about one week to restore power and four months to restore resilience.

In summary, an overhead network is impacted more frequently by natural events compared to an underground network. Both CERA and the National Infrastructure Plan consider we should take resilience into consideration when developing our network and planning our network recovery. It is true underground cables take longer to repair than overhead lines, however, given the frequency of events like snow and wind storms, compared to earthquakes, the efficiencies gained through ease of repair are offset to a degree by the frequency of outages caused by much higher probability events such as snow and windstorms.

Learning from the earthquakes

In addition, despite the low probability of more significant earthquakes, we have learnt from the earthquakes. We continue to address a number of areas where we have needed to improve security and performance in underground subtransmission to avoid resilience being compromised or repairs needed from earthquake related impacts such as liquefaction or lateral spread. Initiatives being taken in relation to this asset include the following:

- understand the geography and avoiding areas susceptible to lateral spread or liquefaction
- specifying cable support systems and trench backfill to provide adequate but flexible support or reinforcement for cables
- the continued transition to an interconnected/meshed 66kV network with diverse cable routes
- using route diversity for cables.

Other EDBs

Our approach to subtransmission underground cables is not out of step with other high density networks. The table below shows disclosure data for Orion and the two other metropolitan New Zealand high density networks showing percentage underground, by voltage.[35] The circuit length data is not disclosed on a rural/urban basis by voltage.

Underground circuit length as proportion of total circuit length by voltage

EDB	Network level	FY06	FY07	FY08	FY09	FY10	FY11
Wellington Electricity Lines (35.59 ICP/km)	Subtransmission	-	-	-	72.2%	72.2%	72.6%
	Distribution	-	-	-	65.2%	65.3%	65.6%
	LV	-	-	-	58.1%	58.3%	58.5%

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[35] We note the data is not available for rural and urban locations within each network. In addition, Wellington Electricity data is incorporated in the Vector data prior to FY09.

	Total	**-**	**-**	**-**	**61.4%**	**61.6%**	**61.8%**
Vector (29.90 ICP/km)	Subtransmission	54.2%	54.1%	54.7%	52.0%	53.1%	53.3%
	Distribution	48.9%	49.3%	49.6%	46.6%	46.9%	47.4%
	LV	54.3%	54.5%	55.4%	55.0%	55.4%	55.9%
	Total	**52.1%**	**52.3%**	**53.0%**	**51.3%**	**51.8%**	**52.3%**
Orion (17.95 ICP/km)	Subtransmission	16.7%	17.0%	16.9%	16.5%	17.3%	15.0%
	Distribution	39.0%	39.2%	39.8%	40.2%	40.7%	41.5%
	LV	55.9%	53.3%	53.8%	54.2%	54.6%	54.8%
	Total	**44.9%**	**44.2%**	**44.7%**	**45.1%**	**45.6%**	**45.9%**

Following table shows the proportion of subtransmission circuit underground for each network.

Underground subtransmission circuit length as proportion of subtransmission circuit length by voltage

EDB	Voltage	FY06	FY07	FY08	FY09	FY10	FY11
Wellington Electricity Lines (35.59 ICP/km)	33kV				72.2%	72.2%	72.6%
	50/66kV				-	-	-
Vector (29.90 ICP/km)	33kV	52.4%	52.4%	53.0%	49.7%	50.9%	50.8%
	50/66kV	71.6%	71.6%	71.4%	71.4%	71.4%	73.2%
Orion (17.95 ICP/km)	33kV	7.3%	8.1%	8.2%	7.6%	9.1%	9.4%
	50/66kV	34.4%	34.1%	30.8%	30.4%	30.4%	24.2%

From this data we conclude that our approach is consistent with the other metropolitan networks, and indeed discussion with them confirms our understanding that urban subtransmission is placed underground in large cities in New Zealand. These networks have cited consenting and local government plans as important drivers for this response.

Cost

We have heard statements that the cost of undergrounding is five times that of installing overhead lines. That is not our experience and we believe a ratio of 3:1 is more accurate (when comparing construction costs). If the lifecycle cost of underground and overhead systems is taken into account, including the impact of electrical losses, the difference in cost is smaller still.

9.13.10 Non-network solutions

When the network becomes constrained it is not always necessary to relieve that constraint by investing in new zone substations, 11kV feeders and 400V reinforcement. Before implementing network investment solutions, we consider the following alternatives:

- demand side management (DSM)
- distributed generation
- uneconomic connections.

Demand side management

DSM provides an alternative to transmission and distribution network reinforcement. It can be defined as shaping the overall consumer load profile to obtain maximum mutual benefit to the consumer and the network operator.

Since legislation required electricity retailers to be separate from network operators, it has become more difficult to implement a fully integrated DSM strategy. Electricity consumers are generally no longer directly contracted to Orion. Our primary mechanism for achieving better utilisation of the assets is to signal the investment cost implications to electricity retailers in our delivery pricing structure.

We are integrating DSM into development of our network. Some of the gains from DSM are:

- increased utilisation of the network and increased effective investment return
- improved utilisation of Transpower's transmission capacity
- consumers benefit by becoming more efficient in the utilisation of energy and network capacity
- consumer relations improve through less upward pressure on prices.

The following DSM strategies are applied or are being investigated by Orion:

- ripple system – anytime hot water cylinder control
- ripple system – night rate price options to spread load more evenly over the period
- ripple system – major consumer price signalling
- ripple system – interruptible irrigation
- power factor correction rebate
- review of hot water cylinder service levels
- coordinated upper South Island load management.

Our AMP includes information to assist potential DSM providers to determine the approximate funding available from Orion if specific projects are able to be deferred through DSM. The AMP includes a high level assessment of the annual per kW cost of proposed network solutions where DSM could be used to defer the project. If a DSM solution is presented, then further detailed analysis is undertaken to compare options. As multiple projects are sometimes required to resolve network constraints, they are grouped together for this analysis.

Our demand side management policies (NW70.60.10 and NW70.60.11) reflect our development of DSM initiatives. The first policy sets out our framework for considering DSM initiatives. It provides a summary of problems or opportunities where DSM may be able to provide a cost effective solution. The second policy determines the likelihood of DSM making a difference, identifies the most likely initiatives and includes an initial cost-benefit analysis on each of these. The third and ongoing stage will be the detailed business case, planning and implementation of any beneficial DSM initiatives.

Our current view on the application of DSM on our network is summarised in NW70.60.11 as follows:

- in the short/medium term, embedded generation is likely to be needed to complement any other initiatives to achieve sufficient response to defer network investment. Longer term, electric vehicle charging is expected to be a worthy candidate for DSM
- other initiatives are expensive or offer little benefit in the areas needed. They have ongoing risks of not sustaining the response long enough to pay back the investment or an ongoing response with associated lost revenue after the network upgrade has occurred.

Possible new initiatives are summarised in the following table.

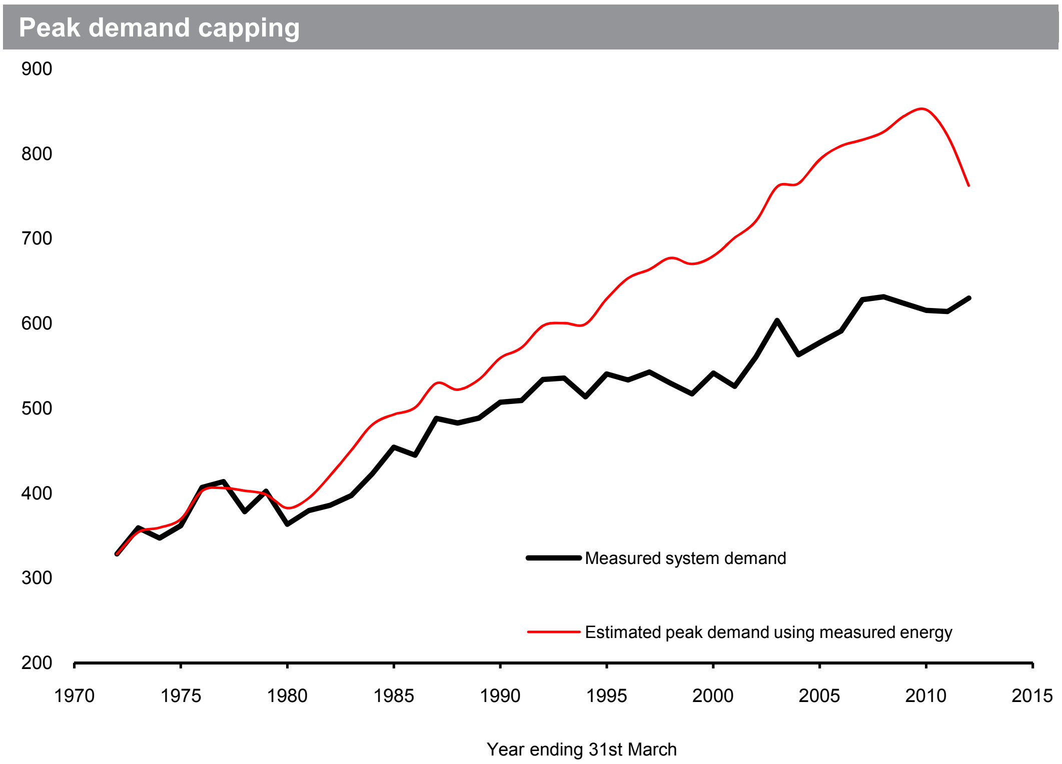
Possible new DSM initiatives

Initiatives	Explanation
New network initiatives	• diesel generation is priced well compared with network investment and can offer sufficient capacity to defer network projects. The uncertainty associated with consents is dealt with upfront and is expected to be achievable in most of the areas listed to benefit from DSM • electric vehicle charging has insufficient quantity to make a difference in the short term. However, we need to be involved in developing a charger standard for NZ • smart meter trial in Orion kiosks - no direct DSM benefit initially, but is a precursor to other smart meter possibilities. May enable deferral of LV network reinforcement through better planning information
Network initiatives to watch	• battery storage is expected to become significantly cheaper as a result of current research and eventually the availability of large quantities of second hand electric vehicle batteries. This makes it a viable alternative if consent for diesel generation is not possible and sufficient space is available • pricing opportunities may arise through regulatory intervention • influencing retailers - household smarts offer small benefits, but may become achievable at minimal cost if and when smart appliances are available
Considered network initiatives	• new interruptible load for major customers is difficult to achieve with current technology other than engaging with those that could, but don't, respond to the Control Period Demand signal. Currently the main benefit would be for additional load curtailment if needed in response to an event

	• new interruptible load for small and medium enterprises is less cost effective than for major customers and can be more difficult to secure due to retailers rebundling our pricing. The maximum achievable quantity, difficulty in locating motivated responders and risk of lost revenue from any response that continues after the network investment is made, means this initiative is difficult to invest in
Initiatives to protect or enhance	• pricing – ensure regulators maintain our ability to price for DSM • protect hot water cylinder load management • solar hot water ripple signalling is a very good value initiative if there are sufficient solar hot water systems to make a difference. It is much easier to obtain this benefit if the signal is available when the solar system is first installed. Therefore the ripple signal benefits from being commissioned before lots of solar water heating systems are installed • system for USI load management as a platform for further possibilities.

Ripple control

Ripple control is one of the most effective tools available for implementing DSM. Ripple enables us to send a myriad of load control and pricing signals to our consumers. Over the last 30 years, our commitment to DSM through hot water cylinder control and peak and night rate price signalling has resulted in a dramatic difference between the growth in peak demand and energy. This is illustrated below.



Since 1980 a gap of 200MW has been achieved between energy based estimated peak demand and actual peak demand. Committed utilisation of our ripple control system is thought to have been the driver for approximately 100-150MW of the 200MW gap between demand and energy. Ripple control has facilitated the implementation of the following DSM strategies:

- hot water cylinder control – 50MW of peak load deferment
- night store heating – 125MW of night load providing an estimated 50MW peak reduction
- price signalling to major consumers – 25MW (includes embedded generation)
- interruptible irrigation load groups (summer only) – 28MW during contingencies.

To ensure that we can continue to achieve these results, three 66kV ripple injection plants have been replaced with multiple 11kV ripple plants. 11kV ripple plants avoid overloading issues caused by an increasing number of capacitors being installed on Transpower's grid and also reduce dependence on any one item of plant.

A current issue is our dependency on ripple control receivers located at consumers' premises. Orion does not own these receivers and therefore has limited ability to control their installation and maintenance. In 2007 we modified our Network Code to make it mandatory to install ripple receivers that respond to an emergency signal. We will continue to work with retailers and meter owners to ensure that the benefits of ripple control continue to be achievable as the implementation of new technology occurs.

Interruptible load groups – irrigation

When an interruption to supply occurs on our network, there is a cost of lost production and the inconvenience to our consumers. Our targets for reliability are based on matching the cost of an interruption to the cost of preventing one. That is, there is a point where investing further in our network is not justified by the cost saving to our consumers from reduced interruption times.

Not all consumers are exposed to the same costs when an interruption occurs. To reduce expenditure on the network and therefore control price, it can be useful to first restore supply to consumers who have a high cost of non supply, and then restore supply to those consumers with a low cost of non supply when the fault is repaired. Following consultation in 2005 with irrigation consumers, we have extended the possible duration of interruptions for irrigators up to 48 hours under extreme conditions. At the time of implementation, the ability to do this prevented the need to install Ardlui zone substation and delayed several other projects. The continued application of interruptible irrigation has avoided and delayed further network investment over the last six years. This has been passed on by way of lower prices than we would otherwise have been able to achieve.

Power factor correction rebate

If a consumer's load has a poor power factor then our network must deliver a higher peak load than is necessary. This may lead to network upgrades. Our Network Code requires all consumer connections to maintain a power factor of at least 0.95. During 2010 we introduced a penalty charge for consumers whose power factor falls short of the 0.95 minimum. In the Christchurch urban area where the predominately underground network is high in capacitance (which helps to improve power factor), the minimum 0.95 power factor requirement has resulted in an overall 0.99 GXP power factor at times of network peak. This is a good outcome and any further benefit from offering financial assistance to correct the power factor in the urban area would be uneconomic.

However, in the rural area, the predominately overhead network is high in inductance (which reduces power factor) and we offer a financial incentive in the form of a ‘power factor correction rebate’ to irrigation consumers with pumping loads greater than 5kW. The rebate provides an incentive for irrigators to correct their power factor beyond 0.95. The charge is set at a level which recognises the avoided network investment cost associated with power factor related network upgrades.

Heat pump efficiency promotion

The ECAN Clean Air initiative in Christchurch has encouraged many consumers to change from solid fuel burners to electric heating. The high efficiency of heat pumps compared to resistive heating methods has lead to strong uptake of heat pumps in Christchurch. The high variability of efficiency and quality of heat pumps on the market has resulted in us taking a strong interest in the promotion of appropriate models.

When EECA released the new energy star label on heat pumps we supported a promotion about ‘how to choose your new heat pump’. It is envisaged that encouraging consumers to purchase high efficiency heat pumps will reduce the increase in peak demand on our network.

Coordinated upper South Island load management

As well as controlling hot water cylinder load to manage peaks on our own network we also control hot water cylinders to manage peaks on Transpower’s upper South Island network. We do this via a specifically designed upper South Island load manager which communicates with Transpower and all of the upper South Island distribution network companies. Through cooperation and the coordination of upper South Island load control we are able to maximise the potential to reduce peaks without excessive use of hot water cylinder control.

We note that the EA has an interest in load management and they are currently investigating incentives for a market based approach to this service. This may compromise our ability to control load for Canterbury and the upper South Island which could result in increased capacity investment requirements for our own network.

Distributed and embedded generation

The purpose of our distribution network is to deliver bulk energy from Transpower’s GXPs to consumers. In certain circumstances it can be more economic for the consumer to provide a source of energy themselves in the form of distributed generation (DG). DG may also reduce the need to extend network capacity.

Our policies (NW72.15.05, NW70.10.09) for DG provide a different treatment for different sizes of distributed generation. In particular our policy for DG above 750kW gives consideration to the following issues:

- coincidence of DG with Transpower interconnection charges
- benefits of avoided or delayed network investment
- security of supply provided by generators as opposed to network solutions
- hours of operation permitted by resource consents
- priority order for calling on peak lopping alternatives, such as hot water control versus DG.

In order for DG to be effective we require a contract to ensure that peak lopping is reliably achieved. This is done through pricing structures that encourage users to control load at peak times. We will continue to encourage DG through appropriate pricing mechanisms. Given the large investment and significant network constraint deferment associated with export generators of more than 750kW, we assess them on a case-by-case basis.

We continue to proactively support the installation of DG by major energy users. An incentive for major consumers to generate electricity is provided through our pricing structure which includes an avoidable control period demand charge. We estimate that approximately 15MW of generation is available on control period demand signalling. The total major customer response is about 20 MW and some of that is load reduction (rather than generation). A further 13MW of standby generation is owned by consumers for their own use during an interruption.

Our peak load forecast assumes that an additional 2MW of peak DG will be installed each year. The earthquakes have led to an increase in enquiries to connect diesel generation and we anticipate a corresponding period of strong growth in the connection of diesel generation. For this to be effective in deferring network capacity, the generation capacity must be reliably available to support the network in the event of an interruption to supply. In general this requires that generation be offered to operate as and when required, which in turn necessitates that fuel is able to be stored.

DG using fuel that cannot be stored does not usually substitute for network capacity unless fuel supplies are stable and reliable. Wind, solar, and run-of-river hydro are three types of generation that provide energy but do not substitute for network capacity. However, with multiple sites and diversity in fuel characteristics, some certainty of availability can be determined through analysis of historic data.

We have resource consents to install a total of 23MW of generation capacity split between sites at Bromley and Belfast. Generation at the Belfast site has the potential to defer investment in a new zone substation at Marshlands and the proposed extensions to our 66kV sub transmission network in the area. These network deferral benefits coupled with the benefits of avoiding transmission charges make investment in diesel generation at Belfast an economic proposal. The earthquakes have resulted in significant damage to our 66kV sub transmission network feeding the Christchurch north eastern suburbs. To provide alternative capacity in the area, we have recently installed two 2MW diesel generators for short term placement at QE2 with the intention of relocating them to Belfast in the medium term.

Justification for installing generation at the Bromley site will require either an energy-firming contract with an electricity market retailer or suitable market arrangements to reward us for relieving transmission constraints between Twizel and Christchurch. Depending on the nature and duration of any contract, this generation may also provide alternative investment options for our distribution network. The introduction of 'scarcity pricing' in the market should encourage industry participants to manage their own risks with respect to energy-firming and transmission constraints and may also provide other contract opportunities for our consented diesel generation sites.

Our potential involvement in large scale generation projects is limited by regulations although this has relaxed slightly in recent times. Our policy for embedded generation is NW70.10.04.

9.13.11 Costing methods

The methodology we have applied in forecasting the costs for our major capital projects is summarised in our Project Budgeting Forecasting Process Document (NW70.60.13).

Our project forecasts are developed using a cost estimating database. The database includes costs for nearly 300 items, as well as grouped costs for common assemblies. For each project, the unit costs are selected to build a project costing estimate. The database provides a consistent way of budgeting for each project using standard unit costs.

Each year before our planning process starts we update our unit costs in the following ways:

- actual projects are reviewed from the past year. Labour costs and material rates are extracted by the Network Asset Manager and fed into the database by the planning team
- quotes are obtained for items to be purchased for the next year. For example, cable prices are updated each year from updated pricing schedules from cable suppliers
- estimated movements in labour rates are entered, using actual contract rates where known as a source
- estimated price changes are made on items purchased less frequently. These are based on assumptions about exchange rate fluctuations and commodity price movements. When commencing projects which contain these items, we seek quotes from suppliers the year before the project is to be implemented.

Our budgeting document (NW70.60.13) contains a full list of the unit costs used to derive the major project capex forecasts. These are expressed in FY13 terms. Our cost escalation method is outlined below in Section 9.26.

This process ensures we base our project estimates on current costs which reflect market prices. As our capex projects are competitively tendered, and selected on the basis of the lowest conforming tender price we are confident that using actual contract prices provides us with a robust method for determining our expenditure forecast. The construction cost benchmarks presented in Appendix 27 support this conclusion.

Our major task in deriving capex estimates therefore is to estimate the quantity of each unit to be included. This is necessarily quite granular. However, this has assisted us to meet the CPP information requirements because we have been able to easily allocate our capex projects across asset types, which are required for escalation and depreciation purposes.

66kV subtransmission cable costs

Recent developments in relation to our planned 66kV cable projects in urban Christchurch have caused us to reconsider our standard project costing method for installation of these cables. These impact CPP project 1 (urban north), project 2 (urban Dallington), and project 8 (rural Hororata / Creyke).

During the period from 1969 to 1981, we installed a number of 66kV underground circuits in the CBD and surrounding Christchurch suburbs. The need to install new 66kV underground circuits since then has been very sporadic as summarised below.

Orion 66kV cable installation

Circuit	Install year	Length (m)
Barnett Park	1987	120
Bromley to Lancaster	2000	4,884
Armagh T1/T2	2001	75
Lancaster to Armagh	2002	2,363
Middleton GXP to Middleton T1	2008	375
Middleton GXP to Middleton T2	2008	365

Although the Middleton projects provide a useful reference for the pricing of the cable, the circuit length was too small to provide a useful reference for the civil works component of the longer circuits now planned post earthquake. We have used cable pricing estimates provided by Prysmian (since 2008) to help us compare network options at the planning stage.

Our traditional pre earthquake approach to 66kV underground cable projects is to tender all aspects of the work including cable supply and installation. These can be structured as either a ‘turn-key’ price or to split the project so that cable supply (including jointing) is separate from the installation component, including civil works and cable laying.

The earthquake has resulted in major damage to the networks of other infrastructure providers and the public roads in general. There is a public expectation that major projects in the road will be coordinated to minimise rework and disruption. The CCC as the road controlling authority is responsible for creating and managing the rules for use and access to the road. To better manage and coordinate the large scale of works following the earthquake, CCC has entered into an alliance contract arrangement (SCIRT) with a number of contractors, NZTA and CERA to coordinate significant road and infrastructure contracts.

The requirement to remove the temporary 66kV overhead lines to Dallington and Rawhiti by March 2014 places significant pressure on Orion to deliver the McFaddens-Dallington, Bromley-Dallington and Bromley-Rawhiti projects on time. To ensure that we have timely access to civil works contractors and we can deliver these projects in a manner that meets SCIRT's coordination requirements, we will contract directly with SCIRT for the civil works component of these projects.

The installation of the cable will involve SCIRT (McConnell Dowell and Fletchers for civil works), General Cables (cable, termination, jointing and testing), and Connetics (installation of cable).

A formal agreement has been prepared in line with the current SCIRT alliance contracting model. This agreement is a target cost agreement where the parties are subject to elements of cost and profit sharing for actual costs above or below the target cost. This agreement has been prepared and reviewed by Chapman Tripp acting on our behalf.

The process for establishing the target cost for the works has been:

- SCIRT contractors prepare cost estimates
- SCIRT estimator reviews cost estimates
- Orion reviews estimate with an independent quantity surveyor
- negotiate and finalise cost estimate with SCIRT.

Following significant negotiation with SCIRT, overall installation costs are estimated at a rate of $690 per metre for the McFaddens-Dallington 66kV cable project. This project is a cost and profit sharing arrangement with potential for costs to exceed $690 per metre. For our CPP project cost estimation we have assumed $700 per metre.

The Bromley to Dallington cable route passes through an area of potential lateral ground movement and includes a river crossing. This will increase the level of engineering required. The Lancaster to Milton cable route requires a rail crossing and is a relatively short length, which increases the overhead costs on a per metre basis. Our CPP project cost estimation assumes $750 per metre for these two projects.

The cable route for the Hawthornden-Waimakiriri-Marshland-Rawhiti projects is not likely to require the same level of coordination with SCIRT. The completion dates between FY15 and FY17 will mean that we have more time to investigate and negotiate alternative options for the civil works components of these projects. While this may not result in a cost saving on the $700 per metre it may give other benefits including the flexibility to better coordinate with our other network upgrade projects.

9.13.12 Major projects – identified

IM D7(2) (4) and (5)

Urban major projects – North

Our Urban Major Project – North is included as an identified project. The following information is provided in response to the requirements of Schedule D7(2). More extensive explanations are provided in our CPP1 Project Summary document.

Identified project – CPP1 - urban north	
D7(2)	**Explanation**
(a) description including aims and objectives	Our plans to expand our sub transmission network in northern and western Christchurch have been in preparation for some years. The earthquakes have altered these plans, due to asset damage in the east city and changes to load growth forecasts. The objectives of this suite of projects are: • to restore N-1 security of supply to Rawhiti zone substation, following the destruction of two Bromley-Brighton cables and Brighton zone substation. This will be done in a way consistent with the network architecture proposed by the Architecture Review, i.e. a cable from Bromley and one from Islington via Waimakariri and Marshland • to provide capacity and security of supply to north and northwest Christchurch, as load develops (hastened by post-earthquake relocation of demand) • to provide for the replacement of the four Papanui 66/11kV transformers, according to Orion's chosen network architecture. This means the reduction of firm capacity from 76 to 40MVA, and the transfer of load to other zone substations
(b) deliverability	At a high level, this project mainly requires the use of 66kV underground cable and zone substation contractors. This resource is also required on a number of other projects to be completed within our AMP 10 year planning timeframe. A dominant factor in prioritising this project is the requirement to remove the 66kV temporary overhead line from Bromley to Rawhiti by 2014. Replacement of end-of-life assets and coordination with Transpower works also influence the staging of these projects. More information about how we prioritise our projects is set out in Section 9.13.4 above
(c) contingency factors	There are no contingency factors provided for in this project
(d) assumptions, obligations and step changes	An external obligation is the expiry in 2014 of the emergency Civil Defence resource consent for the single circuit temporary Bromley-Rawhiti 66kV overhead line, which has determined the timing of our forecast major cable investment. Our project is also consistent with local authority plans and requirements - which require all new electricity reticulation to be underground in the urban area. Our other major obligations are set out in our Statutory Compliance Manual. This project comprises the following key developments:

Development	**Year**	**Real ($m)**
QEII Park diesel generators	FY13	2.9
Land acquisition for Marshland substation	FY14	0.5
Bromley to Rawhiti 66kV link	FY14	11.0
Waimakariri substation stage 1	FY15	5.3
Hawthornden-Waimakariri 66kV link	FY15	7.5
Marshland to Waimakariri 66kV link	FY15	10.7
Belfast diesel generation stage 1	FY16	1.3
Rawhiti to Marshland 66kV link	FY16	11.4
Marshlands zone substation	FY18	6.3
Hawthornden T-off	FY18	1.3
Waimakariri substation stage 2	FY18	2.4

Of the total project cost approximately 60% is associated with sub transmission cable, 12% with generators and the remainder is substations. A full description of the assets to be constructed is included in Section 4 of the CPP1 Project Summary.

