

Appendices for CPP Proposal

- 1 PwC Report on Catastrophic Event Cost Recovery
- 2 James Mellsop and Will Taylor of NERA Expert Report
- 3 Linetech Consulting Report on Proposed Reliability Standards
- 4 Satisfaction of CPP IM information requirements
- 5 Modifications to Schedule E templates
- 6 Sub-transmission network architecture review
- 7 11kV urban network architecture review
- 8 Wire Scan's Cable Testing Report
- 9 Detailed data tables for proposed quality standards
- 10 Regulatory decisions regarding catastrophic events
- 11 Marsh's Report on Orion's Network Catastrophe Insurance
- 12 Quantity growth trends
- 13 Detailed calculations for weighted average growth in quantities
- 14 SKM's Report on Initial RAB Adjustments
- 15 Depreciation by asset type
- 16 Engineer's Report on Non Standard Asset Lives
- 17 Recoverable costs – verifier
- 18 Recoverable costs – auditor
- 19 Recoverable costs – engineer
- 20 Project and programme schedule summary
- 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 Network security gap
- 30 Letter from CCC on undergrounding
- 31 Emergency maintenance contract terms (extract)
- 32 Contract procedures and policies
- 33 Rider Levett Bucknall estimates
- 34 Davis Langdon estimates
- 35 Ian Harrison and Associates estimates
- 36 Project summary documents for identified projects
- 37 Asset management reports supporting identified projects

Appendix 1

PwC Report on Catastrophic Event Cost Recovery



Mr. David Freeman-Greene
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17 December 2012

Dear Mr Freeman-Greene

Long-term incidence of cost recovery following a catastrophic event

1. Summary and implications of findings

Terms of reference

The purpose of this report is to respond to Orion's request for an expert report in the context of the costs it incurred with respect to recent earthquakes in the Canterbury region. Orion's request, dated 4 October 2012, specifically asked as follows:

We seek an expert report from you which addresses the fundamental question as to "who should pay" for these uninsurable costs and losses following a catastrophic event, in the context of our CPP proposal. We consider specific consideration of the claw-back (ie: ex post) and forecast (ex ante) nature of our CPP proposal is required.

In particular we require a report which considers the following:

- i. *The role of the Commerce Act, Part 4 Purpose Statement, including the tension between each of the subparts of the Purpose Statement and the asymmetric risks of under investment by EDBs*
- ii. *The role of the Part 4 IMs, including the approach to asset valuation and cost of capital and CPP specific processes and rules*
- iii. *The Part 4 and IM provisions for claw-back (section 52D and 53V) - including recoverable cost mechanisms (including the option for price smoothing beyond the CPP period), and the requirements to consider financial hardship and price shock*
- iv. *Whether claw-back should compensate for uninsurable and unanticipated lost revenue and extra costs caused by catastrophic events relative to DPP assumptions*
- v. *The respective role of DPPs and CPPs in meeting the Part 4 Purpose*

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- vi. *The Energy Companies Act, which requires Orion to operate as a successful business*
- vii. *Orion's approach to insurance (in light of the Marsh expert report)*
- viii. *Orion's ability to manage its financial flexibility and resiliency through a combination of revenue, borrowings and its shareholder distribution policy*
- ix. *The nature of Orion's unanticipated costs and losses – for example there is not a one to one relationship between Orion's extra costs and improvements in SAIDI/SAIFI performance and many of the unanticipated costs relate to security of supply rather than short term reliability performance.*
- x. *Orion's obligation to consult with its consumers and other stakeholders (for example ratepayers) about its CPP proposal.*
- xi. *The relevance of other determinations to Orion's CPP, including the proposed EDB DPP reset and Transpower's price resets*
- xii. *The relevance of the Commission's CPP determination for Orion, to the operation of Part 4 and the signals that will be sent to other regulated suppliers.*

I have interpreted the request as requiring me to address two questions:

- Where, considered over the long term, should the incidence of cost recovery lay between Orion and its consumers?
- Where costs are recovered from consumers, how should cost-recovery be spread over time?

My conclusions on each of these matters are as follows. It has been convenient to address the above matters in a different order to those discussed above; however, Appendix A indicates where each of these matters has been addressed in the report.

Long term incidence of cost recovery

- A key objective of price regulation is to protect consumers from the misuse of monopoly power, while ensuring the continued and reliable provision of the service. These apparently competing objectives are almost universally settled by setting prices that permit the recovery of prudent and efficient costs, including a commercial return on investment. These tensions are reflected directly in the Purpose Statement for Part 4 of the Commerce Act.
 - Catastrophic events raise the cost of providing a service and, equivalently, lead to a loss of revenue. Accordingly, my answer to the first question set out above is that, consistent with the treatment of costs in general, the efficient and prudent costs caused by catastrophic events should be recovered from consumers.