Key assumptions relevant to this project include:

- network constraints and timing
- forecast load
- network options
- non network alternatives.

Each of these is discussed in Section 3 of the CPP1 Project Summary.

In addition the relevant policies and planning standards for this project are described in Section 2 of the CPP1 Project Summary.

(e) departures from consultants recommendations	There are no departures from consultants' recommendations in this capex project
(f) forecasting methodology	The forecast costs for this capex project are derived using our costing methodology described in Section 9.13.10 above, supported by our Project Budget Forecasting Process Document (NW70.60.13). These are forecast consistent with our cost escalation approach which is described in Section 9.26 below. Our construction cost benchmarks (included in Appendix 27) show that our sub transmission cable and zone substation costs were below the industry average for all asset components surveyed. Updated quotes for 66kV cable materials have been recently obtained. The QEII generator costs reflect actual expenditure already incurred. All other categories involve infrastructure which we install regularly and for which there is recent history.

Urban major project – Dallington

Our Urban Dallington project is also an identified project. The following information is provided in response to the requirements of Schedule D7(2). More extensive explanations are provided in our CPP2 Project Summary document.

<table>
<tr><th colspan="4">Identified project – CPP2 – urban Dallington</th></tr>
<tr><th>D7(2)</th><th colspan="3">Explanation</th></tr>
<tr><td>(a) description including aims and objectives</td><td colspan="3">Plans to expand our sub transmission network in northern and western Christchurch have been in preparation for some years. The earthquakes have altered these plans, due to asset damage in the east city and changes to load growth forecasts. A high-capacity cable from Bromley to Dallington was planned to be laid when the capacity of the existing circuits was exceeded. The destruction of these cables necessitated an emergency temporary overhead supply and the plan for a new Bromley-Dallington cable has been advanced to be built before the expiry of the consent for the overhead line. The McFaddens-Dallington cable is being built as soon as is practical to provide security of supply to the suburbs of Avondale, Shirley, Dallington, Aranui, Avonside and Wainoni.
The objectives of this suite of projects are:
• to restore N-1 security of supply to the Dallington zone substation, following the destruction of two Bromley-Brighton cables. This will be done in a way consistent with the network architecture proposed by the Architecture Review, i.e. a cable from Bromley and one from Islington via Papanui and McFaddens
• to reinforce security of supply to east and north Christchurch by completing one of four major cross GXP links between Islington and Bromley</td></tr>
<tr><td>(b) deliverability</td><td colspan="3">Like the urban north project, this project mainly requires the use of 66kV underground cable and zone substation contractors. This resource is also required on a number of other projects to be completed within our AMP 10 year planning timeframe. A dominant factor in prioritising this project is the emergency resource consent requirement to remove the 66kV temporary overhead line from Bromley to Rawhiti by 2014. Replacement of end-of-life assets and coordination with Transpower works also influence the staging of these projects. More information about how we prioritise our projects is set out in Section 9.13.4 above</td></tr>
<tr><td>(c) contingency factors</td><td colspan="3">There are no contingency factors provided for in this project</td></tr>
<tr><td rowspan="3">(d) assumptions, obligations and step changes</td><td colspan="3">An external obligation is the expiry in 2014 of the emergency resource consent for the temporary Bromley-Rawhiti 66kV overhead line, which has determined the timing of major cable investment. Our project is also consistent with local authority plans and requirements which require new electricity infrastructure to be underground in the urban area. Our other major obligations are set out in our Statutory Compliance Manual.
This project comprises the following key developments:</td></tr>
<tr><td>Development</td><td>Year</td><td>Real ($m)</td></tr>
<tr><td>Dallington to McFaddens 66kV link stage 2</td><td>FY13</td><td>8.3</td></tr>
</table>

Bromley to Dallington 66kV link stage 1	FY13	1.6
Bromley to Dallington 66kV link stage 2	FY14	9.6

Of the total forecast project cost more than 90% is associated with sub transmission cable, 7% with switchgear and the remainder is secondary systems. A full description of the assets to be constructed is included in Section 4 of the CPP2 Project Summary.

Key assumptions relevant to this project include:

- network constraints and timing
- forecast load
- network security
- network options
- non network alternatives.

Each of these is discussed in Section 3 of the CPP2 Project Summary.

In addition the relevant policies and planning standards for this project are described in Section 2 of the CPP2 Project Summary.

(e) departures from consultants recommendations	There are no departures from consultants' recommendations in this capex project
(f) forecasting methodology	The forecast cost for this capex project is derived using our costing methodology described in Section 9.13.10 above, supported by our Project Budget Forecasting Process Document (NW70.60.13). These are forecast consistent with our cost escalation approach which is described in Section 9.26 below. Our construction cost benchmarks (included in Appendix 27) show that our sub transmission cable and zone substation costs were below the industry average for all asset components surveyed. Updated quotes for 66kV cable materials have been recently obtained.

Rural major project – Rolleston

Our Rural Rolleston project is also an identified project. The following information is provided in response to the requirements of D7(2). More extensive explanations are provided in our CPP7 Project Summary document.

Identified project – CPP7 – rural Rolleston

D7(2)	Explanation
(a) description including aims and objectives	This project is designed to meet strong residential and industrial growth in the Rolleston and wider Rolleston area. The Rolleston area is the hub of the SDC area and there is a council and community expectation that infrastructure in the area will develop to meet the needs of the types of industries locating there. Historically the load has been modest and our simple traditional rural 33kV subtransmission network design has reflected this. Going forward we need to recognise the transition from a small township to a major residential and industrial load centre.

<table>
<tr><td></td><td>This project will continue with the development of an N-1 sub transmission network for Rolleston and also create greater flexibility for the development of a more interconnected sub transmission network for the wider rural area. The proposed transition to a 66kV sub transmission network will relieve capacity constraints on the 33kV network and will also relieve constraints on Transpower's Springston 66kV GXP. This project is also consistent with our strategy to exit 33kV sub transmission where technically and economically viable.
The assets to be modified or built from new include the following zone substations and associated 66kV sub transmission lines: Rolleston, Burnham (replacement for Rolleston), Larcomb, Weedons, Highfield, Springston and Rossendale (proposed). The projects already completed in this long-term strategic plan include 33kV zone substations at Weedons (FY87), Highfield (FY03) and Larcomb (FY09) and their feeder lines. Weedons was converted to 66kV in FY12 and the others will follow as part of this project.</td></tr>
<tr><td>(b) deliverability</td><td>This project mainly requires the use of 66kV overhead line and zone substation contractors. This resource is also required on a number of other projects to be completed within our AMP 10 year planning timeframe. A dominant factor in prioritising this project is the anticipated 9.4MVA N-1 Westland Milk connection in spring 2014, which sets the timing for the early stages of this project. More information about how we prioritise our projects is set out in Section 9.13.4 above</td></tr>
<tr><td>(c) contingency factors</td><td>There are no contingency factors provided for in this project</td></tr>
<tr><td>(d) assumptions, obligations and step changes</td><td>Our project is consistent with local authority plans and requirements which require new electricity infrastructure to be underground in the urban area. Our other major obligations are set out in our Statutory Compliance Manual.
This project comprises the following key developments:
<table>
<tr><th>Development</th><th>Year</th><th>Real ($m)</th></tr>
<tr><td>Larcomb to Weedons 66kV line conversion</td><td>FY13</td><td>0.5</td></tr>
<tr><td>Convert Larcomb sub from 33/11kV to 66/11kV</td><td>FY14</td><td>3.2</td></tr>
<tr><td>Springston 66kV bay for Larcomb substation</td><td>FY14</td><td>0.3</td></tr>
<tr><td>Land acquisition for Burnham 66kV substation</td><td>FY14</td><td>0.3</td></tr>
<tr><td>Land acquisition for Rosendale substation</td><td>FY14</td><td>0.3</td></tr>
<tr><td>Railway Road substation (Westland Milk)</td><td>FY14</td><td>3.1</td></tr>
<tr><td>Burnham substation stage 1</td><td>FY15</td><td>3.6</td></tr>
<tr><td>Weedons to Highfield tee 66kV line conversion</td><td>FY17</td><td>1.6</td></tr>
<tr><td>Convert Highfield zone substation to 66/11kV</td><td>FY18</td><td>0.7</td></tr>
</table>
Of the total forecast project cost, approximately 40% is associated with zone substations, 10% subtransmission lines, 25% switchgear and the remainder distribution and supporting or secondary systems. A full description of the assets to be constructed is included in Section 4 of the CPP7 Project Summary.
Key assumptions relevant to this project include:
• security of supply standard</td></tr>
</table>

	• tenure of substation sites, corridors and cable routes • network constraints and timing • reliability objectives • forecast load including Westland Milk's requirements • network options and supporting economic analysis • non network alternatives Each of these is discussed in Section 3 of the CPP7 Project Summary. In addition the relevant policies and planning standards for this project are described in Section 2 of the CPP7 Project Summary.
(e) departures from consultants recommendations	There are no departures from consultants' recommendations in this capex project
(f) forecasting methodology	The forecast cost for this capex project is derived using our costing methodology described in Section 9.13.10 above, supported by our Project Budget Forecasting Process Document (NW70.60.13). These are forecast consistent with our cost escalation approach which is described in Section 9.26 below. Our construction cost benchmarks (included in Appendix 27) show that our sub transmission cable and zone substation costs were below the industry average for all asset components surveyed. All other categories involve infrastructure which Orion installs regularly and for which there is recent history.

Spur asset acquisitions

Our spur asset acquisitions are included as an identified project. The following information is provided in response to the requirements of D7(2). More extensive explanations are provided in our CPP54 Project Summary document.

Identified project – CPP 54 – Spur asset acquisitions

D7(2)	Explanation
(a) description including aims and objectives	Orion purchased the Papanui GXP and associated spur asset lines from Transpower in August 2012. This project is a continuation of that initiative and includes the purchase of eight Transpower spur asset GXPs and associated spur asset lines. The proposed spur assets to be purchased include the: • Islington to Springston 66kV lines and Springton 66kV and 33kV GXPs • Islington to Addington 66kV lines and Addington 66kV and 11kV GXPs • Middleton 66kV GXP • Arthurs Pass 11kV GXP including the 66/11kV transformer – the change of ownership boundary will be at 66kV • Castle Hill 11kV GXP including the 66/11kV transformer – the change of ownership boundary will be at 66kV • Hororata 33kV GXP (Hororata 66kV to remain in Transpower ownership) • Bromley 66KV and 11kV GXP (Bromley 220KV to remain in Transpower ownership) • Islington 33kV GXP (Islington 220/33kV transformers to remain in

	Transpower ownership) These spur assets are dedicated to supplying Orion’s network and serve the purpose of local distribution rather than national transmission. A change of ownership therefore enables synergies and efficiencies to be gained through integration into local distribution network asset planning, management, maintenance and operations. Thus the main aim of this project is secure a change of ownership of spur assets so that future network efficiencies and benefits will ultimately flow through as benefits for our consumers. For example the recent purchase of the 66kV assets at Papanui will enable us to defer the replacement of the 66/11kV transformers and have greater flexibility in the architecture of our sub transmission network which is expected to lead to a saving of more than $5m. Similar benefits are expected across all spur assets purchase projects. Other key drivers for this project are: • returning our network to a state that meets our Security of Supply Standard (SoSS) in the most cost-effective way possible (as set out in our sub transmission architecture review) • completing the spur asset transfers in a timeframe that prevents Transpower investment in replacing assets which we are able to achieve by more cost-effectively rationalising the assets • in the case of the Springston GXP, the spur asset purchase will facilitate parallel operation of assets with existing Orion 66kV assets and therefore deliver an N-1 security of supply to the wider Rolleston area. The capital funding, maintenance and operations costs associated with Transpower ownership of the spur assets is currently charged to Orion as 'Connection Charges'. Orion passes these charges through to consumers. When the spur asset change of ownership occurs, Transpower will discontinue the associated 'Connection Charges'. Orion will recover its costs associated with owning and maintaining the spur assets via distribution charges. Over the lifetime of the assets, the synergy and efficiency benefits associated with Orion ownership of these assets will mean that the increase in Orion revenue will be lower than the equivalent Transpower connection charges. This will be of real benefit to consumers.
(b) deliverability	There are no material works to be undertaken as part of this project. There will be incidental works associated with the spur assets but these are included in our lifecycle management (replacement capex and maintenance opex) costs. The proposed spur asset transfer dates have been agreed by Transpower and Orion, after taking account internal resource availability, and the need to progress spur asset transfers soon to avoid unnecessary asset replacement investment in the meantime. In some cases Transpower has agreed to delay replacement works. The Springston spur asset transfer has become the immediate priority so that the sub transmission network in the wider Rolleston area can be improved to N-1 security.

<table>
<tr><td>(c) contingency factors</td><td>There are no contingency factors provided for in this project</td></tr>
<tr><td>(d) assumptions, obligations and step changes</td><td>An external obligation is the expiry in 2014 of the consent for the temporary Bromley-Rawhiti 66kV overhead line, which has determined the timing of major cable investment. Our project is also consistent with local authority plans and requirements which require new electricity infrastructure to be underground in the urban area. Our other major obligations are set out in our Statutory Compliance Manual.
The purchase of these Transpower spur assets is fundamental to many of our major urban and rural sub transmission projects including upgrading our network to ensure it meets our Security of Supply Standard (SoSS). If this project was unsuccessful it would lead to changes to our major project designs and budgets, and may delay our compliance with our SoSS for parts of our network.
This project comprises the following key developments:
<table>
<tr><th>Purchase</th><th>Year</th><th>Nominal ($m)</th></tr>
<tr><td>Springston GXP and 66kV lines</td><td>FY14</td><td>2.7</td></tr>
<tr><td>Addington GXP and 66kV lines</td><td>FY15</td><td>13.8</td></tr>
<tr><td>Middleton GXP</td><td>FY15</td><td>0.3</td></tr>
<tr><td>Arthurs Pass 11kV and 66/11kV transformer</td><td>FY15</td><td>2.0</td></tr>
<tr><td>Castle Hill 11kV and 66/11kV transformer</td><td>FY15</td><td>0.7</td></tr>
<tr><td>Hororata 33kV and 66/33kV transformers</td><td>FY16</td><td>0.6</td></tr>
<tr><td>Bromley 66kV and 11kV</td><td>FY16</td><td>8.8</td></tr>
<tr><td>Islington 33kV</td><td>FY17</td><td>1.2</td></tr>
</table>
Key assumptions relevant to this project include:
• network constraints and service obligations
• forecast load
• non network alternatives
Each of these is discussed in Section 3 of the CPP54 Project Summary.
In addition the relevant policies and planning standards for this project are described in Section 2 of the CPP54 Project Summary.</td></tr>
<tr><td>(e) departures from consultants recommendations</td><td>There are no departures from consultants’ recommendations in this capex project</td></tr>
<tr><td>(f) forecasting methodology</td><td>The spur assets are forecast to be purchased at their regulatory asset value, consistent with Transpower’s regulatory asset register. The forecast costs outlined above therefore reflect their estimated depreciated value at purchase date. Our method for estimating these values is described in Section 7.6.5 of this proposal.</td></tr>
</table>

9.13.13 Major projects – other

IM D7 (6)

The remaining major projects have not been selected as identified projects. The Schedule D information requirements are less comprehensive for these projects. Notwithstanding this, we have prepared project summaries for each of them which are provided as supporting material to this proposal.

Explanations for each of these are included in their Project Summary documents. A full list of these is set out below with a brief description of each project:

Major projects (not included as an identified projects)		
Reference	**Project Name**	**Description**
CPP3	Urban West	The objective of this suite of projects is to provide for load growth in the west of Christchurch. Substantial industrial developments are planned in the South Hornby area, and residential growth around Templeton. The capacity of the existing zone substations in the area – Moffett, Shands and Hornby – will become insufficient as this load develops. A new zone substation at Templeton underneath the Islington-Weedons 66kV line is envisaged, and while this will be required outside the CPP period a suitable site will need to be acquired. The Moffett 33/11kV zone substation has a firm transformer capacity of 23MVA but the 33kV and 11kV incomer cables restrict the site to less than 20MVA firm. An upgrade of these cables will enable the full transformer rating to be realised. There are a number of options for increasing capacity in the South Hornby area in addition to the Moffett upgrade. While the preferred solution has yet to be determined, the likely candidate is the conversion of Shands 33/11kV 23MVA zone substation to 66/11kV 40MVA. This will necessitate the purchase of additional land for a 66kV switchyard
CPP4	Urban Southeast	The long-term objective of this suite of projects is to provide the reliability and security of supply benefits of a closed sub transmission ring for seven zone substations in southeast Christchurch, with a potential load of 230MVA. Increased capacity and flexibility of supply around central Christchurch and inter-GXP tie capacity all improve the resiliency of the upper network. Load transfer from Islington GXP to Bromley GXP is also achieved, optimising the interconnection assets. Most of the investment is outside the CPP period. While there are other possible solutions to provide for load growth in the southeast (which is expected to be slower than other areas), the rationale for these projects is to strengthen our ability to keep the power on in a range of predictable and unforeseen contingencies, and directly follows the post-earthquake review of risk management. The Lancaster to Milton cable will require 66kV switchgear installations at Lancaster and Milton zone substations. The purchase of additional land for a 66kV switchroom at Milton will be necessary. Similarly the proposed Milton-Hoon Hay cable will require a 66kV switchyard at Hoon Hay. A suitable site will be acquired

CPP5	Urban South	Plans for a 66kV zone substation at Awatea supplied from the Islington-Halswell tower lines have been in preparation for some time, to provide capacity and improve security of supply to the Wigram, Awatea and northeast Prebbleton districts. This is an area of active development which is expected to accelerate after the earthquakes. A suitable property for the Awatea substation has already been acquired, but a condition of purchase requires Orion to undertake land remediation. This project addresses that commitment.
CPP6	Urban CBD	The Christchurch Central Recovery Plan specifies the urban planning framework for the CBD. It incorporates the “Frame,” a zone without buildings which, along with the Avon River, surrounds the proposed central city. The intention is for all buildings in the Frame to be demolished and replaced by paving and landscaped areas. Two of our zone substations are located in the CBD Frame. The Christchurch Central Development Unit (CCDU) has decided that the cost of demolishing and rebuilding these (and rerouting 66kV, 11kV and communications cabling) is prohibitive and that the structures will have to be incorporated into the landscape. A budget is accordingly set aside for landscaping and modifications to the exterior of our buildings and fencing
CPP8	Rural Hororata / Creyke 66kV	This project is a series of six AMP projects designed to meet load growth in the wider Hororata and Darfield area while transitioning from 33kV to 66kV sub transmission. This project is consistent with the development of a more interconnected 66kV sub transmission network for the wider rural area. The proposed transition to a 66kV subtransmission network will relieve capacity constraints on the 66/33kV transformers at Hororata GXP. The assets to be modified or built from new include the following zone substations and associated 66kV subtransmission lines: Creyke, Darfield (to be decommissioned beyond FY19), Hororata, Bankside and Annat. This project also includes the installation of 11kV ripple plants at Annat and Bankside zone substations.
CPP9	Rural Central Plains	This project provides major reinforcement to supply electricity for pumping in the Central Plains Water scheme. This project involves substantial 11kV reinforcement plus a dedicated 66kV substation. The Central Plains Water scheme has recently received final resource consents from the Environment Court and construction for Stage I is expected in FY15. This stage will involve four 200kW pumps between Te Pirita and Hororata. This will stretch the transformation capacity at Te Pirita and Hororata, but these constraints are addressed elsewhere as part of the overall rural subtransmission strategy. The local 11kV network cannot support an extra 800kW, and so reinforcement is required.
CPP10	Rural Springston	This project is a series of four AMP projects designed to meet strong residential growth in the Lincoln and wider Springston area. The projects in this group together prepare for a new 66/11kV 7.5/10MVA zone substation at Greenpark and the conversion of Springston zone substation to 66/11kV (both outside the CPP horizon).
CPP11	Rural Norwood	This suite of three AMP projects provides a new 66/11kV zone substation in the Norwood district. It ensures capacity and security of supply in a manner consistent with the overall rural sub transmission strategy.

CPP12	Rural Power Factor	Our rural network is for the most voltage constrained. The limit to increasing load on a feeder is reached when the voltage drop becomes excessive, rather than when the conductor thermal ratings are reached. This project provides for power factor correction (PFC) and voltage support on our rural network. These assets increase capacity on the overhead network, reduce losses, improve power quality and reduce transmission costs in the likely event of reactive off-take charges being introduced in the Upper South Island. Other economic benefits of network capacitance include reduction in demand for peaking generation.
CPP13	Rural Annat	This project provides for a 33/11kV transformer upgrade at Annat zone substation, to supply electricity for pumping in the Central Plains Water scheme
CPP14	Rural Banks Peninsula	This project optimises 33/11kV transformer assets on our rural network. A transformer which will become available when the Kimberley zone substation is upgraded to 66kV will be moved to another location in Banks Peninsula, allowing other beneficial asset shifts to take place without the need to purchase new banks
CPP15	Rural Southbridge	Capacity of supply in the Rakaia-Southbridge district is becoming stretched by the continuing growth in dairy farming and residential township growth. The neighbouring zone substations (Killinchy and Brookside) are close to capacity in the summer so the ability of these three substations to support each other in an outage is becoming compromised. This project provides a new 66/11kV zone substation in the Southbridge district. It ensures capacity and security of supply for the south eastern part of our network in a manner consistent with the overall rural sub transmission strategy and allows for the eventual removal of 33kV assets
CPP16	Rural Dunsandel	The Dunsandel zone substation was installed to provide for the Synlait dairy factory. Synlait are planning to add two more dryers to their plant which will exceed the capacity of the existing 10MVA transformers. Dunsandel supplies general load in the district in addition to the Synlait demand, and this load is also growing. This project provides for a pair of 23MVA banks, and allows the 10MVA units to be used elsewhere in the network without the need to purchase new banks
CPP17	Rural Porters Heights	A proposed alpine village and winter sports resort near Porters Pass has received resource consent and construction is scheduled to begin in FY15. The projected magnitude of load and the remote location means that major sub transmission and distribution works will be required. This connection presents some unique challenges. A high-level preliminary investigation has been undertaken but detailed design is yet to be done. Possible options include: • a new 66kV GXP at Porters Heights • a 33kV supply from Castle Hill GXP with a 33/11kV zone substation at the village, and distribution at 11kV • a 22kV supply from Castle Hill GXP with distribution at 22kV As the 22kV option has been identified as the most cost-effective solution the budget has been estimated on that basis. However, 22kV is not an Orion standard technology and we have not adopted 22kV
CPP18	Rural Kimberley	This project is designed to meet Fonterra Milk Powder Factory load and rural growth in the Kimberley and wider Darfield area. The dairy factory entered

		production in 2012 with one dryer and is planning to grow significantly over the next five years requiring an upgrade to 66 kV and the installation of a Transpower GXP. The assets to be modified or built from new include the following zone substations and associated 66kV sub transmission lines: Transpower's Islington to Hororata 66 kV transmission circuits, Kimberley 33/66 kV circuits and upgrade of the Orion Kimberley substation (presently 33 kV)
CPP19	Rural Alpine	This project provides for diesel generators within the Alpine area of our rural network. The remote nature and alpine environment has led to a higher than normal number of outages. The aim of this project is to improve the security and reliability of supply for Castle Hill and Arthur's Pass GXPs, reduce total network peak load and assist with the avoidance of shutdowns for planned maintenance.
CPP20	Rural GFN	In 2006 we began investigating the use of ground fault neutralisers (resonant earthing coils with residual current compensation) in the neutral circuit of rural zone substation transformers. We decided to install GFNs in all rural substations. This roll-out has proceeded in stages and the installations in this project will complete the retro-fitting plan.

Appendix 21 explains which of our policy documents are relevant to these projects.

The project costs for all of our major projects are derived consistent with the method described in Section 9.3.10 above and our cost escalation assumptions described in Section 9.26.

In addition, as stated earlier, there are no contingency factors provided for within our major capex project CPP forecasts.

9.14 Reinforcement capex

IM D10

Our reinforcement capex category most closely aligns with the CPP IM reliability, safety and environment capex category. Accordingly we have addressed the requirements of Schedule D10 in this section of our proposal.

Aims and objectives

The objective of reinforcement capex is to increase the capacity of the 11kV network to provide for projected increases in load, and to extend its reach as new areas are developed. The key drivers for reinforcement projects include:

- as general demand grows on the established network, the security of supply is eroded. The updating of load-flow models for feeder or substation outages identifies the areas of constraint, usually due to the thermal rating of cables
- new connections involving large point loads, which cannot be supplied on the existing network
- development of vacant land often requires the 11kV network to be extended.

Key features

Our reinforcement capex programme is made up of the following individual programmes.

Capex – Reinforcement

Reference	Project Name	Nominal value over next period ($m)	Identified project
CPP51	Urban reinforcement	25.0	Yes
CPP52	Rural reinforcement	14.2	

As consumer demand grows, the security of supply available on the network (which is provided by redundant capacity) is eroded and eventually capacity is exceeded. Investment is needed before the security of supply standard is violated by increased demand on existing circuits, or connecting new load which has no or insufficient network capacity nearby.

Reinforcement projects are key to continuing to meet our reliability targets within our existing network.

This work is done in response to customer or developer applications, or modelling general load growth on the existing network to identify constraints. Budgets are set on the basis of historical trends and growth forecasts.

Network utilisation thresholds

Our network utilisation thresholds are used to assist us to prepare our annual reinforcement programme for our network. These thresholds and the interrelationships with our system security standards and load growth are explained above in Section 9.13.6, in relation to major project capex.

Non network alternatives

We do not provide off-grid solutions (which may be investigated independently by consumers). However, non-network solutions may form part of the decision regarding the trade-off between cost and security of supply, for example in the use of consumer-owned generation.

We provide strong cost reflective price signals that help create a market for non-network alternatives, without dictating their form. These peak-pricing signals have resulted in consumer behaviour that reduces unnecessary expenditure by users and therefore costs to consumers.

We aim to be a leader in demand side management and peak pricing. We have provided:

- twenty years of real-time peak pricing to major consumers
- fourteen years of peak pricing to retailers to support day/night pricing to households and businesses
- USI load management for eight networks.

These initiatives have resulted in cost savings through more than 20 MW of stand-by generation invested in by consumers.

Deliverability and prioritisation

11kV reinforcement uses similar contracting resources to connection and undergrounding work and is managed as part of the contracting workflow. Our work on the winter-peaking urban network is typically done in the summer, which balances naturally with rural works largely undertaken in winter.

Reinforcement is co-ordinated when feasible with other civil works such as roading, water and telecommunications, especially in new subdivisions. It may be co-ordinated with our other infrastructure works – especially if connection, extension or undergrounding is also involved.

Documents, policies and consultants reports

These projects include a large variety of work and the detailed design and construction will be in line with our design standards, technical specifications and policies as summarised in NW 70.50.03 – Document Control. In particular urban reinforcement works will be implemented in compliance with the following sections:

- 9.2 Infrastructure
    - 9.2.1 Management
    - 9.2.3 Design Standards
    - 9.2.4 Technical Specifications

- 9.5 Contracts
    - 9.5.1 Management
- 9.7 Procurement & Stock Management
    - 9.7.2 Equipment Specifications

Their relevance to asset reinforcement capex is summarised in Appendix 21.

Obligations

IM D10(a)(b)

We are subject to a number of obligations included in a wide range of legislation. Our main obligations are contained in our Statutory Compliance Manual. In addition in respect of reinforcement projects, maintaining our network security of supply standard is of paramount importance. This is set out in Section 6.2.7. Meeting our reliability targets is also of direct relevance to reinforcement projects. These are discussed more fully in Section 9.6 above.

There are no new obligations which have been specifically accounted for in our capex forecast.

Risk management

IM D10(c)

Clause D10 requires us to describe our:

- risk management policies

- risk assessments and risk mitigation or risk prevention measures we have employed during the current period
- risk mitigation measures identified and proposed to be deployed in the next period.

This is set out in detail in Section 9.9 above.

Other risk related policies are summarised in our Document Control Policy (NW70.50.03) and are listed in Appendix 21.

9.14.1 Reinforcement projects

IM D7 (6)

Explanations for each reinforcement project are included in their Project Summary documents. A full list of these is set out below:

- CPP51 – Urban Reinforcement – Project Summary
- CPP52 – Rural Reinforcement – Project Summary.

Appendix 21 also explains which of our policy documents are relevant to these reinforcement projects.

The projects costs for our reinforcement projects are derived using the same method as for our major project capex – described in Section 9.13.10 above and our cost escalation assumptions described in Section 9.26.

As stated earlier, there are no contingency factors provided for within the reinforcement capex programme.

Our urban reinforcement project has been selected as an identified project. The following information is provided in response to the requirements of D7(2). More extensive explanations are provided in our CPP51 Project Summary document.

Identified project – CPP51 – Urban reinforcement	
D7(2)	**Explanation**
(a) description including aims and objectives	As demand grows, the security of supply available on the network (which is provided by additional capacity above that normally required) is eroded and eventually normal supply capacity is exceeded. Investment is needed before the security of supply standard is violated by increased demand on existing circuits, or connecting new load which has no or insufficient network capacity nearby. 11kV investment which is not part of the Connections and Extensions or Undergrounding budgets, is classed as reinforcement. This budget consistent of multiple single-year projects. Key drivers for this project are: • as general demand grows on the established network, the security of supply is reduced. The updating of load-flow models for feeder or substation outages identifies the areas of constraint within the network, usually due to the thermal rating of cables • new connections involving large point loads, which cannot be supplied on the existing network. • to provide distribution assets for new connections such that they: - meet acceptable target levels of safety to people and property

<table>
<tr><td></td><td>- provide acceptable levels of network reliability
• development of vacant land often requires the 11kV network to be extended
• balancing the need for adequate future capacity with the need for cost effectiveness.</td></tr>
<tr><td>(b) deliverability</td><td>11kV reinforcement uses similar contracting resources as connections and undergrounding work and is managed via our contractor workflow processes. Work on the winter peaking urban network is typically done in summer which balances naturally with rural works undertaken in winter. More information about how we prioritise our projects is set out in Section 9.13.4 above</td></tr>
<tr><td>(c) contingency factors</td><td>There are no contingency factors provided for in this project</td></tr>
<tr><td>(d) assumptions, obligations and step changes</td><td>Our project is also consistent with our obligations in respect of local authority plans and requirements which require new electricity infrastructure to be underground in the urban area. Our other major obligations are set out in our Statutory Compliance Manual.
This project comprises the following annual expenditure ($m real):
<table>
<tr><th>FY13</th><th>FY14</th><th>FY15</th><th>FY16</th><th>FY17</th><th>FY18</th><th>FY19</th></tr>
<tr><td>1.7</td><td>3.9</td><td>3.8</td><td>2.3</td><td>2.9</td><td>3.0</td><td>2.3</td></tr>
</table>
This mainly comprises 11kV underground cables with associated distribution transformers and substations. The FY13 year is lower than typical because of residential and urban relocation. FY14 and FY15 reflect planned works. Works are generally planned beyond a two to three year window at this level of the network, so the out years revert to a lower historical average level of investment. Key assumptions relevant to this project include:
• security or capacity constraints
• power quality
• co-ordination with other infrastructure works
• geotechnical conditions
• forecast demand
Each of these is discussed in sections 3 and 4 of the CPP51 Project Summary. In addition the relevant policies and planning standards for this project are described in Section 2 of the CPP51 Project Summary.</td></tr>
<tr><td>(e) departures from consultants recommendations</td><td>There are no departures from consultants’ recommendations in this capex project</td></tr>
<tr><td>(f) forecasting methodology</td><td>The cost for this capex project is derived using our costing methodology described in Section 9.13.10 above, supported by our Project Budget Forecasting Process Document (NW70.60.13). These are projected forward consistent with our cost escalation approach which is described in Section 9.26 below. Our assessment of the level of work required is explained in response to (d) above and more fully in our CPP51 Project Summary document.</td></tr>
</table>

9.15 Replacement capex

Aims and objectives

The aims and objectives of our network replacement capex programmes include the following:

- ensure the safety of the public and our personnel and contractors around our assets
- replace on an periodic basis assets for which it has been determined that replacement is the cost effective way to ensure reliability of electricity supply and meet service level targets.
- assist to maintain the age profile of our assets to ensure future replacement can be managed without unnecessary peaks
- achieve lowest life time cost for assets
- introduce new improved equipment types when appropriate in a timely way
- facilitate our maintenance and major capex programmes where appropriate.

Key features

Our replacement capex programme is made up of the following individual programmes:

Capex – Replacement			
Reference	**Programme name**	**Nominal value over next period ($m)**	**Identified project**
CPP30	Overhead lines sub transmission	5.4	
CPP31	Overhead lines 11kV and 400V	23.7	
CPP41	Underground cables sub transmission	0.1	
CPP32	Underground cables 11kV and 400V	18.1	
CPP33	Communications and protection	20.9	Yes
CPP34	Control systems	11.6	
CPP36	Switchgear	71.0	Yes
CPP37	Transformers	15.1	Yes
CPP38	Substations	3.5	
CPP39	Buildings and grounds	7.9	
CPP40	Meters	0.9	

CPP35	Load management systems	5.6
CPP42	Asset management system	4.2
CPP43	Distribution management systems	5.0

Each of these replacement programmes is documented in a Project Summary document. In addition each Project Summary document for asset replacement capex is supported by a number of Asset Management Reports (addressing different types of asset within each asset class). The Asset Management Reports summarise the criteria and asset management practices used to ensure that effective performance and an acceptable service life is achieved for each asset class. The Asset Management Reports address both replacement (capex) and maintenance (opex) activities.

The Project Summary documents and associated Asset Management Reports for the identified programmes are included as supporting documents to this proposal. The remaining Project Summary Documents and Asset Management Reports are available as supporting documents to our CPP Proposal.

A notable feature of our replacement capex programme is the increased expenditure on 11kV and 400V cable replacements in order to recover the condition of our underground distribution network following earthquake damage. In addition we are investing significantly in switchgear replacement. The step up in FY13 reflects in part our deferral of planned replacements in FY11 and FY12 due to the need to prioritise earthquake related expenditure in those years.

Approach to asset replacement

We assess and proactively replace network equipment that is nearing the end of its life expectancy. This assessment is carried out using a risk based approach and by looking at whole-of-life cost. The risk based approach is based on three characteristics of failure – frequency, consequence and context.

Condition based risk management

With the assistance of EAT we are currently in the process of implementing CBRM. The CBRM models use the results from our condition monitoring programmes and underpin the economic justification for our expenditure forecasts. We are currently halfway through the CBRM project and expect to have the models completed in FY13. Although we are well advanced with the CBRM modelling, this information has not yet been factored into our overall replacement planning approach. This is an area of development and improvement for us, and unfortunately the earthquakes have forced us to defer our development of this methodology as we have concentrated on post-earthquake restoration and recovery.

A copy of the March 2012 EA CBRM report is provided as supporting documentation.

CBRM models use asset information and engineering knowledge and experience to define, justify and target asset renewal. They provide a proven and industry accepted means of determining the optimum balance between on-going renewal and capex. The CBRM model calculates a Health Index (HI) and Probability of Failure (PoF) for each individual asset. This gives the asset a ranking which is used when determining a replacement strategy. While CBRM models calculate asset rankings, we use this information to prioritise our replacement schedule.

The CBRM process involves a number of sequential steps, as follows:

- define asset condition – HIs for individual assets are derived and built for different asset groups. Current HIs are measured on a scale of 0 to 10, where 0 indicates the best condition and 10 the worst
- link current condition to performance – HIs are calibrated against relative probability of failure. The HI / PoF relationship for an asset group is determined by matching the HI profile with the recent failure rate.
- estimate future condition and performance – knowledge of degradation processes is used to 'age' health indices. The ageing rate for an individual asset is dependent on its initial health index and operating conditions. Future failure rates can then be calculated from aged HI profiles and the previously defined HI / PoF relationship
- evaluate potential interventions in terms of PoF and failure rates – the effect of potential replacement, refurbishment or changes to maintenance regimes can then be modelled and the future health index profiles and failure rates modified accordingly
- define and weight consequences of failure (CoF) – a consistent framework is defined and populated in order to evaluate consequences in significant categories such as network performance, safety, financial, environmental, etc. The consequence categories are weighted to relate them to a common monetary unit
- build risk model – for an individual asset, its probability and consequences of failure are combined to quantify risk. The total risk associated with an asset group is then obtained by summing the risk of the individual assets
- evaluate potential interventions in terms of risk – the effect of potential replacement, refurbishment or changes to maintenance regimes can then be modelled to quantify the potential risk reduction associated with different strategies
- review and refine information and process – building and managing a risk-based process on the basis of asset specific information is not a one-off process. The initial application will deliver results based on available information and, crucially, identify opportunities for ongoing improvement that can be used to progressively build an improved asset information framework.

The following illustrates the CBRM HI approach.

Condition		Health Index	Remnant Life	Probability of Failure
Bad	10	🟥	At EOL (<5 years)	High
Poor		🟧	5-10 years	Medium
Fair		🟨	10-20 years	Low
Good	0	🟩	>20 years	Very low

The development of the CBRM models for Orion's assets was undertaken in two stages; an initial trial project (October 2010 – February 2011) followed by completion (March 2011 – October 2011). The models use specific location factors for Orion comprising:

- corrosion factors – defined by distance to coast
- damage from earthquakes – sourced from GIS map locations of cables which faulted following the earthquakes
- high water table – from ECAN water table information overlaid on GIS maps.

These three factors are believed to influence the likely performance of the assets located in our network area.

The modelling has generated HI profiles for all of our major asset categories. These are presented in the CBRM report for Year 0 and Year 10 – ie: they project the likely health of our assets in 10 years time. We are currently considering how to integrate this information into our asset replacement strategies. Our Asset Management Reports provide a description of the current HI information for each asset class and the potential implications of this for asset replacement.

Deliverability and prioritisation

Our planned replacement programme is expected to be able to be carried out with normal contracting arrangements. The scheduling of the work may be able to be altered to some extent to take into account any resource constraints which may arise due to other priorities or network load constraints. We prioritise work in accordance with our project prioritisation policy (NW70.60.14) which is described in Section 9.13.4 above.

We determine our replacement and maintenance priorities by following the general principle that the assets supplying the greatest number of consumers receive the highest priority. We extensively review areas of the network where scheduled asset replacement programmes occur to ensure the most efficient and cost-effective solution is sought to fit in with the current and long-term network development structure, for example replacement of switchgear in substations.

The risk with any type of replacement programme is that network switching or alternative supplies (generators) will be required to off-load the assets which are to be replaced. This leads to increased risk of outages and hence reduced reliability. We try to mitigate this by co-ordinating replacements with other work and where possible carry out the work at periods of lower network loading.

Documents, policies and consultants reports

The documents policies and planning standards relevant to our replacement capex category comprise:

- Asset management policy NW70.00.46
- Procurement policy OR00.00.19
- Contract management NW73.00.03
- Delegations of authority policy OR00.00.11
- Authorised contractors NW73.10.15
- Health and Safety policy OR00.00.01

- Environmental Sustainability Policy OR00.00.03
- Asset Lifecycle Management Reports for each asset class (NW70.00.22 – NW70.00.44)
- Application of CBRM with Orion New Zealand – EA Technology Report No. 76500 Issue 1 : March 2012

Their significance to our asset replacement programmes is summarised in Appendix 21.

Interaction with system growth projects

As noted above, where possible we co-ordinate our planned asset replacements with major projects such as substation upgrades. This is not a key driver however for the majority of our asset replacement programmes which are determined using the methods outlined above.

Relevance beyond the CPP regulatory period

All replacement programmes are ongoing. The long term plans are described in the asset management reports for each type of asset, which accompany this proposal. These address the asset lifecycle activities (maintenance and replacement).

Costing methods

The annual replacement programme is determined by our Infrastructure Lifecycle Manager and the Network Asset Manager in conjunction with the scheduled maintenance programmes for each asset category. A similar process has been adopted for the CPP forecasts, albeit without the benefit of annual review and refinement which is a normal part of our budgeting and planning process.

Our costing method is described in detail in Section 9.20.6 in relation to scheduled maintenance. The same costing methods apply and comprise the following key steps:

- forecast the quantum and nature of work to be undertaken on each asset category/type
- review contract prices for similar work undertaken over the past year and compare with MEA benchmarks, derived from recent replacement costs valuations and adjusted for input cost inflation where appropriate. These reflect market prices for our replacement and scheduled maintenance work. All such work over $20,000 is performed as a separate tendered contract and all work over $5,000 is undertaken only after obtaining at least two prices. In both instances the lowest conforming price is awarded provided the contractor conforms to the evaluation criteria. (Refer to our Contract Management Policies, listed in Section 9.5.1 of NW70.50.03)
- develop forecast budgets using the quantity of work to be performed and unit prices derived using the processes outlined above.

This method is described in NW70.60.15 – Asset Management Lifecycle Budget Forecasting Process.

9.15.1 Replacement – identified programmes

IM D7(2) (4) and (5)

Communications and protection

Our communications and protection replacement programme is included as an identified programme. The following information is provided in response to the requirements of D7(2). More extensive explanations are provided in our CPP33–Project Summary document.

Identified programme – CPP33 – communications and protection replacement capex

D7(2)	Explanation
(a) description including aims and objectives	The work undertaken in this programme involves replacement of our communication cables and terminations and protection systems. The assets included in this programme are: • Communication cables, terminations and distribution cabinets • Protection systems including: - Protection relays - Communication platforms - Ground fault neutralisers - Neutral earthing resistors - Current transformers - Voltage transformers The main objectives are public, contractor and staff safety, and replacement in order to maintain reliability and service levels. A further objective is effective cost management of assets and associated risks. The overall objective is to maintain asset health profiles consistent with current levels.
(b) deliverability	This replacement programme can be carried out within normal contracting arrangements. The scheduling of the work may be altered to some extent to take into account resource constraints and network loadings
(c) contingency factors	There are no contingency factors provided for in the capex programme
(d) assumptions, obligations and step changes	Like all companies we are subject to a number of obligations included in a wide range of legislation. Our main obligations are contained in our Statutory Compliance Manual. Our replacement programme assumes the following replacements:

Units	FY14	FY15	FY16	FY17	FY18	FY19	Avg Age
66kV Unit Protection (with intertrip)	4	0	2	2	2	3	41
Transformer Diff Protection and Control	2	2	1	1	1	1	23
Transformer Diff	0	0	0	0	0	1	11

	Protection and Control (+intertrip)							
	11/33kV Feeder Protection (with OC and EF)	0	1	1	0	1	2	22
	11/33kV Unit Protection	35	42	37	37	47	16	37
	11/33kV Unit Protection (with OC)	14	13	36	28	34	46	32
	11kV Protection (with OC & EF)I	27	39	46	49	64	34	32
	Bus Bar Protection Relay	4	2	2	6	0	3	20
	Directional Overcurrent Relay (with CB fail)	0	0	0	5	2	6	16
	11kV Protection (with OC, EF, reclose & CB fail)	7	7	7	0	4	12	25
	The underlying forecast assumes relays will be replaced in at least one and in some cases two zone substations each year. Generally assets are not replaced on age alone, but are kept in service until continued maintenance is uneconomic or they become a safety or environmental risk.							
(e) departures from consultants recommendations	There are no departures from consultants' recommendations in this capex programme. We note we are currently in the process of implementing the CBRM approach to asset replacement, and it is possible we could refine our programme in the future once we have had more opportunity to integrate EAT's CBRM models into our asset planning processes							
(f) forecasting methodology	The process used to forecast our replacement expenditure of protection relays has historically been directly linked to the replacement of switchgear. Usually both asset groups were installed at the same time and had similar lifecycles. With the introduction of the electronic relays (both analogue and digital) synchronisation of the lifecycles with switchgear is being lost. On some occasions a protection system will be upgraded due to the performance requirements of the network. Protection systems with known performance issues are given a higher priority for replacement. In some cases a number of relays less than 15 years old and even less than 10 years old may be scheduled for replacement even though the associated switchgear is not due to be replaced. In these cases the whole substations protection scheme is being upgraded to use fibre and merging units. We no longer replace like for like when doing a substation upgrade. Any units that haven't yet reached the end of their economic life will be reused elsewhere in the network or kept as spares. The project also includes amounts to upgrade the protection systems for the Transpower spur assets that we intend to acquire. There is also a small nominal							

	allowance for additional items such as Firmware upgrades and setting upgrades. This is explained in more detail in our Project Summary Document CPP33.
D(7)(5) Information beyond CPP period	This replacement programme will continue in perpetuity. Our communications and protection asset management reports included information to FY23 which coincides with the end of the planning period to be incorporated into our forthcoming 2013 AMP

Switchgear

Our switchgear replacement programme is included as an identified programme. The following information is provided in response to the requirements of D7(2). More extensive explanations are provided in our CPP36 – Project Summary document.

<table>
<tr><th colspan="2">Identified programme – CPP36 – switchgear replacement capex</th></tr>
<tr><th>D7(2)</th><th>Explanation</th></tr>
<tr><td>(a) description including aims and objectives</td><td>Replace on an annual basis high voltage and low voltage switchgear and high voltage circuit breakers for which it has been determined that replacement is the most cost effective way to ensure reliability of electricity supply and to meet service level targets (including safety). The work to be undertaken in this programme involves the replacement of switchgear assets that have reached the end of their economic lives as a result of a number of factors such as their condition, age, obsolescence, lack of spares, lack of support. The programme is closely related to the switchgear maintenance programme</td></tr>
<tr><td>(b) deliverability</td><td>This replacement programme can be carried out within normal contracting arrangements. The scheduling of the work may be altered to some extent to take into account resource constraints and network loadings</td></tr>
<tr><td>(c) contingency factors</td><td>There are no contingency factors provided for in the capex programme</td></tr>
<tr><td>(d) assumptions, obligations and step changes</td><td>Like all companies we are subject to a number of obligations included in a wide range of legislation. Our main obligations are contained in our Statutory Compliance Manual.
Our replacement programme assumes the following replacements:
<table>
<tr><th>Units</th><th>FY14</th><th>FY15</th><th>FY16</th><th>FY17</th><th>FY18</th><th>FY19</th><th>Average age</th></tr>
<tr><td>66/33kV switchgear</td><td>0</td><td>3</td><td>0</td><td>0</td><td>0</td><td>0</td><td></td></tr>
<tr><td>Spur asset CB (excludes Islington)</td><td>2</td><td>2</td><td>2</td><td>2</td><td>2</td><td>2</td><td></td></tr>
<tr><td>11kV Zone CB</td><td>19</td><td>15</td><td>53</td><td>0</td><td>35</td><td>52</td><td>49</td></tr>
<tr><td>11kV Network CB</td><td>60</td><td>52</td><td>27</td><td>57</td><td>52</td><td>37</td><td>48</td></tr>
<tr><td>11 kV MSU</td><td>2</td><td>23</td><td>42</td><td>140</td><td>34</td><td>71</td><td>49</td></tr>
<tr><td>11kV Fuse Switch</td><td>17</td><td>10</td><td>11</td><td>0</td><td>8</td><td>0</td><td>47</td></tr>
</table></td></tr>
</table>

11kV OIS	0	6	2	0	0	0	39
Urban LV	80	80	80	80	80	80	
Rural LV	55	55	55	55	55	55	
ABIs	35	35	35	35	35	35	
Addington 11kV	0	8	0	0	0	0	

	With the exception of FY17, the total cost of these scheduled replacements remains relatively constant in real terms. This has been a factor in determining how these replacements are scheduled. . In FY 17 a larger number of MSUs are programmed to be replaced as we were not planning to carry out any 11kV zone substation circuit breaker replacements in that year. This increase was made because they are approaching the end of their expected lifecycle. Large numbers of these units were installed in approximately 1960 when the use of oil based switchgear started to decline. Since that time the acquisition of Transpower spur assets and the need to replace a number of 33kV circuit breakers at Islington has required a forecast allowance for their replacement to be included in FY17.
(e) departures from consultants recommendations	There are no departures from consultants' recommendations in this capex programme. We note we are currently in the process of implementing the CBRM approach to asset replacement, and it is possible we could refine our programme in the future once we have had more opportunity to integrate EAT's CBRM models into our asset planning processes
(f) forecasting methodology	The costs for this capex programme are derived based on a brown-fields basis using costs for replacement of like with like switchgear. These FY08 values have been inflated by 8% in FY13. These are projected forward consistent with our cost escalation approach which is described in Section 9.26 below. Our construction cost benchmarks (included in Appendix 27) show that our 2010 switchgear costs were on or below the industry average for all but one switch type.
D(7)(5) Information beyond CPP period	This replacement programme will continue in perpetuity. Our switchgear asset management reports included information to FY23 which coincides with the end of the planning period to be incorporated into our forthcoming 2013 AMP

Transformers

Our transformer replacement programme is included as an identified programme. The following information is provided in response to the requirements of D7(2). More extensive explanations are provided in our CPP37 – Project Summary document.

Identified programme – CPP37 – transformer replacement capex

D7(2)	Explanation
(a) description including aims and objectives	The assets included in this programme include 11kV oil filled voltage regulators, power transformers and distribution transformers. Within the CPP period, no power transformers are forecast to be replaced.

<table>
<tr><td></td><td>When a distribution transformer maximum demand exceeds 130% of its nameplate rating a larger transformer is installed or load is transferred to another substation if available. If utilisation is low, a transformer may be changed or removed.
Our aims are to ensure safety of public, contractors and staff. In addition we wish to maintain reliability in a cost effective way. Typically we do this by:
running small transformers with low loads to failure
replace pole mounted transformers in conjunction with line renewals
replace larger transformers, serving more customers, before they fail.</td></tr>
<tr><td>(b) deliverability</td><td>This replacement programme can be carried out within normal contracting arrangements. The scheduling of the work may be altered to some extent to take into account resource constraints and network loadings</td></tr>
<tr><td>(c) contingency factors</td><td>There are no contingency factors provided for in the capex programme</td></tr>
<tr><td>(d) assumptions, obligations and step changes</td><td>Like all companies we are subject to a number of obligations included in a wide range of legislation. Our main obligations are contained in our Statutory Compliance Manual.
Our replacement programme assumes a step change from FY13 with an increase in transformer replacements due to more transformers reaching advanced ages, particularly the larger transformers (which are more expensive to replace). One voltage regulator is to be replaced in FY14.
<table>
<tr><th>Quantity</th><th>FY13</th><th>FY14</th><th>FY15</th><th>FY16</th><th>FY17</th><th>FY18</th><th>FY19</th></tr>
<tr><td>Small transformers</td><td>110</td><td>115</td><td>125</td><td>125</td><td>125</td><td>125</td><td>125</td></tr>
<tr><td>Large transformers</td><td>80</td><td>120</td><td>120</td><td>120</td><td>120</td><td>100</td><td>100</td></tr>
<tr><td>Voltage regulator</td><td></td><td>1</td><td></td><td></td><td></td><td></td><td></td></tr>
</table>
As we don’t know exactly which transformers will be scheduled into each annual replacement programme we are currently estimating that 50% the annual budget will be assigned to each of pole (small) and pad (large) mounted transformers. Note the unit costs are higher for the larger transformers, hence the budget allocation differs to the quantity estimates.</td></tr>
<tr><td>(e) departures from consultants recommendations</td><td>There are no departures from consultants’ recommendations in this capex programme. We note we are currently in the process of implementing the CBRM approach to asset replacement, and it is possible we could refine our programme in the future once we have had more opportunity to integrate EAT’s CBRM models into our asset planning processes.</td></tr>
<tr><td>(f) forecasting methodology</td><td>Our replacement programme is predominantly age based. It will be informed to a greater degree in the future by the CBRM models. As a significant proportion of transformers were installed in the 1960’s, we are starting to see an increase in assets reaching the end of their expected lives, which is supported by increasing failure rates. More detail is included in our CPP37 Project Summary Document.</td></tr>
<tr><td>D(7)(5) Information</td><td>This replacement programme will continue in perpetuity. Our transformer asset management reports included information to FY23 which coincides with the end of</td></tr>
</table>

beyond CPP period	the planning period to be incorporated into our forthcoming 2013 AMP

9.15.2 Replacement – other programmes

IM D7 (6)

Explanations for all other replacement programmes are included in their Project Summary documents. A full list of these is set out below. Unless stated otherwise, all programmes are expected to continue in perpetuity.