- The key choice that exists with respect to the recovery of the costs caused by catastrophic events lies in how the compensation for these costs (including lower revenues) should best be provided, with the options being:
 - An allowance (akin to self insurance) under which the regulated business gets an allowance every year based on a forecast about the frequency and consequences of such an event (but the supplier bears any windfall gain or loss associated with these forecasts being incorrect), or
 - Compensation for the actual costs incurred after the event has occurred.
- My view is that the latter regime (compensation after the event occurred) has substantial practical advantages over the former. It is also consistent with the assumptions built into the current price controls, and is clearly the approach that is assumed in the new Part 4 of the Commerce Act and in the Commerce Commission's Input Methodologies.
- I also note that:
 - Orion could expect to be asked to demonstrate the prudence and efficiency of its decisions prior to and after the event (although I note that this should focus on the prudence of decisions in the light of the information available at the time and so avoid applying undue hindsight). However, from the information I have reviewed, Orion would appear to be well placed to demonstrate that it was prudent in its preparations for, and response to, this event. For example, I am informed that Orion factored the prospect of earthquakes in to its network decisions, which it says delivered substantial, quantifiable benefits to itself and consumers after the earthquakes. I have also reviewed an expert report from Marsh that concluded that Orion's insurance decisions prior to the event were prudent and in line with good industry practice.
 - The fact that Orion is community owned does not alter these conclusions. The Energy Companies Act requires it to operate as a successful business, and resource efficiency generally is advanced if it sets prices that recover the full cost of service (which is the outcome achieved if prices are set as if it is privately owned). Moreover, the effect of the earthquake has been to raise the cost of providing electricity distribution services (through requiring repair and replacement of assets, loss of revenue, etc.), which would have been unaffected by who owns the assets.

Timing of cost recovery

- When considering the recovery of costs associated with a catastrophic event, there is a tension between ensuring prices provide a sufficient cash flow to fund the costs for the business and the risks of distorting the consumption decisions of consumers (i.e., discouraging otherwise efficient consumption).
 - For the avoidance of doubt, the full cost caused by the catastrophic event should be recovered from consumers. The issue considered in this section is how that



cost recovery should be spread over time in a NPV neutral manner so as to help mitigate the impact on consumers.

- The risk of reduced revenue from changes in consumer behaviour can be mitigated by extending, or delaying, the recovery of costs associated with a catastrophic event, and so seeking to avoid any short term “spike” in prices. There is, however, a natural limit to the extent cost recovery can be delayed or extended. This is because the business requires cash flow in order to fund its costs and to maintain the deepest and lowest forms of debt finance.
- I recommend that Orion and the Commerce Commission give explicit consideration to the need to minimise distorting customer consumption decisions while meeting the genuine cash flow needs of the business when setting a price path to recover these costs. In this regard, I note that:
 - While decisions will be made about the recovery period for each cost item (i.e., the various elements of claw-back, the recovery of the residual cost of damaged assets, recovery of new expenditure), it is the *aggregate* impact of the separate recoveries that matters for consumers as well as cash flow. The reasonableness of each separate recovery option should be tested against the impact on the overall result on consumers.
 - If the recovery of claw-back is to be spread over multiple regulatory periods (i.e., more than 5 years), the Commission should provide sufficient clarity about what approach it will take and the mechanisms it will use to do so in order to minimise any risk to Orion as to how amounts that remain unrecovered after the initial CPP will be treated in future controls.

Some implications of our conclusions

This section summarises the implications of the findings above for some of the questions that interested parties may have with Orion’s proposals. This is in recognition of Orion’s obligations when preparing a CPP application to consult with its stakeholders.

IS ORION PROPOSING A DIFFERENT TREATMENT TO FIRMS OPERATING IN COMPETITIVE MARKETS?

A pre-requisite for investment in any market – including the most vigorously competitive – is that the investor expects to make a commercial return on that investment after recovering efficient costs. These costs include those incurred as a result of catastrophic events, like major earthquakes. Against this objective, Orion’s proposal is wholly consistent with the outcome expected in any form of competitive market.

Where Orion’s proposed approach is different to the outcome expected in some forms of competitive market is in *when* those costs are recovered. Firms in the most vigorously competitive markets would not be able to pass on some of the additional costs caused by a catastrophic event after the event has occurred – specifically, only costs that are borne by a new competitor would be expected to be reflected in the market price, whereas the incumbent would bear additional costs (for example, the repair of damage to existing

assets).¹ As a result, firms in competitive markets insure against such losses and, where insurance is too costly or unavailable, add an increment to prices based on the “best guess” of the cost caused by such events (in turn reflecting the “best guesses” of the likelihood and consequence of future catastrophic events). In contrast, Orion is proposing to recover the cost after the event has occurred.

However, there are a number of reasons for treating Orion in this manner.

- First, the proportion of Orion’s exposure to such events that cannot be economically insured is much greater than for the typical firm in a competitive market, which the Marsh report discussed above notes is common to electricity distribution businesses in NZ and globally. Thus, while Orion insures just like firms in competitive markets, the uninsured “gap” is much more significant.
- Secondly, the fact that Orion is a monopoly and has its prices regulated means that there is the flexibility to include a much more accurate recovery of cost in its regulated charges than would occur in the competitive market discussed above. That is, rather than making the “best guess” about the effect of a future event – which brings with it the risk of overcharging as well as undercharging consumers – the actual cost can be recovered.
- Thirdly, a fair interpretation of history suggests that Orion (like other EDBs) had not been recovering through their charges the anticipated, uninsured “gap” in cost recovery prior to the earthquakes.

Moreover, in an alternative form of competitive market, such costs could be passed on to consumers after the event. The Commission has identified a market where competition exists at the time that long term contracts for infrastructure-like services are written. It would be possible and logical for such a contract to include a more certain treatment of the recovery of such costs.

However, if Orion expected to recover the actual cost caused by such an event after the event, then this could have dampened its incentive to be efficient. Thus, it is reasonable for consumers to expect Orion to demonstrate the prudence of its expenditure prior to and after the event.

SHOULD ORION EARN A COMMERCIAL RETURN FROM THE SUPPLY OF DISTRIBUTION SERVICES?

Orion’s regulated charges have been set such that a reasonable, commercial return would be expected to be earned on investment after efficient costs have been recovered. The allowable rate of return has been determined (by the Commission) on the basis of the return that would be available from an alternative investment and an adjustment for risk (electricity distributors are treated as a low risk business).

While Orion is a council-owned business, it is reasonable for it generate a commercial return from its investments. The reasons for this include the following.

¹ A catastrophic event will raise some costs for all competitors, which will be passed on to consumers after the event. As an example, the cost of insurance generally increases after such an event (and/or the coverage decreases).

- First, Orion is required by the Energy Companies Act to operate as successful business. A critical requirement for the success of any business – and for a capital intensive business in particular – is to make a commercial return.
- Secondly, Orion is an important investment of its owner-councils. The option has existed (in principle at least) for its owners to sell Orion to private interests and invest the proceeds in alternative investments, in which case a reasonable commercial return would have been earned. Allowing Orion to generate a commercial return provides for a neutral outcome for its owners against this alternative.
- Thirdly, including a commercial return in Orion's regulated prices results in those prices recovering the full cost of providing the service (the return that is foregone by not being able to invest in alternative, commercial activities is a key component of this cost). Setting cost-reflective prices encourages broader resource efficiency by encouraging consumers to consider the cost that society bears for the provision of the service when deciding whether and how to consume electricity.
- Fourthly, as Orion's owners are the councils whose areas are broadly, but not exactly, coincident with Orion's territory, the local population could be expected to ultimately pay for the additional costs borne by Orion, with the choice being whether this is direct (through electricity charges) or indirect (through higher council rates, being a consequence of reduced earnings for the councils from their investment in Orion). The former could be seen to be a fairer means of spreading the cost burden as it would mean that an individual's share would reflect its proportionate use of the electricity infrastructure.

I consider that Orion's proposed recovery of the costs caused by the earthquakes would be reasonable if Orion was privately owned. If Orion was privately owned, the character of the losses caused by the earthquakes would be the same.

2. Overview and background

This section sets out my understanding of the Terms of Reference provided to me by Orion. In addition, in order to inform the analysis of the issues, I set out some contextual information; namely relevant background information about Orion, and my understanding of some of the relevant consequences from recent earthquakes.

2.1. Scope of advice

The Terms of Reference from Orion has been provided in the context that it has incurred material costs associated with recent earthquakes and that it is planning to submit a customised price-quality path (CPP) associated with these costs. On this basis, I have interpreted the Terms of References as requiring me to address two key questions:

- Where, considered over the long term, should the incidence of cost recovery lay between Orion and its consumers?
- Where costs are recovered from consumers, how should cost-recovery be spread over time?

Orion has also identified a number of matters that I should have regard to when answering these questions. These relate predominately to the consideration of the regulatory framework Orion operates within, relevant statements by the Commerce Commission, the nature of the costs and losses it has incurred, and relevant actions of Orion prior to, and following, the catastrophic event. I have also been provided with a report from Marsh that assesses the prudence of Orion's insurance purchases prior to the earthquakes occurring.

2.2. About Orion

Orion owns and operates the electricity distribution network in central Canterbury between the Waimakariri and Rakaia rivers, and from the Canterbury coast to Arthur's Pass.

Orion is a community owned company. The Christchurch City Council owns 89 per cent of Orion and the Selwyn District Council owns the remaining 11 percent. This means that the consumers of Orion's services are effectively its shareholders.