Replacement programmes (not included as an identified project)

Reference	Project Name	Description of assets included in replacement programme
CPP30	Overhead lines sub transmission	The overhead subtransmission network is primarily made up of 33kV pole lines and 66kV pole/tower lines. These lines are built using timber, concrete and steel poles and steel towers with a range of conductor and foundation types.
CPP31	Overhead lines 11kV and 400V	The assets included in this replacement programme comprise approximately 6300 km circuit length of lines operating at 11kV, 400V or 230V. This is made up of: • Poles (softwood, hardwood, concrete, steel) • Crossarms (hardwood, steel) • Insulators (glass, porcelain, polymer) • Conductors (aluminium, copper)
CPP41	Underground cables sub transmission	Includes 66kV self contained oil-filled 3 core aluminium cables and XLPE single core copper cables and 33kV PILCA and XLPE cables
CPP32	Underground cables 11kV and 400V	The assets that are included in this programme are 11kV and 400V underground cables and distribution hardware. These include: • 11kV, 400V cable (cross-linked polyethylene (XLPE) single core copper, paper insulated lead cable armour (PILCA) grease-filled copper, PILCA grease-filled aluminium, XLPE single core aluminium • PVC 400V cable (copper, aluminium) • Distribution cabinets (also known as link boxes) • Distribution boxes (also known as boundary boxes)
CPP34	Control systems	The assets that are included in this programme are our communication systems and distribution management system (DMS). These include: • Communication Systems - Voice communications systems - Data communications systems (including SCADA) • DMS - a collection of applications designed to monitor and control the distribution network efficiently and reliably. It acts as a decision support system to assist the system control operators and field operating personnel with monitoring and control of the electricity distribution system. Improving the reliability and quality of service in terms of reducing and minimising outage time, maintaining acceptable frequency and voltage levels are the

		key deliverables of a DMS. DMS includes: - Network model - Remote terminal units - SCADA master station - DMS applications (outage management system, mobile despatch, historian, real-time load flow analysis, information interfaces with consumers)
CPP38	Substations	Includes 66/11kV zone substations, 33/11kV zone substations, 11kV zone substations, network substations and distribution substations (but does not include the transformers, switchgear, protections and control equipment housed within these substations)
CPP39	Buildings and grounds	This programme covers the buildings and grounds associated with our zone, network, distribution buildings and distribution kiosks
CPP40	Meters	Includes high voltage (11kV) consumer metering, Transpower GXP metering, power quality measurement metering and monitoring equipment and maximum demand ammeters
CPP35	Load management systems	Includes Orion's load management master station and RTUs, upper South Island load management system, ripple injection system and communications
CPP42	Asset management system	Our Asset Management Systems hold information about the equipment that comprises the electricity network and support business processes that build and maintain that equipment. The majority of our primary asset information is held in our asset register, GIS system and cable databases. We hold information about our network equipment from GXP connections down to individual LV pole level with a high level of accuracy. In addition to these asset registers we also hold detailed information regarding customer connections in a Connections Register and track the process of asset creation and maintenance in Works Management. Key assets included are : • Geographic Information System • Asset Register • Cable databases • Works management and enquiry for supply • Connections register
CPP43	Distribution management system	A DMS is a collection of applications designed to monitor and control the entire distribution network efficiently and reliably. It acts as a decision support system to assist the system control operators and field operating personnel with monitoring and control of the electricity distribution system. Improving the reliability and quality of service in terms of reducing and minimising outage time, maintaining acceptable frequency and voltage levels are the key deliverables of a DMS. The key assets include: • Network model • Remote terminal units • SCADA master station • DMS applications - Outage management system

- Mobile despatch
- Historian
- Real-time load flow analysis
- Information interfaces to the business and connected customers

Appendix 21 also explains which of our policy documents are relevant to the replacement capex programmes.

Our costing method for replacement programmes is described in Section 9.15 above.

In addition, as stated earlier, there are no contingency factors provided for within the replacement capex programme.

9.16 Other network capex

Aims and objectives

Our other network capex comprises expenditure on underground conversions and network connections and extensions. The primary objective for this capex is to meet the needs of consumers or external agencies such as NZTA.

Key features

Our other network capex is made up of the following programmes:

Capex – Other network				
Reference	**Project Name**	**Nominal value over next period ($m)**	**Nominal value of external contributions over next period ($m)**	**Identified project**
CPP50	Underground conversions	24.8	14.4	Yes
CPP53	Connections and extensions	93.0	11.3	Yes

As both of these projects are identified projects, they are described in some detail in the following section.

Documents, policies and consultants reports

The documents, policies and planning standards relevant to our conversion and extension capex projects comprise:

The undergrounding and connection and extension work is very similar to network reinforcement. New assets will be installed according to Orion's design standards, technical specifications and policies as summarised in NW 70.50.03 – Document Control. In particular for these capex categories they will be implemented in compliance with the policies set out in the following sections:

- 9.2 Infrastructure
    - 9.2.1 Management
    - 9.2.3 Design Standards
    - 9.2.4 Technical Specifications
- 9.5 Contracts
    - 9.5.1 Management
- 9.7 Procurement & Stock Management
    - 9.7.2 Equipment Specifications

Their relevance to non-network capex is summarised in Appendix 21.

Connections and extensions policy (NW70.00.45)

When an application for a new or upgraded connection (larger connections only) is submitted for review, we undertake an economic assessment of the connection. This assessment determines whether or not our standard pricing arrangements will cover the cost of utilising existing or new assets associated with the connection. If the connection is uneconomic (i.e. existing consumers would be subsidising the new connection) then a connection contribution is required from the new consumer. This connection contribution eliminates the need to increase prices to existing consumers.

This policy ensures that the true cost of providing supply is passed on to the appropriate consumer and thereby allows them to make the right financial trade-offs. If an economic non-network alternative is available then that option can be chosen by the consumer.

Underground conversions policy (NW70.00.10)

This policy sets out the approach to funding underground conversions. Costs are generally apportioned in the following ways:

- Orion pays 18.7% of the cost of discretionary underground conversion including services. The decision to proceed with these enhancement projects is the local Authority's
- individuals can decide to underground their mains at their cost. In some cases Orion may decide to supplement this cost where there is an identified justifiable benefit
- recovery of costs from NZTA and other roading authorities are set out in section 6 of the National Code of Practice for Utility Operators to Transport Corridors (October 2011). This specifies guidelines for cost allocation and references the underpinning legislation (for electricity it is predominantly the Electricity Act, sections 24A, 33 and 34.

Relevance beyond the CPP regulatory period

These activities will extend beyond the end of the CPP regulatory period. They are initiated by third parties, and we will respond as appropriate, consistent with the assumptions we have made for the CPP regulatory period.

Costing methods

The costs for these projects are derived using the same method as for our major project capex – described in Section 9.13.11, escalated in accordance with our method described in Section 9.26.

In addition, as stated earlier, there are no contingency factors provided for within these projects.

Deliverability

Connection and undergrounding work uses similar contracting resources as 11kV reinforcement. It is managed as part of the contracting workflow. Where possible connection, extension or undergrounding work is co-ordinated with reinforcement projects and other civil works such as roading, water and telecommunications, especially in new subdivisions.

9.16.1 Other network capex – identified programmes

Identified programme – (CPP 50) underground conversions	
D7(2)	**Explanation**
(a) description including aims and objectives	The Christchurch City Council policy via the City Plan is for all new reticulation in the urban area to be underground. Converting overhead reticulation to cable cannot be justified on an economic basis alone and there is no programme to systematically remove all overhead assets from the urban network. When reinforcement or replacement takes place in built-up areas, associated overhead assets (especially 11kV) will normally be undergrounded as part of the works where practical and the costs of this work (over and above the installation of new capacity) are provided from this budget. In addition, underground conversion takes place in the following circumstances: • as required by NZTA or local councils as part of roading upgrades • as required by local councils as part of neighbourhood planning and improvements • at the request of private individuals or property developers.
(b) deliverability	In these cases, our costs are partially or totally subsidised by the other party.
	Underground conversions use the same contracting resource as reinforcement and connection and extension work. Because work plans are usually determined by external requirements we have less flexibility than for those projects initiated by Orion. Schedules are known well in advance however, which assists with efficient planning and there is a good depth of contracting resource for this type of work in Canterbury.
(c) contingency factors	There are no contingency factors provided for in this capex programme
(d) assumptions, obligations and step changes and (f) forecasting methodology	Over the CPP period, several major NZTA projects involving new motorways and widening of existing roads will result in the removal of many kilometres of overhead reticulation. Developer-initiated undergrounding of some 66kV assets is also expected. Both CCC and Selwyn District Council (SDC) allocate funds annually for undergrounding works.

Underground conversions are not driven by network constraints or reinforcement requirements, although load forecasting will be taken into account in selecting conductor size to avoid unnecessary future constraints. Reliability is improved so the effect on service targets is positive.

Our project spend (in real terms) by source is set out below. Of this, approximately 60% is expected to be funded by external parties.

(Real $m)	FY13	FY14	FY15	FY16	FY17	FY18	FY19
NZTA	1.9	1.7	0.4	4.4	2.2	0.2	0.2
Council Initiated	0.4	0.6	0.6	0.6	0.6	0.6	0.6
Private Developer	0.0	3.3	0.0	0.0	0.0	0.0	0.0
CBD	0.0	0.5	0.5	0.5	0.5	0.5	0.0

Our council shareholders have agreed that it is their responsibility to determine the priority for discretionary undergrounding projects and to pay for such work on an agreed basis. This is a commercially sound arrangement which puts the correct incentives on the parties and one which is appropriate for both shareholders and Orion. In addition:

- we underground most urban extensions to our network, although this policy is being reviewed post earthquakes
- in rural areas it is often up to the developer to decide whether reticulation is underground or above ground
- a portion of our system reinforcement, safety and improvement projects will continue to include undergrounding of overhead reticulation

(e) departures from consultants recommendations	There are no departures from consultants' recommendations in this capex programme.

More extensive explanations are provided in our CPP50 Project Summary document.

Identified programme – (CPP 53) connections and extensions

D7(2)	**Explanation**
(a) description including aims and objectives	As potential customers apply to be supplied by the Orion network, work is required to connect them. Where the connection is not directly adjacent to existing assets or there are multiple connections (e.g. residential subdivisions) then new infrastructure is needed to extend the network. If the capacity of the existing sub transmission and backbone 11kV network is sufficient to provide for the new load with the appropriate security of supply, then the new assets come entirely from this project budget. If not, then separate investment in the existing network is made from the Urban and/or Rural Reinforcement budgets. The cost of any reinforcement required to upgrade the low voltage 400V network to connect new customers however is included in this budget. The work mostly involves the installation of 11kV and low voltage overhead

<table>
<tr><td></td><td colspan="8">conductors and pole substations (rural areas), and 11kV and low voltage cable, ground-mounted transformers and switchgear housed in kiosks (urban areas). Streetlighting assets are included in new subdivisions.
Consumers seeking new connections contribute to the costs of this activity in accordance with our connections and extensions policy NW70.00.45.</td></tr>
<tr><td>(b) deliverability</td><td colspan="8">11kV connection works use the same contracting resource as reinforcement and undergrounding work and are managed as part of the contracting workflow. LV works have a wider pool of contracting businesses available. Connection work is by nature customer related and as such has a high priority. Our project prioritisation approach is described in Section 9.13.4 above.</td></tr>
<tr><td>(c) contingency factors</td><td colspan="8">There are no contingency factors provided for in this capex programme</td></tr>
<tr><td rowspan="8">(d) assumptions, obligations and step changes
(f) forecasting methodology</td><td colspan="8">The earthquakes have introduced changes to economic activity and growth in Canterbury, and forced the relocation of existing residential and commercial customers. The relocation of businesses to the Addington/Airport area and the increasing residential development in the north-east, Rolleston and west of Christchurch is expected to increase connection and extension demand. Accordingly the expected trend in connections work is to exceed the recent average for the next few years.
Our project spend (in real terms) by source is set out below. Of this, approximately 13% is expected to be funded by external parties.</td></tr>
<tr><td>(Real $m)</td><td>FY13</td><td>FY14</td><td>FY15</td><td>FY16</td><td>FY17</td><td>FY18</td><td>FY19</td></tr>
<tr><td>Urban connections</td><td>2.1</td><td>3.4</td><td>3.4</td><td>3.4</td><td>3.2</td><td>3.0</td><td>2.4</td></tr>
<tr><td>Rural connections</td><td>0.1</td><td>0.2</td><td>0.2</td><td>0.2</td><td>0.2</td><td>0.2</td><td>0.2</td></tr>
<tr><td>Subdivisions</td><td>5.3</td><td>5.3</td><td>5.3</td><td>5.3</td><td>4.4</td><td>3.8</td><td>3.8</td></tr>
<tr><td>Switchgear</td><td>0.7</td><td>1.0</td><td>2.2</td><td>2.5</td><td>2.5</td><td>2.3</td><td>2.3</td></tr>
<tr><td>Transformers</td><td>1.4</td><td>2.0</td><td>2.0</td><td>2.0</td><td>2.0</td><td>1.8</td><td>1.8</td></tr>
<tr><td>Other</td><td>0.1</td><td>0.1</td><td>0.1</td><td>0.1</td><td>0.1</td><td>0.1</td><td>0.1</td></tr>
<tr><td>(e) departures from consultants recommendations</td><td colspan="8">There are no departures from consultants’ recommendations in this capex programme.</td></tr>
</table>

9.17 Non network capex

IM D11

Aims and objectives

The aims and objectives of non system capex are to provide the support infrastructure necessary to ensure we are able to meet our service obligations which are primarily delivered by our network assets.

Key features

Our non-network capex programme is comprised of the following projects

Capex – Non network			
Reference	**Name**	**Nominal value over next period ($m)**	**Two largest categories**
CPP60	New head office	19.5	Yes
CPP62	Sundry land and buildings	2.2	
CPP63	Vehicles and mobile plant	5.8	
CPP64	Information technology	11.0	Yes
CPP65	Sundry tools, equipment, furniture and fittings	4.4	

Documents, policies and consultants reports

The documents, policies and standards relevant to our non-network capex categories comprise:

- Procurement policy OR00.00.19
- Contract management NW73.00.03
- Delegations of authority policy OR00.00.11
- Authorised contractors NW73.10.15
- Health and Safety policy OR00.00.01
- Environmental Sustainability Policy OR00.00.03

Their significance to non-network capex is summarised in Appendix 21.

Deliverability

Deliverability is not generally an issue for non-network capex as it primarily involves asset purchases, rather than construction activities. The principal one-off exception is the construction of our new head office, however we do not believe that this project is an issue because construction is well underway, with an expected completion date of June 2013.

9.17.1 Non-network capex – largest two categories

In accordance with Schedule D11 we have set out below our rationale for our planned expenditure associated with the largest two capex categories, by value.

Non-network capex – largest two categories	
D11	**Explanation**
CPP 60 and CPP 62 Office buildings, depots and workshops	The project is dominated by the construction of a new head office site in FY13. This is required because our previous head office has been demolished as a result of earthquake damage. We are currently operating from temporary buildings on that site. Our current operations centre at 200 Armagh Street is an IL2 building which is below the requirement in the Civil Defence Emergency Management Act for a 'lifeline utility'. It is also insufficient for our needs as it is considerably smaller than our original office, and we have many functions operating from within porta-cabins as an interim measure. Our new head office will increase the resiliency of our operations, by moving to a new Importance Level 4 (IL4) standard building. This will enable compliance with Civil Defence Emergency Management (CDEM) Act requirements Relocating to a new head office site is also required because CERA wishes to purchase the land we currently operate from as part of CERA's 'priority one' CBD recovery plan. This project has already been committed and tendered for. The project is expected to be completed in June 2013. Our project costs are comprised of: • land purchase in FY13 • building cost as per construction contract (FY13 and FY14) • indicative tender price for loose furniture • consultant fees of 5% on build and furniture cost • further adjacent land purchase in FY14 Minor other building related capex is provided for each year, based on historical costs and is required in order to ensure that our non-network buildings continue to meet our needs and are safe for our employees and contractors to work in.
CPP64 Information technology	This programme includes expenditure on our maintenance agreement for information systems. 80% of licensing agreements are attributed to capital because they are considered to represent prepayment for upgrades. Our forecast includes our document management project which will be implemented in three phases that will be complete by FY15. Other expenditure includes business-as-usual purchases of IT support for employees, replacement of damaged equipment (in particular during FY13 as a result of the earthquakes) and incremental improvements. There is also a number of one off expenditure items, including an upgrade of our second computer facility in FY14 and a capacity upgrade to our Virtual Server environment (CPU and storage) in FY16. In FY18 it is expected that there will be an upgrade of the physical servers and client devices. Telephony expenditure throughout this period includes all expenditure on mobile phones, which have a lifecycle of two years and our Nortel/Avaya telephone switch. There is significant expenditure expected to be incurred in FY16 due to an upgrade of equipment. The Central Government Contract for Computing establishes a single supply agreement between the Crown and suppliers for certain goods. Orion is able to

purchase most or all of our computer equipment under this contract. The prices from this agreement are significantly lower than what we could obtain through standard tender processes.

These projects, along with other non-network capex projects, are each summarised in separate Project Summary documents, which set out the rationale and basis for the project expenditure forecasts. The Project Summary Documents for CPP60, CPP62 and CPP64 support this proposal.

9.18 Opex forecast

IM D12

Our opex forecasts comprise:

- emergency maintenance
- scheduled maintenance
- non-scheduled maintenance
- network management and operations opex
- general management, administration and overheads opex (referred to as corporate opex).

Each of these is addressed below. Schedule D of the CPP IMs includes specific information requirements for categories of opex. As we are using our own opex categories, which are similar to but not exactly the same as those included in Schedule D (for the reasons we described earlier in Section 8.5.3), we have addressed the information requirements as follows:

Meeting Schedule D requirements for opex

Schedule D reference	Targeted requirements	CPP proposal Section 9 reference	Component of Orion's capex plan
D12	Minimum requirements for all opex categories	9.19 – 9.23	Addressed in each section (by opex category)
D13	General management, administration and overheads opex	9.23	General management, administration and overheads opex
D14	Minimum requirements for all non identified opex projects and programmes	9.19 – 9.23	Addressed in each section (by opex category)
D15	Self insurance	9.23	General management, administration and overheads opex

D11	Controllable opex	9.24	Controllable opex

A more detailed compliance summary is set out above in Section 9.2.1. We have set out the remainder of the discussion about our opex forecasts in a format which is consistent with the information requirements of Schedule D.

9.19 Emergency maintenance

9.19.1 Aims and objectives

Emergency maintenance responds to unplanned events that impair the normal operation of network assets. The aim of this opex is to undertake the work as quickly as possible after the occurrence of an unexpected event in order to bring the distribution network back to at least its minimum acceptable and safe operating condition. This opex category has direct links to our reliability targets set out in Section 9.6 above.

9.19.2 Key features

Our emergency maintenance has required unprecedented levels of expenditure in FY11 and FY12 as we have responded to the impacts of the earthquakes on our network.

The disruption to our network and our response to that disruption is explained in some detail in Sections 3.2 to 3.3 and 6.2 to 6.3 of this proposal.

Our forecasts contain much lower levels of emergency maintenance expenditure and we have not included any allowances for further catastrophic events in this CPP proposal. However, we forecast higher levels of failure than we experienced before the earthquakes during this recovery phase. Our network assets are not as resilient as they were and there are more third party impacts on our network as part of the rebuilding process. The key components of our forecast emergency maintenance programme for the next period (FY13 – FY19) are summarised below. We have also included our actual spend for FY11 and FY12 for comparison purposes.

Opex – Emergency maintenance

Reference	Name	Nominal value over next period FY13-FY19 ($m)	FY11 and FY12 nominal actual spend ($m)	Identified programme
CPP117	Overhead lines	16.6	4.9	
CPP118	Underground cables	26.3	20.7	Yes
CPP119	Network assets	10.7	9.5	Yes

9.19.3 Deliverability and prioritisation

All of our maintenance programmes are developed to ensure the safety of the public and our personnel around our assets. We also aim to strike a balance between cost and quality of supply to our consumers. Our priorities for emergency works are driven by the needs of our consumers, in particular our network reliability performance and minimising the outages experienced by our consumers consistent with their requirements. Our proposed quality standards, described in Section 6 of this CPP proposal, explain our expected reliability performance for the CPP period. Our emergency maintenance programmes are consistent with this.

Emergency works contracts

Our emergency works are delivered primarily under two emergency works contracts. We had defined emergency response (works) and non-scheduled (minor works) contracts in place with Connetics and Independent Lines Services (ILS) for many years. These have recently been renegotiated. The previous contracts were negotiated in 2006 and were due to expire March 2011. However, due to the earthquakes they were extended until the new contracts could be formalised, which occurred in October 2012. The new contracts have a three year term (expiring on 30 September 2015), with a possible two year extension, subject to satisfactory performance reviews.

We have two emergency response contractors. These contractors have defined response areas within their contracts. ILS provides our full emergency response service in the high country and plains areas and a portion of the Banks Peninsula area (covering all overhead reticulation and low voltage cable response). Connetics services the balance of our network.

When a fault on the network occurs, our Control Group dispatches the emergency response contractor responsible for the network area concerned. The contractor then remedies the fault and makes the network safe again.

The Emergency Works Technical Specification NW72.20.03 defines what is classed as routine and non-routine plant repairs and certain estimated values of work that the contractor is authorised to respond to. When the repair works is non routine or above a certain estimated value, our Contract Manager is engaged to assist the contractor devise a repair strategy and provide the authorisation for the works to occur.

Each contract includes scheduled rates for labour and plant. When a contractor tenders for emergency response or non-scheduled contracts, they propose their scheduled rates. Our evaluation of the proposed rates compares them against previously benchmarked rates for the same types of labour and plant response works and the previous contract rates with appropriate cost escalation factors derived from NZS3910:2003 (Appendix A which sets out relevant Statistics NZ labour and materials indices).

The escalated old rates and benchmark information provide us with information about the percentage increases/decreases (in some instances) proposed by the contractor. These rates are clarified, with due diligence if necessary, and accepted or re-negotiated as appropriate.

Our emergency contractors are an essential part of our overall resiliency under the CDEM Act. If our key contractors are unable to operate in an emergency, then it will seriously undermine our own ability to respond.

Our emergency works contracts now contain new resiliency criteria that require our contractors to meet our obligations under the CDEM Act. Risk reviews have been undertaken by the contractors to determine their susceptibility to future events. The costs incurred to mitigate these issues have been apportioned across each of our asset classes.

Emergency spares

Orion holds emergency spares to reduce potential outage times in the event of a fault. These spares are stored at Connetics and are readily available when required. The number of spares kept is assessed based on a risk assessment and required response.

9.19.4 Documents, policies and consultants' reports

The documents, policies and planning standards relevant to our emergency maintenance opex comprise:

- Asset management policy NW70.00.46
- Procurement policy OR00.00.19
- Contract management NW73.00.03
- Delegations of authority policy OR00.00.11
- Authorised contractors NW73.10.15
- Health and safety policy OR00.00.01
- Environmental sustainability policy OR00.00.03
- Emergency works NW72.20.03
- Asset Lifecycle Management Reports for each asset class (NW70.00.22 – NW70.00.44)

A number of our Network Operation operating management policies, standards, procedures and instructions are relevant to emergency maintenance. These are set out in Section 9.3 of NW70.50.03.

All of the above documents' relevance to our emergency maintenance programme is summarised in Appendix 21.

9.19.5 Emergency maintenance – identified programmes

Our emergency maintenance programme for underground cables is included as an identified programme. The following information is provided in response to the requirements of CPP IM D12 (2)-(5). More extensive explanations are provided in our CPP118 Project Summary documents provided as support to this proposal and the associated asset lifecycle management reports (NW70.00.30-32).

Identified programme CPP118 – emergency maintenance opex – underground cables	
D12(2) – (5)	**Explanation**
(2)(a)(i) description	Emergency maintenance responds to unplanned events that impair the normal operation of our cables. The aim of this opex is to undertake cable repairs as

<table>
<tr><td>including aims and objectives</td><td>quickly as possible after unplanned outages in order to bring our distribution network back to at least its minimum acceptable and safe operating condition.
The September 2010 and February 2011 earthquakes caused over 800 cable faults at 66kV and 11kV levels. They were mainly confined to areas subjected to large lateral movement of the ground in Brighton, Dallington and Avondale. The earthquake in June 2011 caused some further damage to our cables. However, it was limited to areas that were already damaged in February.
We anticipate that cables that have been subjected to stresses caused by the earthquakes will have higher failure rates in the next few years because of compromised cable sheaths and insulation. To mitigate this we have a rigorous maintenance programme scheduled to test our cables in identified areas over the coming years to determine whether maintenance or replacement is required.</td></tr>
<tr><td>(2)(a)(ii) deliverability</td><td>This emergency maintenance programme will be carried out under our emergency contracts, which have been let to Connetics and ILS until 2015, with possible renewal for another two years.</td></tr>
<tr><td>(2)(a)(iii) contingency factors</td><td>There are no contingency factors provided for in this emergency maintenance programme</td></tr>
<tr><td>(2)(b) and (5) assumptions, obligations and step changes</td><td>We are subject to a number of obligations included in a wide range of legislation. Our main obligations are contained in our Statutory Compliance Manual. Of particular relevance to emergency maintenance are health and safety and civil defence requirements. Our emergency cable programme includes the following allowances:
<table>
<tr><th>$m (real)</th><th>FY13</th><th>FY14</th><th>FY15</th><th>FY16</th><th>FY17</th><th>FY18</th><th>FY19</th></tr>
<tr><td>66kV</td><td>0.1</td><td>0.1</td><td>0.1</td><td>0.1</td><td>0.1</td><td>0.1</td><td>0.1</td></tr>
<tr><td>33kV</td><td>0.0</td><td>0.1</td><td>0.1</td><td>0.1</td><td>0.1</td><td>0.1</td><td>0.1</td></tr>
<tr><td>11kV</td><td>1.2</td><td>1.6</td><td>1.6</td><td>2.0</td><td>1.6</td><td>1.6</td><td>1.6</td></tr>
<tr><td>400V</td><td>1.1</td><td>1.4</td><td>1.4</td><td>1.7</td><td>1.4</td><td>1.4</td><td>1.4</td></tr>
</table>
These figures include amounts to improve resiliency for stores management. This includes reviewing current status and ensuring we can address issues which arise. In FY16 our stores and spares will be moved to a new lifelines standard building managed by Connetics. We have allocated the costs of this move across all asset categories in their emergency maintenance budgets in FY16.

Prior to the earthquake, the majority of our cable faults were caused by:
• third party damage
• damage of cable during installation or other disturbance causing premature failure.

To manage these faults we have:
• proactively promoted cable locating services to contractors
• inspected contractors during cable laying
• required all new cable to have an orange coloured sheath to allow easier</td></tr>
</table>

	identification. We measure the performance of our cables based on many different benchmarks such as SAIDI, SAIFI and fault incident records. In respect of 66kV cables, our failure modes have included, in addition to the above: • terminations issues such as oil leaks • differential ground settlement that can occur as a result of poorly compacted fill material or naturally soft ground for example organic clays and peat • movement as a result of an earthquake as recently observed. Our 66kV cable routes have been assessed to ascertain their vulnerability to a seismic event. To manage all possible risks we are currently developing strategies for where new cables in the eastern suburbs should be run and what bridges need to be reinforced for river crossings. The average age of our 33kV cables is 20 years. In the past decade, most of the emergency repairs revolved around fixing leaky oil-filled cable joints or rectifying oil pressure issues. All of these oil based issues are now behind us with the removal of the oil-filled cables and the adoption of XLPE cable. The 33kV cables and joints performed well throughout the earthquakes with no major failure or replacement needed. However, a maintenance schedule is planned to take place over the coming years to ensure the integrity of all the cables has not been compromised and there is no evidence of any accelerated deterioration. The average age of the 11kV underground network is approximately 30 years old. The overall condition of these cables is good, however we are expecting an increase in the failure rates for cables in the eastern suburbs. The majority of our 11kV cables that failed during the earthquakes were of a PILCA type, having been installed for an average of 40-50 years. Some of these cables had multiple faults. The failure modes were either joints (typically older pitch filled) being pulled apart or significant movement of the cables causing the deformation and failure of the cables outer membrane/lead and subsequently the paper insulation. We have developed a programme to test the cables in this area to determine if the expected life of these assets has been affected. The earthquakes also damaged our 400V cables for the same reasons outlined above. Like 11kV cables, we expect an increase in 400V cables failures, particularly in the eastern suburbs.
(2)(c) and (3) forecasting methodology	There are no departures from consultants' recommendations in this opex programme. We note we currently have a cable testing programme underway, which may require us to refine our expenditure estimates in the future. Our costs are derived consistent with our emergency contracts. The contract prices will be escalated over the CPP regulatory period. Our escalation method for the CPP forecast is described in Section 9.26 Our proposed quality standards, described in Section 6 of this proposal, explain our expected reliability performance for our cables during the CPP period. Our emergency maintenance programmes are consistent with this. This emergency works programme is directly relevant to our network

	performance, network restoration and customer service measures outlined in Section 9.6. Without this expenditure we would not be able to deliver the SAIDI and SAIFI targets we have proposed for the CPP regulatory period. It also has indirect linkages to our health and safety and environmental service targets, which reach across our entire operation.
(4) relevant policies	Our emergency works contracts are specified consistent with the following policies: • Procurement Policy OR00.00.19 and Contract Management NW73.00.0 – we follow our procurement and contract management policies to achieve value for money by competitively tendering our work with a value over $20,000. • Delegations of Authority Policy OR00.00.11 – the overall budgeted expenditure for this programme is approved by the Board as part of the overall Asset Management Plan. The actual expenditure is then approved as and when incurred, in compliance with the delegations of authority policy • Authorised Contractors NW73.10.15 – we ensure only authorised contactors are allowed access to our network • Health and Safety Policy OR00.00.01 – we follow our health and safety requirements to ensure the safety of the public and our personnel and contractors around our assets • Network operating standards, procedures and instructions (generally those policies designated NW20, NW21 and NW72.13) determine how our contractors work around our network assets during emergency maintenance and how they interface with our operators • Emergency Works Contract Management (NW72.20.03) sets out the terms and duties of our emergency works contractors • Spares are covered by procurement and stock management policies (generally those designated NW72.20)

Our emergency maintenance programme for network assets is included as an identified programme. The following information is provided in response to the requirements of CPP IM D12 (2)-(5). More extensive explanations are provided in our CPP119 Project Summary documents provided as support to this proposal and the associated asset lifecycle management reports (NW70.00.30-32).

Identified programme CPP119 – emergency maintenance opex – network assets	
D12(2) – (5)	**Explanation**
(2)(a)(i) description including aims and objectives	Emergency maintenance in this programme responds to unplanned events that impair the normal operation of our non lines and cables assets. These include: • Earths • Control systems • Protection and communication cables • Transformers • Distribution – building (includes grounds) • Distribution – kiosk (includes grounds) • Meters • Generators

- Switchgear
- Load management systems
- Asset management systems
- Distribution management systems.

This programme also includes our emergency contract management costs and associated asset mapping information costs.

The aim of this opex is to undertake network asset repairs as quickly as possible after unplanned outages in order to bring our distribution network back to at least its minimum acceptable and safe operating condition.

(2)(a)(ii) deliverability

This emergency maintenance programme will be carried out under our emergency contracts, which have been let to Connetics and ILS until 2015, with possible renewal for another two years.

(2)(a)(iii) contingency factors

There are no contingency factors provided for in this emergency maintenance programme

(2)(b) and (5) assumptions, obligations and step changes

We are subject to a number of obligations included in a wide range of legislation. Our main obligations are contained in our Statutory Compliance Manual. Of particular relevance to emergency maintenance are health and safety and civil defence requirements. Our emergency network asset programme includes the following allowances:

$000 (real)	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Protection	130	175	175	215	175	175	175
Distribution transformers	140	190	190	225	190	190	190
Distribution substations	25	35	35	45	35	35	35
Distribution switchgear	110	150	150	180	150	150	150
Load management	20	30	30	35	30	30	30
SCADA and control	90	120	120	145	120	120	120
Communications Equipment	15	20	20	30	20	20	20
Generators	5	5	5	10	5	5	5
Operations	5	5	5	10	5	5	5
Connection and contract management	160	215	215	215	215	215	215
Other asset management services	410	410	410	410	410	410	410

	Our emergency contracts were renegotiated in late FY13, and the unit rates in those contracts have increased. Accordingly our emergency budgets step up (in real terms) from FY14. In addition, in FY16 our stores and spares will be moved to a new lifelines standard building managed by Connetics. We have allocated the costs of this move across all asset categories in their emergency maintenance budgets in FY16.
(2)(c) and (3) forecasting methodology	There are no departures from consultants' recommendations in this capex programme.
(4) relevant policies	Our emergency works contracts are specified consistent with the following policies: • Procurement Policy OR00.00.19 and Contract management NW73.00.0 – we follow our procurement and contract management policies to achieve value for money by competitively tendering our work with a value over $20,000. • Delegations of Authority Policy OR00.00.11 – the overall budgeted expenditure for this programme is approved by the Board as part of the overall Asset Management Plan. The actual expenditure is approved as and when incurred, in compliance with the delegations of authority policy • Authorised Contractors NW73.10.15 – we ensure only authorised contactors are allowed access to our network • Health and Safety Policy OR00.00.01 – we follow our health and safety requirements to ensure the safety of the public and our personnel and contractors around our assets • Network operating standards, procedures and instructions (generally those policies designated NW20, NW21 and NW72.13) determine how our contractors work around our network assets during emergency maintenance and how they interface with our operators • Emergency Works Contract Management (NW72.20.03) sets out the terms and duties of our emergency works contractors • Spares are covered by procurement and stock management policies (generally those designated NW72.20)

9.19.6 Emergency maintenance – other programmes

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Explanations for our other emergency maintenance programmes are included in their Project Summary documents (CPP117 and CPP118). These are supported by their respective asset lifecycle management reports, which are listed in Section 9.2.2 of NW70.50.03. There are no contingency factors provided for within these programmes.

Our planning standards are not directly related to emergency maintenance, which is reactive. Our planning standards set the parameters of the network which influence how supply is able to be restored following an outage. For example our system security levels on different parts of the network determine how quickly the network is able to recover from a fault. Our system security standards are included in Section 6.2.7 of this proposal.

A full list of these is set out below.

Emergency maintenance programmes (not included as an identified project)		
Reference	**Project name**	**Description of assets included in emergency maintenance programmes**
CPP117	Overhead lines	These assets are 66kV, 33kV, 11kV and 400V overhead lines including poles, towers, cross arms, insulators and conductors

The policies identified as relevant for underground cable and network asset emergency maintenance (in 9.19 above) are also relevant for overhead lines emergency maintenance.

9.20 Scheduled maintenance

9.20.1 Aims and objectives

Scheduled maintenance is mainly associated with planned work including routine inspection and testing, site maintenance and vegetation management. Inspection works tend to be carried out at predetermined intervals or in accordance with prescribed criteria.

The objectives of these is to maintain safety for staff, contractors and the public, minimise the probability of network failure, minimise total life cycle costs and meet required operating conditions and performance standards.

Scheduled maintenance includes planned corrective or repair maintenance which arises as a result of our inspection and testing programmes.

This opex category has direct links to our service measures set out in Section 9.6 above. Without this expenditure our ability to meet these service level targets would be compromised.

9.20.2 Key features

Our scheduled maintenance for FY11 and FY12 was deferred due to the impact of the earthquakes and the immediate requirements on us to respond to unplanned events. Accordingly our scheduled maintenance will step up from FY13 onwards.

The following table summarises the value of each programme over the next period.

Opex – Scheduled maintenance			
Reference	**Name**	**Nominal value over next period ($m)**	**Identified project**
CPP100	Overhead lines sub transmission	8.0	
CPP101	Overhead lines 11kV and 400V	40.4	Yes
CPP102	Earths	2.2	

CPP103	Underground cables sub transmission	7.6	
CPP104	Underground cables 11kV and 400V	10.4	
CPP105	Mapping and asset storage	3.8	
CPP106	Control systems	5.5	
CPP107	Protection and pilots	5.2	
CPP108	Transformers	9.1	Yes
CPP109	Buildings, grounds and substations	22.9	Yes
CPP110	Meters	1.3	
CPP111	Generators	1.8	
CPP112	Switchgear	9.1	Yes
CPP121	Load management systems	2.0	
CPP123	Distribution management systems	1.8	
CPP120	Contingency maintenance	8.3	

9.20.3 Deliverability and prioritisation

Our scheduled maintenance is tendered out as part of our contracting model on a lowest price conforming attributes basis. The rationale for this is discussed in Section 9.11.2 above. Our scheduled maintenance programme is carried out with normal contracting arrangements in conjunction with our asset replacement capex. We prioritise work in accordance with our project prioritisation policy (NW70.60.14) which is described in Section 9.11.3 above.

As outlined above, in respect of our replacement capex we determine our replacement and maintenance priorities by following the general principle that the assets supplying the greatest number of consumers receive the highest priority. We try to mitigate disruptions to consumers by co-ordinating maintenance with other work and where possible carry out the work at periods of lower network loading.

9.20.4 Documents, policies and consultants reports

Our documents, policies and planning standards relevant to our scheduled maintenance programmes include:

- Asset Management Policy NW70.00.46
- Procurement Policy OR00.00.19
- Contract Management NW73.00.03

- Delegations of Authority Policy OR00.00.11
- Authorised Contractors NW73.10.15
- Health and Safety Policy OR00.00.01
- Environmental Sustainability Policy OR00.00.03
- Asset Lifecycle Management Reports for each asset class (NW70.00.22 – NW70.00.44)

In addition our technical specifications (listed at 9.2.4 in NW70.50.03) set out our maintenance and inspection procedures for each asset type on our network.

Their relevance to our scheduled maintenance programmes is summarised in Appendix 21.

9.20.5 Costing methods

Our annual maintenance opex and replacement capex forecasts are developed by the Infrastructure Lifecycle Manager and the Network Asset Manager. They are reviewed by the Corporate Management Team and then approved by the Orion board before being included in the AMP. A similar process has been adopted for our CPP forecasts (which will be reflected in our 2013 AMP). Our forecasts are revised each year, via our AMP planning process.

Forecasting the quantum and nature of maintenance (and replacement work) and determining budgets requires engineering experience and judgment in conjunction with historical data. Our budgeting process is set out below.

Forecast quantum and nature of work

Assessments are made about the quantum and nature of work to be completed each year for each asset category in terms of:

- scheduled maintenance
- non-scheduled maintenance
- emergency maintenance
- replacements (capex renewals).

These assessments are informed by time based, condition based and reliability based maintenance practices. We are planning to integrate our newly developed condition based risk management (CBRM) models for replacement as soon as practicable. The earthquakes have disrupted this planned development of our asset lifecycle management approach.

Our assessments also take in to account changes in the number or type of assets to be maintained (after consideration of replacement, creation, acquisition and disposal plans) and any changes in obligations such as regulatory changes, safety, vegetation and environmental requirements.

Review of prices from contractors and suppliers

The majority of scheduled and non scheduled maintenance works in tendered, with contractors providing materials in line with our specifications. Data is gathered from contract prices received over the prior year for similar types of work, by asset category. This data is entered into spreadsheets and analysed to determine recent market prices for each category of work (AMP budget category).

These recent market prices are used to derive the unit costs which are used for forecasting purposes.

In the case of major items of plant, where lead times may be significant and/or the technical specifications are of importance (for example switchgear, transformers and some protection and control assets), we procure the assets. Data is gathered for asset prices from tender pricing schedules and recent purchases for specific assets and analysed to determine market prices for each asset type.

Forecast budgets

Unit costs are applied to our forecast work plan for each programme of work. Actual costs reflect the contracts which are awarded after tendering.

Contingency

Our AMP scheduled maintenance forecasts have traditionally included an allowance for unforeseen maintenance. A similar allowance is included in our CPP scheduled maintenance forecast. This is for uncertainties that impact maintenance, predominantly scheduled maintenance, but potentially also non-scheduled and emergency expenditure.

We use a contingency of $1.5 million per year (in real terms) from year two onwards of the planning period, because it allows us to manage any unforeseen cost changes in future years. This is disclosed as a transparent amount rather than spread across all maintenance programmes. This amount was set by the Infrastructure Group based on analysis of a 10-year period of budgets versus actual expenditure.

High impact low probability (HILP) catastrophic events such as the 2010 and 2011 earthquakes are not covered by the contingency budget.

9.20.6 Scheduled maintenance – identified programmes

Our scheduled maintenance programmes for 11kV and 400V overhead lines, transformers, buildings, grounds and substations, and switchgear are included as identified programmes. The following information is provided in response to the requirements of D12(2)-(5). More extensive explanations are provided in our CPP101 Project Summary documents and the associated asset lifecycle management reports (NW70.00.25 and NW70.00.27).

Identified programme (CPP101) – scheduled maintenance – 11kV and 400V overhead lines	
D12(2) – (5)	**Explanation**
(2)(a)(i) description including aims and objectives	The main drivers for undertaking the programme are that assets are maintained in a timely and cost effective manner to ensure the condition and performance of our assets are such that they: • meet acceptable target levels of safety to people and property • provide acceptable levels of network reliability • ensure prudent cost effective management of our assets and associated risks. Assets must be maintained regularly. Allowing the assets' condition to deteriorate

significantly is not appropriate as the consequences of doing so pose a significant risk and are very costly to rectify.

This programme is closely related to the overhead lines replacement programme.

(2)(a)(ii) deliverability

This maintenance programme will be tendered for as each annual works programme is finalised. By having a smooth expenditure forecast overall we try to avoid peaks and troughs in the work load for our contractors. This enables us to achieve our medium to long term requirements and assists the contractors in their resourcing planning.

(2)(a)(iii) contingency factors

There are no contingency factors provided for in this maintenance programme.

(2)(b) and (5) assumptions, obligations and step changes

We are subject to a number of obligations included in a wide range of legislation. Our main obligations are contained in our Statutory Compliance Manual. Of particular relevance to scheduled maintenance are health and safety requirements. Our scheduled maintenance programme for overhead lines (11kV and 400V) assumes the following activities

	11kV (per annum)	**400V (per annum)**
Conductor replacement	130km	
Retightening	6 feeders (150km)	2000 sites plus all new lines/poles within 12-18 months
Crossarm and insulator replacement	300 sites	2000 sites
Retention conductors	72 sites	130 sites
Tree trimming	60 feeders	5000 street properties

This programme involves our maintenance of low voltage overhead lines.

Maintenance requirements are primarily based on a ‘Conditional Assessment Survey’ carried out every five years with a street by street visual check.

Every two years a corona camera inspection of all 11kV overhead lines is carried out. The camera provides the ability to visually detect partial discharge occurring on equipment e.g. cracked insulators and defective components at early stages of degradation, thus minimising unscheduled outages.

Maintenance work currently planned is as follows:

- re-tightening programme on a street by street basis of all line components to reduce wear and fatigue on the poles. The Re-tightening Cycle Programme specifies that:
  - New lines/poles are retightened within 12-18 months of installation; and
  - Re-tightened at 30 year intervals thereafter
- at the 30 year mark a full inspection of all equipment is carried out and remedial work is undertaken as required
- as part of the sub transmission (33kV) maintenance, the 11kV underbuilt is maintained:
  - Old 821 insulators replaced with new 1130W insulators
  - Hand binders replaced with distribution ties

	- Replace 7.5mmØ stay wires with new standard stay wires and replace anchor blocks - Copper tails changed to aluminium tails - Bimetal jumpers and joints replaced - Line guards changed to armour guards - Stay insulators changed to new standard insulators • the clearing of trees from lines to comply with regulations • the CCC installs outreach street lighting arms and tsunami alert warning sirens on our poles. Arc Innovations has also installed antennas and equipment for remote metering on existing poles. In these circumstances the additional loading to the poles is assessed and requires some poles to be changed to meet the additional load.
(2)(c) and (3)forecasting methodology	There are no departures from consultants' recommendations in this opex programme. We note we are currently in the process of implementing the CBRM approach to asset replacement, and it is possible we could refine our maintenance programme in the future once we have had more opportunity to integrate EA's CBRM models into our asset planning processes The method we have used to derive the costs of the forecast scheduled maintenance programmes is described above in Section 9.20.6 We adopt whole lifecycle practices for our network assets and focus on optimising the lifecycle costs for each asset group to meet agreed service level targets and future demand. We use a mixture of maintenance practices to service our equipment. No single method provides the ultimate solution from an asset management perspective but by using a combination of them we can tailor our maintenance schedule to best suit our transformers. Expenditure forecasts require the use of engineering experience and judgement in conjunction with historical asset performance/condition, and estimates of future maintenance requirements. Our proposed quality standards, described in Section 6 of this proposal, explain our expected reliability performance for our overhead lines during the CPP period. Our scheduled maintenance programmes are consistent with this. This scheduled maintenance programme is directly relevant to our network performance service measures outlined in Section 9.6. Without this expenditure we would not be able to deliver the SAIDI and SAIFI targets we have proposed for the CPP regulatory period. It also has indirect linkages to our health and safety and environmental service targets, which reach across our entire operation.
(4) relevant policies	Our scheduled maintenance works are specified consistent with the following policies: • Procurement Policy OR00.00.19 and Contract Management NW73.00.0 – we follow our procurement and contract management policies to achieve value for money by competitively tendering our work with a value over $20,000 • Delegations of Authority Policy OR00.00.11 – the overall budgeted expenditure for this programme is approved by the Board as part of the overall AMP. Actual expenditure is approved as and when incurred, in compliance with the delegations of authority policy • Authorised Contractors NW73.10.15 – we ensure only authorised contactors

	are allowed access to our network • Health and Safety Policy OR00.00.01 – we follow our health and safety requirements to ensure the safety of the public and our personnel and contractors around our assets • Inspection and Condition Assessment of Overhead Line Structures NW72.21.11 – sets out an inspection and assessment procedure for overhead lines • Overhead Line Work NW72.21.01, Overhead Line Standard Construction Drawings NW72.21.18, Earthing Installation NW 72.28.01, Earthing Testing NW 72.28.02, Vibration Dampers NW 72.21.13. – these standards outline the line construction methods and maintenance practices • Overhead Conductors NW74.23.17, Treated Softwood Timber Poles NW74.23.06, Hardwood Timber Poles NW74.23.08, Cross Arms NW74.23.19 and Approved Earthing Equipment and Application NW 74.23.20. – these specifications set out the requirements for materials • NZ Code of Practice for Electrical Safe Distances (NZCEP 34).

Identified programme (CPP108) – scheduled maintenance – transformers

D12(2) – (5)	**Explanation**
(2)(a)(i) description including aims and objectives	The main drivers for undertaking the programme are that assets are maintained in a timely and cost effective manner to ensure the condition and performance of our assets are such that they: • meet acceptable target levels of safety to people and property • provide acceptable levels of network reliability • ensure prudent cost effective management of our assets and associated risks. Assets must be maintained regularly. This programme maintains on a periodic basis high voltage regulators and power and distribution transformers for which it has been determined that maintenance is the cost effective way to ensure reliability of electricity supply and meeting service level targets (including safety).
(2)(a)(ii) deliverability	This maintenance programme will be tendered for as each annual works programme is finalised. By having a smooth expenditure forecast overall we try to avoid peaks and troughs in the work load for our contractors. This enables us to achieve our medium to long term requirements and assists the contractors in their resourcing planning.
(2)(a)(iii) contingency factors	There are no contingency factors provided for in this maintenance programme.
(2)(b) and (5) assumptions, obligations and step changes	We are subject to a number of obligations included in a wide range of legislation. Our main obligations are contained in our Statutory Compliance Manual. Of particular relevance to scheduled maintenance are health and safety requirements. Our scheduled maintenance programme for transformers assumes the following activities:

	Voltage regulators – included with the annual and four yearly tap changer maintenance programmes
	Power transformers – half life refurbishments, online oil testing, annual tap changer maintenance
	Distribution transformers – maintained when relocated or line maintenance is undertaken. Maintenance decision is based on replacement or life extension options, ie: lowest lifetime cost
(2)(c) and (3)forecasting methodology	There are no departures from consultants' recommendations in this opex programme. We note we are currently in the process of implementing the CBRM approach to asset replacement, and it is possible we could refine our maintenance programme as a result. The method we have used to derive the costs of the forecast scheduled maintenance programmes is described above in Section 9.20.6 This scheduled maintenance programme is directly relevant to our network performance service measures outlined in Section 9.6. Without this expenditure we would not be able to deliver the SAIDI and SAIFI targets we have proposed for the CPP regulatory period. It also has indirect linkages to our health and safety and environmental service targets, which reach across our entire operation.
(4) relevant policies	Our scheduled maintenance works are specified consistent with the following policies: • Procurement Policy OR00.00.19 and Contract Management NW73.00.0 - we follow our procurement and contract management policies to achieve value for money by competitively tendering our work with a value over $20,000 • Delegations of Authority Policy OR00.00.11 – the overall budgeted expenditure for this programme is approved by the Board as part of the overall AMP. Actual expenditure is approved as and when incurred, in compliance with the delegations of authority policy • Authorised Contractors NW73.10.15 – we ensure only authorised contactors are allowed access to our network • Health and Safety Policy OR00.00.01 – we follow our health and safety requirements to ensure the safety of the public and our personnel and contractors around our assets • NZ Code of Practice for Electrical Safe Distances (NZCEP 34).

Identified programme (CPP109)– scheduled maintenance – buildings, grounds and substations

D12(2) – (5)	Explanation
(2)(a)(i) description including aims and objectives	We own a large number of properties and buildings which are solely used to house electrical equipment necessary for the operation and control of our electrical sub transmission and distribution networks. The buildings, known as substations, comprise the following categories: zone, network, distribution – building and distribution – and kiosk. This programme does not cover the multiple assets which are housed within substations.

The main objectives of this programme are to:

- ensure the safety of the public and our personnel and contractors around our assets
- ensure security
- ensure that properties remain environmentally sound so that the installed equipment is not compromised
- repair buildings that have suffered damage
- ensure kiosks are prepared to deter rust and buildings are repainted to protect against water ingress through block work

The main drivers for this programme include:

- acceptable levels of safety to people and property
- asset management and risk management. The risks our network buildings are exposed to are:
    - seismic movement – we have undertaken to seismically strengthen key building substations
    - liquefaction
    - defective drainage, guttering – grounds maintenance contracts now cover the clearing of drains and gutters
    - roof leaks – roof replacement programme is ongoing
    - vegetation/tree roots – removal or maintenance of large trees/shrubs in close proximity to our substations as a variation to our grounds maintenance contracts
    - vandalism – repairs carried out as soon as incident is reported
    - rust – replacement programme in place for kiosks situated in close proximity to the coast
    - subsidence
    - extreme weather conditions
    - fire – smoke detectors installed in zone substation buildings.

(2)(a)(ii) deliverability

This maintenance programme will be tendered as each annual works programme is finalised. By having a smooth expenditure forecast overall we try to avoid peaks and troughs in the workload for our contractors. This enables us to achieve our medium to long term requirements and assists the contractors in their resource planning. Scheduling of the work can be altered to some extent to take into account resource constraints and other externalities.

(2)(a)(iii) contingency factors

There are no contingency factors provided for in this maintenance programme.

(2)(b) and (5) assumptions, obligations and step changes

We are subject to a number of obligations included in a wide range of legislation. Our main obligations are contained in our Statutory Compliance Manual. Of particular relevance to scheduled maintenance are health and safety requirements. Our scheduled maintenance programme for buildings, grounds and substations comprises:

$m(real)	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Zone sub	2.2	2.1	1.9	1.5	1.5	1.5	1.5

land, site development, buildings and structures							
Distribution substations (including land)	0.7	0.7	0.7	0.7	0.7	0.4	0.4
Other items	0.4	0.4	0.4	0.4	0.4	0.4	0.4

Our five-year maintenance programme has recently commenced with the view to repair all of our buildings which have suffered earthquake damage. All our buildings and land are inspected regularly, and minor repairs are undertaken as they are identified.

Property maintenance is expected to remain at a relatively constant level, although many of the older consumer owned substations will require seismic upgrading over time if they are retained. Consumer-owned substations that require maintenance or strengthening to remove risk to our equipment may present some problems in relation to who will bear the cost of this work. These will be assessed on a case by case basis.

Upgrading is underway on some of our rural zone substation buildings constructed in modular concrete sections with predominantly steel framed glass ends. The ends are being replaced with about two-thirds solid wall, with aluminium doors and windows. This will help with weather-tightness and security.

Our substations are maintained on an as-required basis, with most general maintenance work identified during six-monthly inspections. Work such as damage repair, ground maintenance, graffiti removal, painting, signage and lock replacement is ongoing.

A number of our substation buildings were constructed with a flat concrete roof with a tar-based membrane covering. These have been prone to leaking when cracks develop in the concrete. Over the past few years we have implemented a programme to upgrade these buildings by constructing a new pitched Coloursteel roof over the top. We expect to have covered all of the original flat concrete roofs within the next few years.

Some of the older kiosk foundations have moved due to surrounding land movement. They need to be levelled to relieve stress on the attached cables. A small number of them are being attended to each year.

We maintain and repaint our kiosks as required with more focus to deter rust on the coastal areas. Buildings are repainted approximately every 10 years and we are now using a silicon based product to provide a waterproof membrane and protect the substation from water ingress through the block work.

Graffiti is an ongoing problem at virtually all of our sites. We remove it as soon as possible after it is reported. We liaise with the local councils and community groups in our area to assist us with this problem. Orion now has a specific email set up where members of the community can report graffiti. We aim to attend to

	graffiti within 48 hours.
(2)(c) and (3)forecasting methodology	There are no departures from consultants' recommendations in this opex programme. The method we have used to derive the costs of the forecast scheduled maintenance programmes is described above in Section 9.20.6. We adopt whole lifecycle practices for our network assets and focus on optimising the lifecycle costs for each asset group to meet agreed service level targets and future demand. We use a mixture of maintenance practices to service our equipment. No single method provides the ultimate solution from an asset management perspective but by using a combination of them we can tailor our maintenance schedule to best suit our transformers. Expenditure forecasts require the use of engineering experience and judgement in conjunction with historical asset performance/condition, and estimates of future maintenance requirements. Our proposed quality standards, described in Section 6 of this proposal, explain our expected reliability performance for our overhead lines during the CPP period. Our scheduled maintenance programmes are consistent with this. This scheduled maintenance programme is directly relevant to our network performance service measures outlined in Section 9.6. Without this expenditure we would not be able to deliver the SAIDI and SAIFI targets we have proposed for the CPP regulatory period. It also has indirect linkages to our health and safety and environmental service targets, which reach across our entire operation.
(4) relevant policies	Our scheduled maintenance works are specified consistent with the following policies: • Procurement Policy OR00.00.19 and Contract Management NW73.00.0 – we follow our procurement and contract management policies to achieve value for money by competitively tendering our work with a value over $20,000 • Delegations of Authority Policy OR00.00.11 – the overall budgeted expenditure for this programme is approved by the Board as part of the overall AMP. Actual expenditure is approved as and when incurred, in compliance with the delegations of authority policy • Authorised contractors NW73.10.15 – we ensure only authorised contactors are allowed access to our network • Health and Safety Policy OR00.00.01 – we follow our health and safety requirements to ensure the safety of the public and our personnel and contractors around our assets Further links to policies are set out in Appendix 21.

Identified programme (CPP112) – scheduled maintenance – switchgear

D12(2) – (5)	Explanation
(2)(a)(i) description including aims and objectives	The assets included in this programme are high voltage and low voltage switchgear and high voltage circuit breakers. These include; • Ring Main Units (Epoxy Insulated, Switches (Fused and Non-fused)) • Oil switches, fused and non-fused (Fuse Switch/OIS) • Air break isolators • Sectionalisers • Low voltage switches • HV Circuit breakers - 11kV – gas, oil vacuum - 33kV – oil, vacuum - 66kV – gas, oil The main drivers for undertaking the programme are that assets are maintained in a timely and cost effective manner to ensure the condition and performance of our assets are such that they: • meet acceptable target levels of safety to people and property • provide acceptable levels of network reliability • ensure prudent cost effective management of our assets and associated risks. Assets must be maintained regularly. Allowing the assets' condition to deteriorate significantly is not appropriate as the consequences of doing so pose a significant risk and are very costly to rectify. This programme is closely related to the switchgear replacement programme.
(2)(a)(ii) deliverability	This maintenance programme will be tendered for as each annual works programme is finalised. By having a smooth expenditure forecast overall we try to avoid peaks and troughs in the work load for our contractors. This enables us to achieve our medium to long term requirements and assists the contractors in their resourcing planning.
(2)(a)(iii) contingency factors	There are no contingency factors provided for in this maintenance programme.
(2)(b) and (5) assumptions, obligations and step changes	We are subject to a number of obligations included in a wide range of legislation. Our main obligations are contained in our Statutory Compliance Manual. Of particular relevance to scheduled maintenance are health and safety requirements. Our scheduled maintenance programme for switchgear assumes the following activities: • 11kV MSUs are virtually maintenance free, with the exception of those units in close proximity to the sea, which are maintained every four years • ring-main units and oil switches in indoor situations are maintained as part of the programme of work (four or eight yearly) for the substation in which they are installed • a check on the operation of standard ABIs is included when a line retighten contract is carried out each year. Other maintenance work is on an as-required basis • sectionalisers are maintained every eight years, with an annual external

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inspection

substation low voltage panels are inspected every six months. Other switches are inspected on a five-yearly basis. We are just over halfway through a four-year programme to install safety barriers over the open and live busbars and switches
HV CBs are checked during the substation maintenance rounds. Major faults result in the CB being removed from service and overhauled. All oil filled CBs are serviced following operation under fault conditions. All metal-clad switchgear (33kV & 11kV indoor CBs) are tested for partial discharge.

<table>
<tr><th>$m real</th><th>FY13</th><th>FY14</th><th>FY15</th><th>FY16</th><th>FY17</th><th>FY18</th><th>FY19</th></tr>
<tr><td></td><td>1.2</td><td>1.2</td><td>1.2</td><td>1.0</td><td>1.0</td><td>1.0</td><td>1.0</td></tr>
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Higher costs are included in the first three years to allow for repairs to damaged link boxes due to demolition activity in the CBD. Longer term, allowance is included for additional maintenance for spur assets and additional partial discharge testing and maintenance for aging switchgear
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<td>(2)(c) and (3)forecasting methodology</td>
<td>There are no departures from consultants’ recommendations in this opex programme. We note we are currently in the process of implementing the CBRM approach to asset replacement, and it is possible we could refine our maintenance programme in the future once we have had more opportunity to integrate EA’s CBRM models into our asset planning processes
The method we have used to derive the costs of the forecast scheduled maintenance programmes is described above in Section 9.20.6</td>
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<td>(4) relevant policies</td>
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Our scheduled maintenance works are specified consistent with the following policies:

Procurement Policy OR00.00.19 and Contract Management NW73.00.0 - we follow our procurement and contract management policies to achieve value for money by competitively tendering our work with a value over $20,000
Delegations of Authority Policy OR00.00.11 - the overall budgeted expenditure for this programme is approved by the Board as part of the overall AMP. Actual expenditure is approved as and when incurred, in compliance with the delegations of authority policy
Authorised Contractors NW73.10.15 - we ensure only authorised contactors are allowed access to our network
Health and Safety Policy OR00.00.01 - we follow our health and safety requirements to ensure the safety of the public and our personnel and contractors around our assets
NZ Code of Practice for Electrical Safe Distances (NZCEP 34).

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9.20.7 Scheduled maintenance – other

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Explanations for our other scheduled maintenance programmes are included in their Project Summary documents. These are supported by their respective asset lifecycle management reports. There are no contingency factors provided for within these programmes.

A full list of these programmes is set out below.

Scheduled maintenance programmes (not included as an identified project)		
Reference	**Project Name**	**Description of assets included in scheduled maintenance programme**
CPP100	Overhead lines sub transmission	The overhead subtransmission network is primarily made up of 33kV pole lines and 66kV pole/tower lines. These lines are built using timber, concrete and steel poles and steel towers with a range of conductor and foundation types.
CPP102	Earths	These assets protect personnel by ensuring all exposed metal not used for carrying electrical current is electrically connected to earth.
CPP103	Underground cables sub transmission	Includes 66kV self contained oil-filled three core aluminium cables and XLPE single core copper cables and 33kV PILCA and XLPE cables.
CPP104	Underground cables 11kV and 400V	The assets that are included in this programme are 11kV and 400V underground cables and distribution hardware. These include: • 11kV, 400V cable (cross-linked polyethylene (XLPE) single core copper, paper insulated lead cable armour (PILCA) grease-filled copper, PILCA grease-filled aluminium, XLPE single core aluminium • PVC 400V cable (copper, aluminium) • Distribution cabinets (also known as link boxes) • Distribution boxes (also known as boundary boxes)
CPP105	Mapping and asset storage	This programme includes the process of recording all relevant information about our network assets, which is continually updated due to our inspection and maintenance programmes. The asset storage component includes the costs for our contract to manage our long term spares and emergency stock.
CPP106	Control systems	The assets that are included in this programme are our communication systems and distribution management system (DMS). These include: • Communication systems - Voice communications systems

		- Data communications systems (including SCADA) • DMS – a collection of applications designed to monitor and control the distribution network efficiently and reliably. It acts as a decision support system to assist the system control operators and field operating personnel with monitoring and control of the electricity distribution system. Improving the reliability and quality of service in terms of reducing and minimizing outage time, maintaining acceptable frequency and voltage levels are the key deliverables of a DMS. DMS includes: - Network model - Remote terminal units - SCADA master station DMS applications (outage management system, mobile despatch, historian, real-time load flow analysis, information interfaces with consumers)
CPP107	Protection and pilots	The work undertaken in this programme involves replacement of our communication cables and protection systems. The assets included in this programme are: • Communication cables and distribution cabinets • Protection systems including: - Protection relays - Communication platforms - Ground fault neutralisers - Neutral earthing resistors - Current transformers - Voltage transformers
CPP110	Meters	Includes high voltage (11kV) consumer metering, Transpower GXP metering, power quality measurement metering and monitoring equipment and maximum demand ammeters.
CPP111	Generators	Includes eighteen medium to large diesel generators. Ten 550kVA generators can be strategically placed throughout our urban network. Three of them have synchronisation gear fitted. Along with these generators we also have three truck-mounted units of 375, 400 and 440kVA (mobile) and one 110kVA trailer mounted generator, which are used to restore supply at a distribution level during a fault or planned work. The truck-mounted units are all fitted with synchronisation gear. We have a further 550kVA unit attached to our main office building with synchronisation gear and a 30kVA without synchronisation gear. Recently we have purchased two 2500kVA 11kV generators with synchronisation gear.
CPP121	Load management systems	Includes Orion's load management master station and RTUs, upper South Island load management system, ripple injection

		system, communications.
CPP123	Distribution management systems	A distribution management system including a network model and comprehensive SCADA master station.
CPP120	Contingency maintenance	An allowance for unforeseen maintenance. This provisions for uncertainties that impact maintenance, predominantly scheduled maintenance, but potentially also non-scheduled and emergency) expenditure.

Appendix 21 also explains which of our policy documents are relevant to the scheduled maintenance programmes.

9.21 Non-scheduled maintenance

9.21.1 Aims and objectives

Our non-scheduled maintenance forecast is for unknown issues that may occur but would not be carried out under the emergency contract. It is primarily concerned with unplanned work that includes fault rectification that is undertaken after the initial emergency response.

The aims and objectives for this corrective or repair work are primarily to restore a network component which has been damaged to its original state, where this was not achieved in the initial response. This restores network performance standards and enables our network to meet target service levels.

9.21.2 Key features

Our forecasts for non scheduled maintenance are similar to historical levels. They are comprised of the following four budget categories:

Opex – Non scheduled maintenance			
Reference	**Name**	**Nominal value over next period ($m)**	**Identified project**
CPP113	Overhead lines	6.6	
CPP115	Underground cables	2.4	
CPP114	Network assets	4.7	
CPP116	Buildings, grounds and substations	2.9	

9.21.3 Deliverability and prioritisation

Like our scheduled maintenance our non scheduled maintenance is tendered out as part of our contracting model. The rationale for this is discussed in Section 9.11 above. This programme is expected to be able to be carried out with normal contracting arrangements in conjunction with our asset replacement capex. We prioritise work in accordance with our project prioritisation policy (NW70.60.14) which is described in Section 9.11.2 above.

As outlined above in respect of replacement capex, we determine our replacement and maintenance priorities by following the general principle that the assets supplying the greatest number of consumers receive the highest priority. We try to mitigate disruption to consumers by co-ordinating maintenance with other work and where possible carry out the work during periods of lower network loading.

9.21.4 Documents, policies and consultants reports

Our documents, policies and planning standards relevant to our non scheduled maintenance programmes are the same as those set out above in 9.20.4 in relation to scheduled maintenance.

Their relevance to non scheduled maintenance programmes is summarised in Appendix 21.

9.21.5 Costing methods

Section 9.20.5 above describes the way in which our forecasts are derived for scheduled maintenance. The same process is used for deriving non scheduled maintenance costs.

9.21.6 Non scheduled maintenance – identified programmes

No non-scheduled maintenance programmes have been selected as identified programmes.

9.21.7 Non scheduled maintenance - other

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No non-scheduled maintenance programmes have been included as identified programmes. Explanations for all non scheduled maintenance programmes are included in their Project Summary documents. These are supported by their respective asset lifecycle management reports. There are no contingency factors provided for within these programmes.

A full list of these programmes is set out below.

Non scheduled maintenance programmes (not included as an identified project)

Reference	Project name	Description of assets included in non scheduled maintenance programme
CPP113	Overhead lines	66kV, 33kV, 11kV and 400V lines including poles, conductor, crossarms and insulators
CPP115	Underground cables	66kV, 33kV, 11kV and 400V cables plus distribution cabinets and

		boxes
CPP114	Network assets	Power and distribution transformers, switchgear, voltage regulators, protection systems, communication and control systems, distribution management systems, metering and generators
CPP116	Buildings, grounds and substations	All substation buildings, kiosks and associated land and improvements including fences and outdoor structures

Appendix 21 also explains which of our policy documents are relevant to each of the scheduled maintenance programmes.

9.22 Network management and operations opex

9.22.1 Key features

Network management and operations opex is an identified programme. This group manages and operates our network. This group comprises 75% of Orion's current employees and this programme has approximately 25% of Orion's annual opex. It comprises support activities related to the management and operation of our network which include:

- safety and risk management
- lifecycle management
  - data management
  - GIS
  - contract administration
  - property management
- network strategic planning
- network asset management
  - reticulation asset management
  - substation asset management
  - distribution services
    - customer services
    - connections
    - distribution
- operations management
  - control centre
  - contact centre
  - field response
  - network access management
  - operations services
  - release planning
- engineering support
  - technical management.

Our forecast opex for the next period is presented in the following table.

Opex – network management and operations

Reference	Name	Nominal value over next period ($m)	Identified project
CPP167	Infrastructure management	118.6	Yes

Our infrastructure management opex programme is included as an identified programme. The following information is provided in response to the requirements of D12(2)-(5). More extensive explanations are provided in CPP167 Project Summary document.

Identified programme (CPP167) – network management and operations opex

D12(2) – (5)	Explanation
(2)(a)(i) description including aims and objectives	Our overarching purpose is to deliver a safe, secure and cost effective supply of electricity to our customers. This opex programme covers a number of areas of indirect overheads in the infrastructure team, which is responsible for managing Orion's assets to achieve that purpose. The key objectives for each team are: • management – provide leadership and direction for the infrastructure management function, and coordinate and manage all activities associated with network infrastructure. To be achieved in accordance with the goals and objectives of the organisation to ensure safe, sustainable, customer focused outcomes. Provision of quality management to ensure we retain value, build resilience, optimally develop and safely operate the network. Responsibility for opex and capex expenditure and associated contractor management for all work associated with our network infrastructure. Management of approved business growth ventures relating to core network activities. • safety and risk management – the overall focus for this group is to keep the public and our workers (including contractors) safe. To achieve this we use a risk based approach to safety to help us focus on the most significant risks. Direct communication with and via media is essential in getting the message out to the general public. Regular monitoring of safety statistics and complaints is an important part of this role as is investigations into safety and related issues • lifecycle management – to plan and document lifecycle management for the existing electrical and property assets. Lifecycle management includes quantifying assets, their location, condition and capability from acquisition to disposal. Maintenance and renewal planning and modelling is a core function • data management – to manage the WASP (Works, Assets, Solutions and People) asset data base to support the lifecycle property function and asset management functions. Control access to and update of key network documents and to manage the preparation of our annual AMP • GIS – to manage the GIS data base to support the lifecycle property function and asset management functions, support the operations group with the

provision of an electrical connectivity diagram, provide maps to contractors, designers and interested parties to minimise the impact of contractor hits on our assets

- contract administration – to provide a credible and efficient contract administration function for the asset management and property groups. This includes the process of compiling contracts, tendering, notice to tenders and preparation of comparative bids for engineering evaluation. Communication with contractors and receiving and verifying invoices is an essential part of this process
- property management – to manage corporate and network properties and the management of contractors working on or around our properties. These properties include corporate properties such as our head office as well as 315 building substations and about 4000 kiosk substations
- strategic planning – to develop long term plans for development of the electrical network. Considerations include network resilience, public and worker safety, service level expectations and network capacity planning. Provision of optimal outcomes and challenging the status quo is a focus
- network asset management – to work closely with strategic planning, life cycle and operations teams to ensure a safe, secure and reliable network is constructed, maintained and renewed. Focus is on the physical development and stewardship of the network asset. Connection and disconnection of consumers is a core function as is physical engineering and management of contractors working on or adjacent to our network.
- reticulation asset management – to determine maintenance and replacement programme priorities for all network cables, lines and associated equipment. To apply appropriate risk management assessments and techniques to optimise lifecycle costs and to minimise safety risks
- substation asset management – to coordinate the planning, design, construction, replacement and maintenance of substation assets. To review substation maintenance practices to reflect technological improvements in order to minimise lifecycle costs and improving reliability
- distribution services – to safely manage reticulation works contracts involving network upgrades, replacements, maintenance, additions and removals. The majority of this work involves the management of contractors by formal contract. The customer services team manages the interface with consumers especially with respect to trees in close proximity to power lines and technical inspection services on private land. The connections team manages new and modified customer connections and network extensions. The distribution team manages maintenance, removal and reinforcement works associated with the overhead and underground reticulated network
- operations management – to ensure efficient operation and responsive service from our contact centre and centralised control centre to ensure a safe, reliable service to our consumers. Providing safe contractor access to our network is an essential function as is monitoring our network performance and quality. Management of network load to minimise network constraints or offset capital investment in the network is also core function. Our faults service and customer contact centre are part of this group

- engineering support – to support the strategic planning, asset management and operations groups. A core function is the development and management of protection and communications standards and interfacing with our technical service providers. Assessment of new equipment is a key function as is development of our engineering staff.

(2)(a)(ii) deliverability

The majority of this programme spend is relatively fixed as it relates to employee remuneration for current employees. Any additional employees required will be recruited as required. There are no expected constraints in delivering the planned expenditure.

This expenditure programme is primarily based on the expected workloads of our current employees. Priority is given to additional expenditure which will reduce the workload for employees who have high challenging workloads. This is addressed by employing additional employees where and when required to meet our aims and objectives.

The following table sets out the current and forecast FTEs for each group during the next period.

Group (includes technical engineers)	**FY13**	**By FY19**	**Explanation for changes**
Network management	6	6	
Safety and risk management	3	4	Increasing safety compliance requirements
Lifecycle management and data management	8	9	Development of lifecycle management approaches
GIS	7	9	Earthquake recovery and rebuild
Contract administration	2	3	Earthquake recovery and rebuild
Property management	7	7	
Strategic planning	3	5	Manage spur asset integration and new technologies
Network reticulation and substation asset management	9	11	Earthquake recovery and rebuild
Distribution, customer and connection services	28	28	
Operations management	7	7	
Control centre and field response	26	31	Earthquake recovery, demolition and connection enquiries
Contact centre	8	10	Earthquake recovery and rebuild
Network access management	1	1	
Operations services	4	5	Earthquake recovery and rebuild
Release planning	4	5	Earthquake recovery and rebuild
Engineering support	8	10	Support for protection systems

and technical management		
Total	131	151

(2)(a)(iii) contingency factors

There are no contingency factors provided for in this opex programme.

(2)(b) and (5) assumptions, obligations and step changes

We are subject to a number of obligations included in a wide range of legislation. Our main obligations are contained in our statutory compliance manual. Of particular relevance to network management functions are health and safety requirements.

Our network management and operations opex forecast comprises:

$m(real)	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Operations	5.3	5.7	5.8	6.0	6.0	6.1	6.1
Connection and contract management	2.4	2.7	2.7	2.7	2.7	2.7	2.7
Network management services	6.0	7.2	7.7	7.7	7.4	7.4	7.5

The step changes are driven from staffing levels, explained above. There was a similar step up between FY11 (108 FTE) and FY13 (131 FTE) which also included increases in staffing levels not directly related to the earthquakes. In particular we:

- created six new roles in distribution services
- employed six new technical engineers as a deliberate development programme to bring in and develop our technical skills in order to manage succession for older expertise
- added a new trainee operator, again as a skills development strategy
- increased functionality in the property management team
- provided additional engineering administration assistance to assist our engineers manage their work loads
- increased numbers of operators and controllers to reduce the amount of overtime which was previously being required
- increased asset managers due to additional regulatory requirements and investment in development of our lifecycle asset management approach
- increased support for new systems (such as PowerOn).

Approximately 90% of total costs in this programme are employee remuneration. Our forecasts assume that average remuneration for current employees is relatively constant (in real terms). Additional employees which are to be added during the forecast period are forecast be recruited at the same costs, in real terms, for like positions. Our forecasts include minor real increases for expected promotions of existing staff, to higher pay grades.

Our cost escalation approach to deriving nominal forecast expenditure is explained in detail in Section 9.26 below.

Our remaining costs (10%) are made up of training, vehicle, equipment and

	uniform costs as well as recruitment costs. Some step increases in these costs are assumed to account for changes in legislation (compensation claims), consultancy and legal (for the same reason and also expected land issues with CERA) and training and vehicle costs which align with staffing numbers.
(2)(c) and (3)forecasting methodology	There are no departures from consultants' recommendations in this opex programme. Our forecasting and costing methods are described above. Further supporting explanations are included in the CPP167 Project Summary document. This network support group is an integral part of Orion achieving all of our service targets. It is this group which is primarily responsible for the operation, maintenance and development of our electricity distribution network. Accordingly, the achievement of all network performance, restoration, customer service, environmental and health and safety measures are of direct relevance to this programme.
(4) relevant policies	Our Project Summary document sets out all of the relevant policies and reports for this category of opex.

9.23 General management, administration and overheads opex

9.23.1 Aims and objectives

The objective of our general management, administration and overheads opex is to manage operations so that they are safe, economically efficient, reliable and cost-effective for consumers. This category of opex is not directly incurred in the physical operation and maintenance of our network but it supports these activities.

It includes corporate activities, finance, corporate information systems, commercial and regulatory functions, communications and engagement, property maintenance, material damage and business interruption insurance and special projects.

9.23.2 Key features

The forecast opex for this opex category for the next period is presented in the following table.

Opex – General management, administration and overheads

Reference	Name	Nominal value over next period ($m)	Identified project
CPP160	Corporate	27.1	Yes
CPP161	Finance	8.9	
CPP164	Information solutions – corporate systems	16.4	Yes

CPP165	Commercial and regulatory	14.4	Yes
CPP166	Communications and engagement	8.4	
CPP168	Property maintenance	7.7	
CPP169	Insurance – material damage and business interruption	20.1	
CPP170	Earthquakes – overheads/head office	2.4	
CPP171	Special projects	7.3	

9.23.3 Deliverability

Like our network management and operations support opex, corporate opex is predominantly delivered by our employees. Where necessary we change our employee numbers or reassign people to different tasks or responsibilities in order to achieve the objectives outlined above. We also use external resources where necessary, either contractors or consultants, to supplement our internal resources and expertise as required.

Many of our compliance obligations require us to obtain independent input, such as financial and regulatory audits.

Our forecast general management, administration and overheads opex is relatively consistent from year to year with the level we believe we require in order to support our core network management activities and ensure our consumers are provided with electricity delivery services at a quality which is consistent with their expectations. We foresee no issues with being able to meet our obligations within this programme.

We have included a special projects budget which provides us with flexibility to respond to strategic management issues as they arise. There are no contingencies included within this programme's forecast opex.

9.23.4 Policies and plans

The policies and plans which are relevant to our general management, administration and overheads opex are set out below:

- OR00.10.17 Building Emergency Plan – 200-210 Armagh St
- OR00.00.14 Credit Card – Policy
- OR00.00.11 Delegations of Authority – Policy
- OR00.00.03 Environmental – Sustainability Policy
- OR00.00.08 Fraud and Theft – Policy
- OR00.00.06 Hazard Management Plan
- OR00.00.02 Health and Safety – Committee Constitution
- OR00.00.01 Health and Safety – Policy
- OR00.00.18 Housekeeping – Policy
- OR00.00.05 Human Resources – Policy
- OR00.00.13 Information Systems

- OR00.00.07 Major Outage Communication Plan
- OR00.00.22 Media Policy
- OR00.00.21 Media Policy – Social
- OR00.00.09 Motor Vehicle – Policy
- OR00.00.12 Orion Sponsorship
- OR00.00.15 Police Reference Checks – Policy
- OR00.00.10 Privacy – Policy
- OR00.00.19 Procurement (Equipment Purchasing) – Policy
- OR00.00.16 Protected Disclosures Policy
- OR00.00.04 Staff Travel – Policy
- Statement of Intent
- Asset Management Plan.

Their relevance to this category of opex is summarised in Appendix 21. Our network planning standards are not directly relevant to this category of opex.

9.23.5 General management, administration and overheads opex – identified programmes

Our corporate opex is included as an identified programme. The following information is provided in response to the requirements of D12(2)-(5). More extensive explanations are provided in our CPP160 Project Summary document.

Identified programme (CPP160) - corporate opex	
D12(2) – (5)	**Explanation**
(2)(a)(i) description including aims and objectives	The objective of our corporate expenditure is to manage operations so that they are safe, economically efficient, resilient, reliable and cost-effective for consumers. The activities included in this opex category are: • board – the board is ultimately responsible for setting the goals of the company and for its compliance with law and for its performance • corporate management team – the CEO and his direct management reports are responsible for the overall management of the company, within specified delegated authorities and within authorised policies • human resources – the human resources manager assists line managers (including the CEO) in their employee management responsibilities. Responsibility for line management remains with line management, not the HR Manager • fleet management – facilitates getting the right people in the right vehicles in the right place at the right time. Fleet management works closely with line managers throughout the company to ensure vehicles are fit for purpose, safe, reliable, efficient and cost effective.

(2)(a)(ii) deliverability	The directors are experienced business people who have a range of skills and experience. Shareholders' director rotation and retirement policy ensures that there is renewal over time so that the company benefits from fresh governance perspectives, while retaining continuity. The corporate management team is very experienced and it also has a balance of skills and experience. The HR Manager is qualified and is very experienced. She is assisted by a capable PA. The fleet management function also has significant skills and experience. Policy development and management systems (including IT) have developed over time to ensure that the company can deliver results. The board and management are comfortable and are encouraged to seek expert independent advice and services as appropriate. This programme's spend is relatively fixed as it relates to employee remuneration for current employees. Any additional employees required will be recruited as required. There are no expected constraints in delivering the planned expenditure.
(2)(a)(iii) contingency factors	There are no contingency factors provided for in this opex category.
(2)(b) and (5) assumptions, obligations and step changes	As proportions, approximately: • 89% of the board's total annual forecast costs is for the directors' fees and remuneration • 76% of corporate management's total annual forecast costs is for the CEO's and his direct reports' remuneration costs including benefits and FBT, 7% is for audit fees, 5% is for AMI stadium sponsorship and 4% is for independent expert advice The company does not have an in-house legal department • 24% of the human resources function's total annual forecast costs is for the remuneration of the PA and 24% is for medical and occupational health. Other smaller centralised costs here include independent advice (3%) social club donation (3%), staff training (10%), staff functions (9%) and staff survey (3%) • vehicle costs are recovered via a monthly internal charges 'lease' to each operational cost centre that uses the vehicles. This 'internal lease' is intended to cover costs, including fuel, maintenance, registration, insurance, depreciation expense and a return on investment. Fleet direct costs comprise depreciation, fuel, repairs and maintenance, other costs (tyres, registrations, RUC and WOF). Fleet management indirect costs comprise 0.5 FTE employee cost, insurance costs and other incidental costs. Increases in corporate expenditure from FY13 onwards reflect: • we have had a long standing sponsorship agreement with AMI Stadium which was temporarily halted due to earthquake damage to the previous stadium and will recommence in FY13

	• our forecast spend on management training/development for the corporate group has been increased • an increase of one FTE in HR in FY13 • an increase in medical and occupational health (and to a lesser extent host expenses).
(2)(c) and (3) forecasting methodology	Our opex forecasts assume that no increases in FTEs occur in the CPP forecast period. Total FTEs assumed for the CPP forecast period are as follows: • 0.0 – for board – no employees • 8.0 – for corporate management – includes the CEO and a PA • 1.0 – for HR – this is a PA • 0.0 – for fleet management – this FTE is already included in Finance. There are no departures from consultants' recommendations in this opex programme. Our forecasting and costing methods are described above. Further supporting explanations are included in our Project Summary document. The corporate group is not as directly responsible for the service targets of the infrastructure management group (as outlined in Section 9.6 above). However, the corporate group is able to facilitate the achievement of the service targets by ensuring the corporate policies and strategies are well communicated, endorsed and demonstrated at the senior management level.
(4) relevant policies	Our Project Summary document sets out all of the relevant policies and reports for this category of opex

Our corporate systems opex is also included as an identified programme. The following information is provided in response to the requirements of D12(2)-(5). More extensive explanations are provided in our CPP164 Project Summary document.

Identified programme (CPP164) – corporate systems opex

D12(2) – (5)	**Explanation**
(2)(a)(i) description including aims and objectives	This programme covers the operating component of our corporate information systems, data and personal communications, productivity software and physical computer infrastructure. It also includes the direct costs of the information solutions group staff Services included in this category include: • the maintenance of out-of-warranty hardware • printer consumables and printer operations • fixed and mobile communications operations (telephony) • software licences (20%, the remaining 80% is accounted for in capex) • software maintenance agreements • business analysis, IT related project management, contractor/vendor management, software development, infrastructure support and administration.

	The aims and objectives of this programme are: • the prudent management of costs related to information systems and infrastructure • the delivery of highly resilient computer infrastructure information systems that reflect the 24 x 7 x 365 nature of our business and that our business is a provider of critical infrastructure. The drivers for this programme are: • acknowledgement of the high level of dependence of the business on information systems • the requirements of Civil Defence Emergency Management Act 2002 • minimisation of issues that prevent the effective use of information systems.
(2)(a)(ii) deliverability	The management of computer infrastructure is done in house and the major risk to programme deliverability is the retirement or resignation of key personnel. We are currently focussed on developing a succession plan to ensure that any disruption caused by the loss of key personnel is minimised and effectively managed.
(2)(a)(iii) contingency factors	There are no contingency factors provided for in this opex category.
(2)(b) and (5) assumptions, obligations and step changes	**Corporate line-of-business systems and productivity software** Our corporate line-of-business systems and productivity software supports cross-organisational processes within Orion. This includes financial systems, employee management systems (e.g. HR, Payroll, Health and safety) and personal productivity software (desktop applications, email, web and document management). The costs in this section are largely related to 20% of the cost of software licenses. A portion of the software license is attributed to maintenance including patches and fixes as well as a small component that pays for support. The bulk of the license payment (80%) is regarded as a prepayment for future upgrades and therefore appears in the capex budgets. There are no significant step changes in costs during the review period. **Physical computer infrastructure** Our computer infrastructure hosts our information systems, maintains the connections between systems required for an integrated environment and provides the networks and devices for users' access to our information systems. It is our policy to own and manage computer infrastructure rather than outsource to third parties because of the critical nature of some of our information systems and the need for them to be continuously connected in real time to equipment on the electricity network. We have few maintenance agreements associated with hardware, typically choosing to manage maintenance ourselves or to ensure that equipment is current and within warranty. There are no significant step changes in costs during the review period.

	Information Solutions Information Solutions is an in-sourced service provider of all IT and business change-related activities. The group is comprised of a business change / software development section, an infrastructure section and a section dedicated to the administration of control systems. Salaries represent around 50% of overall costs in this component. Changes in this review period reflect the retirement of a number of key employees and our response to provide continuity of service.
(2)(c) and (3) forecasting methodology	Our expenditure forecast has been based on a budget prepared on a bottom-up basis during FY12. It assumes: • An increase of salaries of $290k due to a redundancy and three new employees coming on during the year. • A reduction of $40k in recoveries to capital projects as we expect that the software developers will not contribute to any capital projects during FY13. • An increase of $80k in consultancy costs due to the new software we are installing requiring more outside assistance to maintain and integrate with our systems. • An increase of $170k in the cost of licensing the PowerOn and GIS systems. These costs have been delayed following the installation of the systems as there is a period of 1-2 years following installation where no licensing fees are payable. • There is a significant decrease from FY14 onwards as we have changed the allocation of any systems which are solely related to network services. Thus the PowerOn and Foxbro software maintenance costs will be included with Load Management Systems (CPP121) and GIS will be included in the information solutions – control systems scheduled maintenance programme (CPP106) and information solutions – asset management systems replacement programme (CPP42).
(4) relevant policies	Our Project Summary document sets out all of the relevant policies and reports for this category of opex

Our commercial opex is also included as an identified programme. The following information is provided in response to the requirements of D12(2)-(5). More extensive explanations are provided in our CPP165 Project Summary document.

Identified programme (CPP165) – commercial opex

D12(2) – (5)	Explanation
(2)(a)(i) description including aims and objectives	This team is responsible for billing, pricing, regulatory compliance and strategy and commercial matters. The Commercial team aims to: • ensure that Orion receives a fair rate of return on the fair value of its assets • ensure that Orion’s network delivery pricing and billing are well communicated, transparent, timely, accurate and compliant with price control requirements

	• ensure that Orion's demand side management signals have good take-up as appropriate • ensure that Transpower's charges are accurate • ensure that other charges (for example distributed generation) are accurate • ensure that key negotiations are well managed and conducted – for example new delivery services agreements and new investment agreements with Transpower • actively participate in the development of the regulatory regime – making considered submissions as appropriate • ensure compliance with regulatory and contractual requirements • understand regulatory impacts on Orion and the industry, and contribute to related initiatives • foster and effectively manage relationships with key stakeholders such as retailers, major customers, the Commission and the EA The Commercial team also provides broader commercial support to our business.
(2)(a)(ii) deliverability	Salaries and consultancy costs make up a large part of the Commercial team's opex. We have a very lean (1 FTE) regulatory team so we augment this with independent experts when required. For example, we have engaged expert legal and economic advice as part of our submissions on the development of Parts 4, 4A and 5 of the Commerce Act, and the subsequent price and quality control and information disclosure requirements. Specific independent advice is especially sought on specialist areas such as WACC.
(2)(a)(iii) contingency factors	There are no contingency factors provided for in this opex category.
(2)(b) and (5) assumptions, obligations and step changes	Commercial opex costs are relatively fixed from year-to-year. Overall, our forecasts assume that opex costs will remain relatively consistent in future years, with the Commercial team remaining at eight people over the forecast period. Remuneration for the team is forecast based on the FY12 cost for the CPP period. This represents approximately half of the forecast expenditure. Historically, two areas have seen material fluctuations in opex expenditure. First, 'communications' expenditure has been significant for the Commercial team and actual spend has been variable. This includes the company's annual report and other reports and sponsorships. From FY13 onwards, communications' is a separate business unit (refer CPP166). Second, 'consultancy' expenditure fluctuates depending on regulatory activity and our participation in it (for example submissions). For example: • In FY11, $950k was spent on consultancy. This especially involved extensive submissions on the Commerce Commission's draft input methodologies (IMs) • In FY12, $370k was spent on consultancy fees against a budget of $1m. Key reasons for a lower spend than expected was due to our focus on the earthquake recovery as well as our decision not to participate in the High Court merits review • In FY13, our expenditure is forecast to be significantly higher (up to $2m) as we prepare our CPP application and pay for the Commission's costs.

	Once our CPP application is complete and approved, we forecast that our consultancy spend in future years will be relatively stable, based on our view on the regulatory and industry landscape.
(2)(c) and (3) forecasting methodology	Our forecast was derived using FY12 as a base year. The step down in FY13 is due to the significant impact of the CPP proposal preparation which has resulted in some of our Commercial budget being assigned to special projects. Our CPP165 Project Summary Document explains more fully the linkages between our Commercial budget and CPP171 (special projects).
(4) relevant policies	Our Project Summary document sets out all of the relevant policies and reports for this category of opex

9.23.6 General management, administration and overheads opex – other

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The remaining general management, administration and overheads opex programmes are not selected as identified programmes. Explanations for all non scheduled corporate opex programmes are included in their Project Summary documents. There are no contingency factors provided for within these programmes.

A full list of these programmes is set out below.

General management, administration and overheads programmes (not included as an identified project)		
Reference	**Project Name**	**Description of activities covered by each programme**
CPP161	Finance	The finance programme comprises company secretariat and governance, SOI and business planning and budgeting, shareholder liaison, share register and company documentation, internal controls, financial and management accounting, financial accounting systems, tax compliance, statutory returns, regulatory information disclosures, financing, debt management, treasury, insurance management, legislative compliance, payroll, credit management, privacy systems and compliance, liaison with and support for auditors.
CPP166	Communications and engagement	The Communications and Engagement programme is focused on effective communication (both internal and external) and stakeholder engagement to ensure that Orion's consumers and other stakeholders are effectively notified, informed, engaged and consulted about Orion's purpose, activities and plans.
CPP168	Property maintenance	This programme covers the maintenance of the head office site(s)
CPP169	Insurance – material damage and business	This programme covers liability insurance policies (PC/PI/D&O), non liability insurance policies (material damage and business interruption) and broker fees

	interruption	
CPP170	Earthquakes – overheads/head office	This is a special programme where some abnormal earthquake associated corporate and management costs have been recorded.
CPP171	Special projects	This includes allowances for non recurring projects, such as regulatory price-quality resets and this CPP proposal process.

Appendix 21 also explains which of our policy documents are relevant to each of these programmes and how they were taken into account and complied with. We note that our network planning standards are not relevant to these programmes.

9.23.7 Insurance opex

IM D15

Our opex plan includes forecasts of insurance related opex, which are to be captured in the CPP price path. Schedule D15 requires information regarding any self-insurance allowance to address uninsured risks to be included in the CPP proposal. Orion has not included proposed self-insurance allowances in this proposal.

In the remainder of this section we discuss our approach to insurance. This is supported by:

- our insurance opex programme description (CPP169)
- an independent expert report prepared by Marsh on insurance of electricity distribution assets and Orion's approach to insurance (the Marsh Report) (included as Appendix 11).

Our approach to insurance

Our insurance opex includes:

- liability insurance policies – for example, directors and officers public liability, professional indemnity and statutory liability
- non liability insurance policies – for example, material damage (MD) and business interruption (BI)
- broker remuneration.

Orion, like other infrastructure entities, does not fully insure its network assets against catastrophic damage. Orion believes that its network has been and continues to be insured to the fullest extent that is economic to do so.

The last time Orion and the wider New Zealand industry were able to get full network catastrophe insurance was in 2001. In the 1990s electricity network companies were able to insure all of their electricity distribution networks for catastrophes under an industry catastrophe insurance scheme called the transmission and reticulation insurance programme (TRIP). Prior to TRIP all electricity distribution networks in New Zealand had been uninsured. Orion made, and was paid out for, two significant claims under TRIP – both claims were for damage to the network caused by storms. Global insurance underwriters effectively withdrew this TRIP cover in April 2001.

From April 2001, EDBs once again had no catastrophe cover for their networks. At that time Orion decided to insure the key substations and buildings at full replacement value under Orion's standard material damage insurance policy. It has been economic to do so for these particular assets.

Orion has not insured overhead lines and underground cables because it has been, and still is, uneconomic to do so. High minimum deductibles and very expensive premiums mean that EDBs in New Zealand, including Orion, have concluded that cover is not economic even if it is available. Based on an asset replacement value for our cables and lines of $1 billion, and even before the 22 February 2011 earthquake, our annual insurance premium for lines and cables alone was estimated to be around $100m if we chose to insure. This level of premium is clearly uneconomic.

The Marsh Report addresses the characteristics and evolution of insurance markets for transmission and distribution assets. It confirms that globally EDBs face the same insurance circumstances, that is: cables and lines risks are normally uninsured as insurance underwriters are not able to provide material damage (MD) and business interruption (BI) coverage for them. Cables and lines are specifically excluded from their reinsurance treaty arrangements.

The Marsh Report also states that in Marsh's experience, almost all network owners in the Australia and New Zealand region that they are involved in do not insure their transmission and distribution risks (they note one transmission exception). In Marsh's opinion our historical approach to insurance has been entirely appropriate, reasonable and consistent with that of other network companies in Australasia.

Catastrophic events

Over many years, we have worked hard to reduce the potential impacts of any catastrophes by designing resiliency and diversity into the network – for example using multiple routes and interconnections into each area in Christchurch. This is explained more fully in Sections 3.2.3 and 6.2.3 of this proposal.

A CPP in response to a catastrophic event enables us to seek to recover costs which were not anticipated in our current prices. Accordingly, in this CPP application we seek to recover the costs and forgone revenues resulting from the earthquakes experienced since 2010, to the extent that these were not insurable. Where some costs were insured, any insurance proceeds are deducted from our proposed CPP price path. This is described more fully in Section 7.3.7.

We note that this is consistent with provisions in other regulatory jurisdictions for ex-post cost recovery of unforeseen and uninsurable costs as a result of a catastrophic event (refer Appendix 10).

We have made no allowance in our CPP proposal for unanticipated costs associated with any future catastrophic event. We have no self insurance allowance in our opex forecast. If such an event should occur within the CPP regulatory period, we may seek to reopen this CPP to address the impacts of any such event at that time.

Thus we propose an ex post approach to the recovery of the consequences of potential future disasters. This is the same as the ex post allowances that this CPP proposal addresses for the consequences of the 2010 and 2011 Canterbury earthquakes.

The costs of insurance

One feature of our proposed insurance opex is the substantial changes to the cost of insurance and the terms of the cover we are able to obtain, post earthquake. For example since the 2010 and 2011 earthquakes, our MD and BI insurers have:

- increased annual premiums by around 1,000% (from $0.2m on 1 October 2009 to $2.0m on 1 October 2012)
- introduced ‘per site’ deductibles for earthquakes for the first time for Orion (10% for post 1935 buildings and 15% for pre 1935 buildings)
- introduced a $100m annual cap for natural disaster related claims (previously effectively $300m)
- reduced our BI indemnity period from 18 to 12 months.

Our Project Summary document explains more fully how our insurance related opex forecasts have been derived.

9.24 Controllable opex

IM D16

Schedule D16 requires an explanation of the types of opex which the CPP applicant has included as forecast controllable opex, and the justification for this proposal.

Controllable opex is specified in relation to the Incremental Rolling Incentive Scheme (IRIS) component of the CPP IMs. IRIS aims to promote efficiency improvements by mitigating any perverse incentives which can exist within a regulatory period. These can arise because a supplier may retain any efficiency benefits achieved within a regulatory period and in principle, these are shared with consumers at the end of that period when prices are reset. Thus a supplier will achieve most benefit from efficiency gains in year one of a regulatory period. IRIS is designed to carry over efficiency benefits into the next regulatory period, to incentivise a supplier to strive for gains throughout a regulatory period.

The CPP IM accommodates IRIS by allowing a CPP application to propose components of opex which are deemed to be “controllable”. Any forecast opex included as controllable opex will be assessed, on an ex post basis, against actual opex and any gain or loss specified as a recoverable cost which may be recovered in the current and next regulatory period (for a maximum of five years).

We have considered the option of nominating opex as controllable opex for the purpose of this CPP proposal. Given the current uncertainties which face us (including the rebuild, future earthquakes and costing escalation) and the wider Canterbury community we do not believe it is appropriate to include this mechanism in this CPP proposal. We are not currently operating in a business as usual state. Our consumers and other stakeholders such as CERA are also not yet working in a stable environment. This makes our forecasting extremely difficult. In addition we don’t have an accurate baseline against which to assess our potential for efficiency improvements in opex.

While we support the aims of the IRIS mechanism, and while we continue to improve the way we run our business, and seek to achieve efficiencies in our cost structures we have not elected to include any opex as controllable opex for the purpose of this CPP proposal. We believe it is more important for our consumers that we ‘get the job done’ over the next five to seven years, rather than strive for some potentially ‘arbitrary’ efficiency gains.

9.25 Related parties

IM D17

9.25.1 Identity of related parties

As noted in Section 9.11 above, Connetics is a related party of Orion. Connetics undertakes network construction and emergency and scheduled maintenance activities for us and our process for tendering and letting these contracts is explained above.

The rationale for our outsourcing model is set out in Section 9.11 above.

9.25.2 Related party projects and programmes

The projects and programmes which are included in our regulatory templates, and for which Connetics has provided services, are presented in the following tables. These tables set out the value of services provided by Connetics for each type of maintenance and capital undertaken by them.

Nominal value of Opex undertaken by Connetics ($ million)

Project Name	CPP Policy Reference	FY08	FY09	FY10	FY11	FY12
Emergency Maintenance						
Overhead lines	CPP117	-	-	0.4	0.7	0.8
Underground cables	CPP118	-	-	0.2	2.6	10.7
Network assets	CPP119	-	-	0.2	2.3	0.9
Subtotal		**-**	**-**	**0.8**	**5.7**	**12.4**
Scheduled Maintenance						
Subtransmission overhead lines	CPP100	-	-	0.1	0.0	0.0
Overhead lines 11kV and 400V	CPP101	-	-	0.6	0.3	0.2
Earths	CPP102	-	-	0.1	0.1	0.1
Subtransmission underground cables	CPP103	-	-	1.5	1.0	0.0
Underground cables 11kV and 400V	CPP104	-	-	0.5	0.3	0.2
Mapping and asset storage	CPP105	-	-	0.3	0.3	0.3
Protection and pilots	CPP107	-	-	0.2	0.1	0.0
Transformers	CPP108	-	-	1.0	0.5	0.6
Buildings, grounds and substations	CPP109	-	-	0.1	0.1	0.1
Meters	CPP110	-	-	0.0	0.0	0.0
Switchgear	CPP112	-	-	1.1	0.3	0.2
Load management systems	CPP121	-	-	0.1	0.1	0.1
Distribution management systems	CPP123	-	-	0.2	0.1	0.1
Subtotal		**-**	**-**	**5.9**	**3.3**	**1.9**
Non-scheduled Maintenance						
Overhead lines	CPP113	-	-	0.5	0.3	0.3
Network assets	CPP114	-	-	0.6	0.5	0.4
Underground cables	CPP115	-	-	0.4	0.6	0.1
Buildings, grounds and substations	CPP116	-	-	0.1	0.1	0.0
Subtotal		**-**	**-**	**1.6**	**1.4**	**0.8**
Total		**10.6**	**11.6**	**8.2**	**10.3**	**15.1**

Nominal value of Capex undertaken by Connetics ($ million)

Project Name	CPP Policy Reference	FY10	FY11	FY12
Major capex				
Load management software	N/A	0.0	0.0	0.0
Urban & rural major projects - 66kV	N/A	1.1	0.9	0.7
Urban major projects - Earthquake emergency	N/A	-	-	0.1
Urban major projects - Hornby	N/A	0.2	-	-
Urban major projects - Bromley	N/A	-	-	0.2
Rural major projects - Weedons	N/A	-	-	0.0
Urban & rural major projects - Substations	N/A	1.5	0.6	6.2
Other capex				
Underground conversions	CPP50	1.3	1.8	3.6
Urban Reinforcement	CPP51	2.8	4.2	1.6
Rural Reinforcement	CPP52	1.2	0.2	1.2
Connections and Extensions	CPP53	1.3	2.2	1.8
Replacement				
Overhead lines subtransmission	CPP30	-	-	-
Overhead lines 11kV and 400V	CPP31	-	0.1	0.1
Underground cables 11kV and 400V	CPP32	1.4	1.2	0.9
Pilots and protection	CPP33	0.0	0.2	-
Control systems	CPP34	0.2	0.8	0.3
Load management systems	CPP35	-	-	-
Switchgear	CPP36	-	-	0.0
Transformers	CPP37	1.2	1.7	0.3
Substations	CPP38	0.0	0.1	0.1
Buildings and grounds	CPP39	0.3	0.0	0.2
Meters	CPP40	0.3	-	-
Underground cables subtransmission	CPP41	-	-	-
Asset management systems	CPP42	0.0	0.2	0.4
Distribution management system	CPP43	-	-	-
Total		**12.9**	**14.3**	**17.7**

Note: These major projects were completed prior to the CPP regulatory period

As described in Section 8.5.3 we have lost some of our detailed financial records and data for FY08 and FY09 and we have not been able to break this down to a project/programme level by source. However, the evidence and information we have presented here for FY10 onwards reflects the same contract and tendering processes we had in place for works undertaken by Connetics in FY08 and FY09.

This work was delivered under many different individual contracts. With the exception of emergency maintenance, all scheduled and non scheduled maintenance projects over $20,000 and all capital projects are competitively tendered and subject to a unique contract.

Maintenance work undertaken by Connetics for projects less than $20,000 is subject to the agreed rates set out in the scheduled works contract. These rates are only accepted, for projects over $5,000, once at least one set of competing prices are obtained. The contract is awarded on the basis of lowest conforming tender prices.

Contract dates and terms

Our non-scheduled contract with Connetics (prior to October 2012) was 2009/001E. It was negotiated in 2008. It was due to expire in March 2011 – but due to the earthquakes, was extended until the new combination (emergency and scheduled works) contracts were re-negotiated.

Our previous emergency response with Connetics was known as 2007/073E. This contract was negotiated in 2006 and was also due to expire March 2011 - but due to the earthquakes, it was extended until new combined contracts were formalised.

A new combined contract for Connetics was finalised in October 2012, for a term of three years expiring in September 2015. There is a possibility of a two year extension, subject to satisfactory performance reviews.

Relevant contract terms which explain the nature of the services to be provided under this contract are included as Appendix 31.

9.25.3 Tendering processes

Our contract and tendering processes are set out in the following policies:

- NW73.10.07 Contract - Administration
- NW73.10.13 Contract - Evaluation of Tenders
- NW73.00.03 Contract - Management
- NW73.00.01 Contract - Standard Document
- NW73.00.02 Contract - Standard Procedure
- NW73.10.09 Contract - Tender Procedures
- NW73.10.15 Contractors - Authorised and Approved List
- NW73.10.10 Pricing Request

Our standard tendering process (as described in NW73.10.09) is set out below:

- prepare tender documents
- call for tenders
- close tenders
- evaluate tenders
- accept tender
- notify all tenderers.

All scheduled and non scheduled maintenance and capital works over the estimated value of $20,000 per project which has been undertaken by Connetics since FY08, has been awarded following this tendering process. The process for tendering and negotiating the new combined services contract is described above in Section 9.19. Copies of relevant policies and procedures are included in Appendix 32.

Supporting material

Schedule D17 of the IMs requires us to identify all relevant documents used to tender for the services provided by related parties. These include:

- our combined services contract pertaining to emergency and non scheduled maintenance projects
- the contract and tendering policies outlined above pertaining to capital and scheduled maintenance projects
- a schedule of all jobs issued to Connetics over the current period
- the contracts identified in that schedule pertaining to each works order issued for each job.

9.26 Project cost escalation

IM D18

We have prepared our opex and capex forecasts in real (FY13) terms. This is consistent with our annual AMP and budgeting processes. Since CPP expenditure allowances are specified in nominal terms, we escalate and inflate our real forecasts to derive nominal forecasts. In order to do this we have developed forecasts of opex and capex input cost inflation.

Our approach is to separate our expected costs into a number of groups, identify an escalation index for each cost group which represents a good proxy for expected movements in the unit costs for that group, and then forecast these indices for the CPP regulatory period. Using a general forecast inflation index, such as CPI, is not appropriate for all of our cost categories, since movements over time in our input costs can be quite different from movements in CPI.

In developing the details of our cost escalation approach, we have considered:

- how to disaggregate our costs
- has to escalate (index) each cost group
- how to forecast these indices.

Our costs can be split into any number of categories. The benefit of disaggregation is that movements in elements of total costs (for example between labour and materials costs) can be modelled explicitly through more specific and targeted indices. However, this comes at the cost of greater complexity and the challenge in finding suitable and available forecast indices.

9.26.1 Approaches adopted elsewhere

In developing our approach we first examined approaches adopted in other regulatory jurisdictions for similar purposes. The approaches we considered are summarised below.

Ofwat

Ofwat, the regulator of English and Welsh water companies, uses a relatively simple approach to determine costs for real price escalation purposes for regulated water businesses. Ofwat splits costs into opex and capex. All real opex is inflated using RPI (the UK index of general inflation). All real capex is inflated using a general construction output price index. Since this is an output price index (rather than an input price index), it implicitly accounts for the range of inputs to capex such as labour and materials.

Ofgem

Ofgem, the regulator of UK electricity distributors, uses a more detailed approach to determine costs for real price escalation purposes. Ofgem splits opex into four groups, and capex into six groups comprising:

- general labour (opex and capex)
- specialised labour (opex and capex)
- general materials (opex and capex)
- specialised materials (capex)
- equipment and plant (capex)
- other (opex and capex).

The weightings for each group are based on average industry weightings. Ofgem uses a different index for each group, respectively: general average earnings index (with and without a premium for specialised labour); resource cost index; electricity materials cost index; producer price index for electrical machinery and apparatus; and RPI.

AER

The Australian Energy Regulator (AER) uses a more detailed approach to determine costs for real price escalation purposes for its regulatory decisions. The AER splits each of opex and capex into labour and materials components, using distributor-specific weights. It treats opex and capex in the same way, although the weights between the labour and materials components differ.

For labour, the AER uses a general labour price index to inflate real costs. For materials, the AER develops a trade-weighted index for each distributor based on the underlying prices of key material components which include: aluminium; copper; steel; crude oil; and construction. The AER uses distributor specific weights for each component within total materials costs.

For aluminium, copper, steel and crude oil, the AER uses international market prices and exchange rates to develop an AUD index for the components. It uses commodity price and exchange rate forecasts to develop its forecast indices. For construction prices, the AER develops an index for local construction costs using available data.

Commerce Commission DPP Reset

The Commission has used a relatively simple approach to determine price escalators in its [draft] DPP Reset Determination for EDBs. Relative to the three international approaches described above, it falls between the Ofwat and Ofgem approaches in terms of level of detail.

For the purpose of the DPP Reset Determination, opex is disaggregated into labour and non-labour costs, and capex is treated as one group. For opex, real labour costs are escalated using the general labour cost index (LCI), and non-labour costs using the general producers price index (PPI). For capex, all real capex is escalated using the general capital goods price index (CGPI).

9.26.2 CPP considerations

The relatively simple approach proposed by the Commission for the DPP is consistent with the intent for the DPP to be a relatively low cost regulatory mechanism. Accordingly, a number of simplifying assumptions have been adopted for the DPP reset.

The CPP however is not so constrained and the CPP IMs provide for applicants to propose their own approach to cost escalation. The CPP IM anticipates that EDBs may use a more detailed approach than that outlined above for the DPP reset.

In our CPP proposal we have determined our opex and capex forecasts consistent with the expenditure objective as set out in Section 9.11.1. Accordingly our escalation method reflects our best forecasts of the cost escalations we will face over the CPP regulatory period. This is influenced by the post earthquake construction activity which is already evident, and local supply pressures are expected to increase over the next few years.

9.26.3 Our approach to cost categorisation

We have split each of our forecast opex and capex projects and programmes into the following three cost groups:

- labour
- materials
- other.

Each project and programme has a different weighting reflecting the characteristics of the work to be undertaken. For example, support opex has a relatively high proportion of labour costs, whereas major project capex has a relatively high proportion of materials costs.

Within the materials component of our network capex projects, we have also assigned a further level of disaggregation which reflects input costs for key asset groups. These asset groups comprise:

- 66kV underground cables
- 11kV and 400V underground cables
- overhead lines
- switchgear
- transformers.

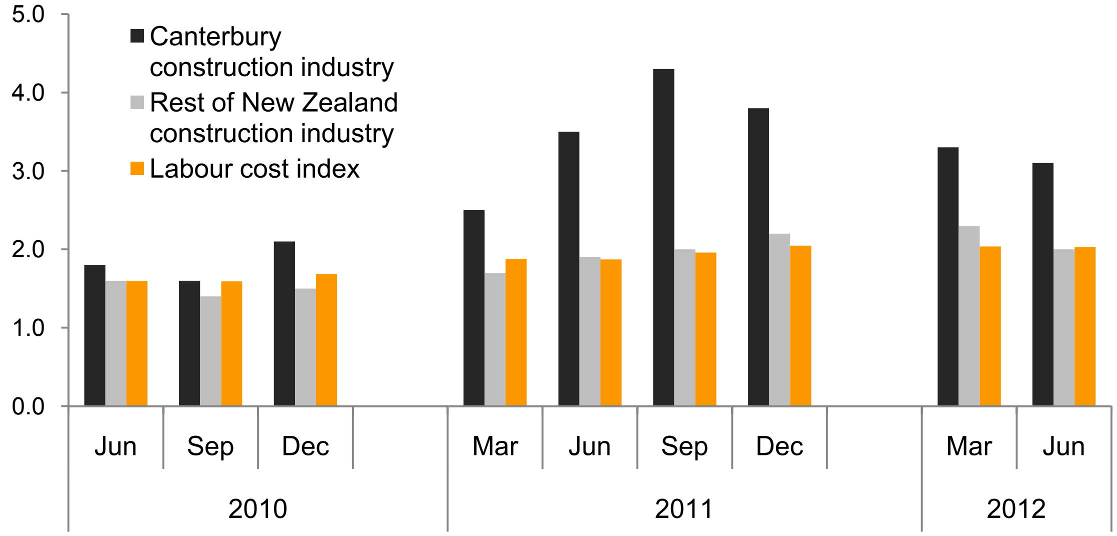
Materials are the most significant for our network related capex, and we expect price inflation for different types of materials to vary. It is not possible to disaggregate our network opex programmes in the same way, as opex predominantly comprises labour costs and incidental material items or asset components, not entire assets.

9.26.4 Our input price indices

Labour

Our starting position for deriving labour cost indices has been the Statistics NZ LCI. This is a general index of labour costs across New Zealand for which independent forecasts are readily available. We have also considered the impact of the Canterbury rebuild on expected labour costs in our region. Statistics NZ has recently introduced new indices to measure the changes to salary and wage rates in the Canterbury construction industry for this reason. There are no Statistics NZ forecasts available for these regional indices.

Statistics NZ - labour cost indices (% change from same quarter of previous year)



Local labour cost pressure is evident in our most recent contract tenders. We are starting to see increased labour costs come through into the market prices we are obtaining for our tendered contract work.

Our Dallington to McFaddens 66kV cable project, required to reinforce the Dallington zone substation, is a significant project in FY13. Actual costs to date are $8.2m with projected completion costs of $14.1m. This is forecast to be $1.7m over budget. Of this, $0.7m is associated with a slightly longer route length than originally planned. With projects this size we would normally have a much longer lead time to scope the project more accurately. This has not been the case due to the need to rapidly recover from and reduce our risk from the recent earthquake damage in this area of our network.

However, the costs associated with the proposed contract with SCIRT for installation are $1m higher than budget. This reflects a 44% increase in civil construction costs than originally estimated. This demonstrates how quickly the construction environment is changing as the rebuild starts to gather momentum.

We have therefore determined that it is not appropriate to apply the standard New Zealand wide LCI index to all components of our labour costs. We have determined that, as a minimum, a local index is required for our forecast field work labour costs (network related capex and opex). We have sought external assistance to help us determine an appropriate index basis for this purpose.

Rider Levett Bucknall and Davis Langdon are both quantity surveyor firms that work locally in Canterbury. We asked both firms to provide us with their estimates of annual escalation factors applicable for construction labour in the Canterbury region (included as appendices 33 and 34 respectively). This was an extremely challenging request, given the uncertainties in this market and the wider Christchurch/Canterbury rebuild.

Both quantity survey firms estimate 5% per annum in the longer term. David Langdon estimates 10% per annum over the next three years (FY14 to FY16), while Rider Levett Bucknall indicates using 5% per annum for the foreseeable future for its own estimating purposes.

Our proposed index reflects the mid-point of the two quantity surveyor estimates. We have assumed annual escalation of 7.5% for three years FY14 to FY16, and 5% per annum for FY17 to FY19. This is applied to network project and programme labour costs.

Subsequent to determining our Canterbury labour cost index we received an estimate from another local quantity survey firm, Ian Harrison & Associates (included as Appendix 35). This estimate was consistent with the others, in that it confirmed that we should expect to see higher rates of change for the foreseeable future than we had historically. However, Ian Harrison & Associates estimates of the annual percentage increases were somewhat higher than the other two sources. Accordingly we decided to adopt a conservative approach by retaining our original estimate, derived from the David Langdon and Rider Levett Bucknall estimates.

We expect that more data will become available in the future, which will allow labour cost forecasts to be more robust, but the CPP process does not allow us to accommodate future evidence. Given this uncertainty, we believe it is prudent to exclude the Ian Harrison & Associates forecast which is somewhat of an outlier when compared to the other two

We have retained the New Zealand wide LCI as an appropriate index for the labour component of our support functions (corporate and network management and operations). We do not have robust evidence available to us to form the basis of an alternative local approach for this component of our labour costs.

Materials

In order to create materials input cost escalators for each of the five asset groups included in our network capex, we have considered the most relevant input components for each asset group. As each asset group may contain a mix of asset types we have used weightings which reflect the asset components which we expect to construct over the CPP regulatory period. We created indices for each asset category based on the input cost weightings outlined in the following table, for the purpose of escalating capex costs.

Materials indices weightings – for capex projects

Asset component	Weighting	
66kV underground cables	Copper	100%
Other underground cables	Aluminium	95%
	Copper	5%
Overhead line conductors	Aluminium	95%
	Copper	5%
Transformers	Steel	45%
	Copper	50%
	Oil	5%
Switchgear	Copper	75%
	Steel	25%

Given the different nature of the material components which are reflected in maintenance (much smaller components of an incremental nature such as cross arms and insulators and consumables) we have used the DPP reset approach for opex materials. Thus we have used the general PPI input price index.

Other

For non-material or labour cost components we have used PPI as the cost escalator. This is applied to small proportions of capex projects or programmes where no practical alternative exists.

Other contingencies or allowances

We have included no other contingencies or allowances in our cost escalators.

9.26.5 Our forecast indices

We have used independent sources to generate the forecasts of all of our indices. The following table describes each index and its source.

Index source

Index	Forecast source	Date
Labour:		
- LCI	NZIER quarterly predictions	September 2012
- Canterbury construction	Composite index derived using Rider Levett Bucknall and Davis Langdon estimates	October 2012
Materials:		
- PPI	NZIER quarterly predictions	September 2012
- Copper	World Bank commodity price forecasts	September 2012
- Aluminium	World Bank commodity price forecasts	September 2012
- Steel (iron ore)	World Bank commodity price forecasts	September 2012
- Oil	World Bank commodity price forecasts	September 2012
Other		
- PPI	NZIER quarterly predictions	September 2012
Exchange rate		
- NZD/USD	NZIER quarterly predictions	September 2012

For PPI and LCI we use NZIER forecasts. NZIER produces quarterly forecasts of the Statistics NZ PPI and LCI. In our view the NZIER forecasts are at least as well-regarded as any other forecasts of these indices, and they are applied in the DPP Reset Determination.

We have used World Bank commodity price forecasts for the prices of copper, aluminium, iron ore (the major component of steel) and crude oil. The World Bank produces quarterly 10 year forecasts of major commodity prices. These forecasts are an average of the twelve months ending in December and are denominated in USD. We have adjusted the World Bank forecasts to the financial year ending 31 March and converted the prices to NZD. We have used the most recent NZIER NZD/USD exchange rate forecast for this purpose.

For each series, we use average values over the financial year. This is consistent with the approach adopted in the DPP Reset Determination and approximately reflects the ‘throughout the year’ nature of opex and capex.

Commodity price forecast (Nominal USD)	Assessment Period		CPP Period				
	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Crude oil ($/bbl)	106	107	107	107	107	108	108
Aluminium ($/mt)	2,350	2,500	2,600	2,650	2,700	2,725	2,750
Copper ($/mt)	8,500	8,000	7,000	6,500	6,000	6,100	6,200
Iron ore ($/dmt)	135	120	110	100	90	95	100

Source: World Bank, Development Prospects Group, September 2012

Extrapolation to the end of the CPP regulatory period

NZIER LCI and PPI forecasts are available for a period of approximately five years in advance – currently out to the end of FY17. RBNZ inflation forecasts are available for a period of approximately three years in advance – currently out to the middle of calendar year 2015.

We have extrapolated the RBNZ and NZIER forecasts out to the end of the CPP regulatory period. We have assumed that the last available annual growth rate will continue for the remainder of the CPP regulatory period.

NZIER exchange rate forecasts are available until the middle of calendar year 2016. We have extrapolated this to the end of the CPP regulatory period by assuming that the last available annual exchange rate forecast will continue to the end of the CPP regulatory period.

The table below shows our forecasts of LCI, PPI and NZD commodity prices indexed to FY13. The indices are based on average annual price change and for those sources from the World Bank, reflect the conversion to NZD using the NZD/USD assumptions included in the table. The projected devaluation of the NZD against the USD is instrumental in forecasts of real price decreases (in NZD terms) for some of the commodity prices over the CPP period.

Input price indices

Index	FY13	FY14	FY15	FY16	FY17	FY18	FY19
LCI	1.000	1.019	1.039	1.066	1.089	1.113	1.137
Canterbury construction labour	1.000	1.075	1.156	1.242	1.304	1.370	1.438
PPI	1.000	1.030	1.065	1.103	1.139	1.175	1.213
Aluminium	1.000	1.153	1.266	1.426	1.532	1.557	1.571
Copper	1.000	1.049	1.007	0.973	0.951	0.899	0.914
Iron ore	1.000	1.019	0.948	0.944	0.902	0.845	0.891
Crude Oil	1.000	1.010	1.055	1.153	1.218	1.221	1.224
NZD/USD applied in commodity indices	0.787	0.780	0.752	0.690	0.655	0.655	0.655

These indices can also be represented as annual percentage changes. As illustrated below.

Percentage change in input price indices

Index	FY13	FY14	FY15	FY16	FY17	FY18	FY19
LCI		1.92%	1.97%	2.61%	2.16%	2.16%	2.16%
Canterbury construction labour		7.50%	7.50%	7.50%	5.00%	5.00%	5.00%
PPI		3.04%	3.32%	3.65%	3.20%	3.20%	3.20%
Aluminium		15.27%	9.80%	12.70%	7.37%	1.64%	0.92%
Copper		4.85%	-3.92%	-3.37%	-2.31%	-5.49%	1.66%
Iron ore		1.95%	-7.05%	-0.34%	-4.45%	-6.41%	5.48%
Crude Oil		1.02%	4.44%	9.31%	5.62%	0.21%	0.26%
NZD/USD applied in commodity indices		-0.78%	-3.68%	-8.20%	-5.08%	0.00%	0.00%

Using the above indices and the weightings for each asset category we derived the following indices for each asset category for the purpose of the materials component of network capex. Thus we are able to apply multiple cost escalators to individual asset or expenditure types using the asset category weighting outlined above. This creates a more accurate nominal forecast, reflecting the different cost components of asset or expenditure types.

Input price indices for capex assets (material components)

Index	FY13	FY14	FY15	FY16	FY17	FY18	FY19
66kV underground cables	1.000	1.049	1.007	0.973	0.951	0.899	0.914
11kV and 400V underground cables	1.000	1.147	1.253	1.404	1.503	1.524	1.538
Overhead lines	1.000	1.147	1.253	1.404	1.503	1.524	1.538
Transformers	1.000	1.034	0.983	0.969	0.942	0.890	0.919
Switchgear	1.000	1.041	0.992	0.966	0.939	0.885	0.908

Percentage change in input price indices for capex assets (material components)

Index	FY13	FY14	FY15	FY16	FY17	FY18	FY19
66kV underground cables		4.85%	-3.92%	-3.37%	-2.31%	-5.49%	1.66%
11kV and 400V underground cables		14.75%	9.18%	12.06%	7.03%	1.42%	0.95%
Overhead lines		14.75%	9.18%	12.06%	7.03%	1.42%	0.95%
Transformers		3.36%	-4.90%	-1.38%	-2.78%	-5.52%	3.19%
Switchgear		4.13%	-4.69%	-2.65%	-2.83%	-5.71%	2.57%

9.26.6 Impact of escalators

The Schedule E template for cost indices demonstrates the relevance of each escalator to our capex and opex forecasts. The following tables summarise this information. Note this data excludes the value of assets to be acquired from Transpower (which are not subject to escalation).

Nominal capex summary by input cost esclator ($000s)

Index	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Labour (Canterbury construction)	23,339	40,370	42,075	38,139	34,065	37,843	28,920
Labour (LCI)	-	-	-	-	-	-	-
Materials - 66 kV underground cables	3,041	12,710	7,384	5,599	930	-	-
Materials - Other underground cables	5,080	8,416	9,215	8,452	8,521	7,595	7,100
Materials - Overhead lines	2,108	2,512	3,004	4,200	3,517	4,957	4,642
Materials - Transformers	3,247	6,963	6,058	4,533	7,224	6,545	4,096
Materials - Switchgear	9,289	10,035	13,343	10,373	11,896	12,914	9,876
Other	27,274	12,544	8,845	11,485	7,504	9,965	7,288
Total	**73,379**	**93,552**	**89,923**	**82,781**	**73,656**	**79,820**	**61,920**

Nominal opex summary by input cost esclator ($000s)							
Index	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Labour (Canterbury construction)	16,215	19,169	21,386	23,637	22,627	23,361	24,557
Labour (LCI)	17,900	19,937	20,731	21,381	21,976	22,284	22,828
Non-labour (PPI)	20,525	19,647	19,089	20,224	20,282	20,774	22,467
Total	**54,640**	**58,753**	**61,205**	**65,242**	**64,884**	**66,419**	**69,852**

Labour, which is escalated using our Canterbury construction index, comprises about 45% of our nominal capex forecast. Of the remainder, approximately 15% is switchgear, 9% distribution and LV cables and 6% underground cables. These are escalated using the relevant weighted commodity indices set out in 9.26.5.

Materials, which are escalated using a forecast of the PPI, comprise about one third of our nominal opex forecast. Of the remainder, approximately another third is labour associated with our maintenance activities (which we have escalated using our Canterbury labour index). The remaining third is office based labour, which we have escalated using forecast LCI.

9.27 Appendices and supporting documents

Section 9 – Appendices	
Appendix	**Title**
6	Subtransmission architecture review
7	11kV architecture review
8	Cable testing report (Wire Scan)
11	Marsh report on insurance
21	Summary of policies
22	Consultants' reports
23	References to AMP
24	Asset Management Policy
25	DSA (extract)
26	Detailed schedule of asset values
27	Construction cost benchmarks
28	EDB opex benchmarks
29	Current security gaps

30	Letter from CCC re undergrounding
31	Emergency maintenance contract terms
32	Contracting policies and procedures
33	Rider Levett Bucknall QS estimates
34	David Langdon QS estimates
35	Ian Harrison and Associates QS estimates
36	Project summary documents for each identified project
37	Asset management reports in support of identified projects

Section 9 – Supporting documentation
Description
Project Summary Documents for each non identified project
Policies, standards, specifications (listed in NW 70.50.03)
EAT CBRM report, March 2012
EAT AMMAT report, October 2012
MWH environmental footprint report, 2009
DSA
Asset management reports (NW70.00.22 – NW70.00.44)
Kestral Group Independent review of Orion's earthquake response
PwC and SKM for the ENA, 2010 ODV Handbook
2012 AMP
National Code of Practice for Utility Operators to Transport Corridors
NW73.10.07 Contract - Administration
NW73.10.13 Contract - Evaluation of Tenders
NW73.00.03 Contract - Management
NW73.00.01 Contract - Standard Document
NW73.00.02 Contract - Standard Procedure

NW73.10.09 Contract - Tender Procedures
NW73.10.15 Contractors - Authorised and Approved List
NW73.10.10 Pricing Request
Connetics combined services contract, October 2012
Schedule of capital and scheduled maintenance jobs issued to Connetics over current period and related contracts

Glossary and abbreviations

Glossary and abbreviations

Glossary	
Abbreviation or Term	**Definition**
αSAIDI	The average of the natural logarithm (ln) of each daily SAIDI Value in the non-zero dataset
αSAIFI	The average of the natural logarithm (ln) of each daily SAIFI Value in the non-zero dataset
βSAIDI	The standard deviation of the natural logarithm (ln) of each daily SAIDI Value in the non-zero dataset
βSAIFI	The standard deviation of the natural logarithm (ln) of each daily SAIFI Value in the non-zero dataset
µSAIDI	Average annual SAIDI in a normalised reference dataset
µSAIFI	Average annual SAIFI in a normalised reference dataset
σSAIDI	Standard deviation of daily SAIDI values in a normalised reference dataset multiplied by the square-root of 365
σSAIFI	Standard deviation of daily SAIFI values in a normalised reference dataset multiplied by the square-root of 365
$m	Million dollars
Act	Part 4 of the Commerce Act 1986
AER	Australian Energy Regulator
AMMAT	Asset Management Maturity Assessment Tool
AMP	Asset Management Plan
Assessment Period	Two year period commencing 1 April 2012, ending 31 March 2014
AUD	Australian Dollar
BBAR	Building Blocks Allowable Revenue
BI	Business Interruption
CAIDI	Customer Average Interruption Duration Index
CAP	Clean Air Plan
Capex	Capital expenditure

CBM	Condition Based Maintenance
CBRM	Condition Based Risk Management
CCC	Christchurch City Council
CCDU	Christchurch Central Development Unit
CCHL	Christchurch City Holdings Limited
CDEM	Civil Defence Emergency Act
CERA	Canterbury Earthquake Recovery Authority
CGPI	Capital Goods Price Index
Clawback Period	Commences 4 September 2010, ending 31 March 2014
CoF	Consequence of Failure
Commission	Commerce Commission
CPI	Consumers Price Index
CPP	Customised Price-Quality Path
CPP IM	Customised Price-Quality Path Input Methodologies as set out in Part 5 of the Commerce Act (Electricity Distribution Services Input Methodologies) Determination 2010
CPP Period	Five year period commencing 1 April 2014, ending 31 March 2019
CRC	Canterbury Regional Council
Current Period	Five year period commencing 1 April 2007, ending 31 March 2012
Disclosure Year	Year Ended 31 March
DG	Distributed Generation
DMS	Distribution Management System
DPP	Default Price-Quality Path
DSA	Delivery Services Agreement
EA	Electricity Authority
EAT	EA Technology
ECAN	Environment Canterbury
EDB	Electricity Distribution Business

EECA	Energy Efficiency Conservation Authority
ENA	Electricity Networks Association
EQC	Earthquake Commission
GAAP	Generally Accepted Accounting Principles
GBA	Orion’s Independent Verifier, Geoff Brown and Associates
GEONET	A collaboration between the Institute of Geological and Nuclear Sciences and the Earthquake Commission
GIS	Geographic information system
GFC	Global Financial Crisis
GFN	Ground Fault Neutraliser
GWh	Gigawatt hour
GXP	Grid Exit Points
HI	Health Index
HILP	High Impact Low Probability
HV	High Voltage
ICP	Installation Connection Point
ID	Information Disclosure
IDR	Information Disclosure Requirements
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IM	Input Methodology or Input Methodologies, as set out in the Commerce Act (Electricity Distribution Services Input Methodologies) Determination 2010
IRIS	Incremental Rolling Incentive Scheme
Km	Kilometre
LCI	Labour Cost Index
MAR	Maximum Allowable Revenue
MD	Material Damage
MEA	Modern Equivalent Asset
MED	Major Event Day

MM	Modified Mercalli
MOBIE	Ministry of Business, Innovation and Employment
MOCHED	Major-Plant Outage Causing Huge Economic Damage
MSU	Magnefix Switch Unit
MUoSA	Model Use of System Agreement
MW	Megawatt
Next Period	Seven year period commencing 1 April 2012, ending 31 March 2019
NPV	Net Present Value
NZED	New Zealand Electricity Department
NZTA	New Zealand Transport Authority
OIC	Order in Council
Ofgem	Office of the Gas and Electricity Markets
Ofwat	Office of Water Services
OIS	Oil Insulated Switch
OMS	Outage Management System
Opex	Operating Expenditure
Orion	Orion New Zealand Limited
PDA	Personal Digital Assistants
PFC	Power Factor Correction
PoF	Probability of Failure
PowerOn	Orion’s Network Management System
PPI	Producers Price Index
PV	Present Value
PwC	PricewaterhouseCoopers
RAB	Regulatory Asset Base
RBNZ	Reserve Bank of New Zealand
RCM	Reliability Centred Maintenance
RFP	Request for Proposals

RMA	Resource Management Act
RMU	Ring Main Unit
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
$SAIDI_{ASSESS}$	SAIDI Assessed Value, the sum of the daily SAIDI Values in the Normalised Assessment Dataset for the Assessment Period
$SAIDI_{LIMIT}$	SAIDI Reliability Limit, the sum of µSAIDI and σSAIDI
SAIFI	System Average Interruption Frequency Index
$SAIFI_{ASSESS}$	SAIFI Assessed Value, the sum of the daily SAIFI Values in the Normalised Assessment Dataset for the Assessment Period
$SAIFI_{LIMIT}$	SAIFI Reliability Limit, the sum of µSAIFI and σSAIFI
SCADA	Supervisory Control and Data Acquisition Systems
SCIRT	Stronger Christchurch Infrastructure Rebuild Team
SDC	Selwyn District Council
SKM	Sinclair Knight Merz
SOI	Statement of Intent
SOSS	Security of Supply Standard
T&D	Transmission and Distribution
TF	Timing Factor
TF_{REV}	Timing Factor for Revenue
TF_{VCA}	Timing Factor for Commissioned Assets
TRIP	Transmission and Reticulation Insurance Programme
UDS	Urban Development Strategy
USI	Upper South Island
VOLL	Value of Lost Load
WACC	Weighted Average Cost of Capital
YTD	Year to Date