While Orion is community owned, an important assumption in this report is that, for regulatory purposes, Orion should be treated the same as any other commercial entity. That is, it is assumed that it faces the same disciplines and pressures on returns as privately owned and financed entities. This assumption is based on my understanding that Orion is intended to operate as a fully commercial entity, and also based on my view that this would enhance the efficiency of service provision, which is addressed further in section 3.2.2.

2.3. Recent experience from earthquakes

Earthquakes on 4 September 2010 and 22 February 2011, in particular, caused extensive damage to the Orion distribution network. The damage and losses for Orion from the 22 February 2011 earthquake were an order of magnitude greater than for the previous earthquake.

There are three predominant impacts from the earthquakes for Orion:

- It damaged electricity network assets needed to supply electricity to consumers. Some of the assets could be repaired while others required replacement. I am advised by Orion that the cost of repairing these assets is expected to exceed NZ\$70 million.
- Energy consumption has fallen and, as a consequence, revenue has fallen, and usage is expected to remain at levels lower than it would have been without the earthquake for some time. The fall in energy consumption is largely due to residential, commercial and industrial consumers either moving away from the area or damage to their own premises and equipment constraining their capacity to consume electricity.
- It has changed the location of the customer base within the region and therefore the expected locations of growth. As a consequence, future capital expenditure is likely to be higher to meet demand than it otherwise would have been.

3. Allocation of the long-term incidence of costs

In this section I consider the question of where the long-term incidence of costs should lay following a catastrophic event. Principally, the decision is whether these costs should be borne by Orion or consumers.

I first set out the economic principles that are relevant to considering the long-term incidence of cost for a regulated electricity network business. I then consider the regulatory precedent and statements of the Commerce Commission as guidance on the approach that has actually applied for Orion. Having regard to Orion's actual behaviour prior to and following the earthquakes, I draw conclusions on where the incidence of costs should lay following a catastrophic event.

3.1. Relevant economic principles for the incidence of cost recovery

3.1.1. Importance of long term cost recovery

The purpose of economic regulation is to constrain the impact of the misuse of market power, but subject to the constraint that consumers place a high value on continued and reliable service provision, and therefore the simultaneous achievement of this outcome. This tension between investment (and service provision) while not allowing undue monopoly rents is reflected directly in the purpose statement for Part 4 of the Commerce Act,² most notably in factors (a) (incentive to innovate and invest) and (d) (suppliers limited in their ability to extract excessive profits).

The universal response by regulators (or at least those who deal with commercial entities in market economies) to these competing objectives is to set prices with reference to cost – that is, to ensure that businesses can expect to recover operating costs and at least make a commercial return on investment, thus eliminating monopoly rents and generating prices that are as low as is compatible with continued and reliable service provision. Indeed, it is common for a “safety margin” to be included in estimates of important inputs like the allowed return on investment in recognition that consumers would value additional confidence that a reliable and secure service will be provided.

I observe for completeness that the outcome whereby regulated businesses have a reasonable expectation that they will recover costs is not something that is unique to the regulated sector, but rather is an essential element for the long term sustainability of any business. 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. I note that the Commission has endorsed strongly the importance of the regime providing firms with the expectation of recovering efficient cost, noting the following for example:³

² Commerce Act, section 52A.

³ Commerce Commission, 2010, Input Methodologies Reasons Paper, December, p.36.

Investment (s 52A(1)(a)). In workably competitive markets, there is pressure on firms to undertake investments at an efficient level and at the socially optimal time. Superior investment decisions are rewarded by greater than normal returns (i.e. normal profits) in the short to medium term, and it is this prospect of earning above-normal returns for a period that provides incentives for efficient investment (and efficiency more generally). If a regulated firm does not expect to make at least a normal return on its efficient incremental investments going forward, it would be unable to maintain the quality of its services and would have no incentive to invest further in order to meet the growth in consumer demand.

3.1.2. Relevance of uncertain events

This also means that firms should be compensated, through prices to consumers, for any one-sided costs and risks they may face, such as those that arise from a catastrophic event.

It is also important to be clear about what costs are relevant. It is not just the easily observed costs of doing business that are important, such as recurrent operating expenditures and reasonably foreseeable capital expenditures. Cost recovery should also include compensation for the less easily observed and/or uncertain costs associated with the service. It is noted that all costs have a degree of uncertainty attached to them – and the only differentiating factor of those that are the subject of this report is the fact that (prior to the earthquake) they were less certain than normal expenses.

I note for completeness that there is no conceptual difference from a regulatory perspective between adverse events that cause a reduction in revenue (through reducing demand) and those that occur to cost. An unexpected (and uncompensated) event that leads to a reduction in anticipated revenue (arising from a reduction in demand) for a firm with largely fixed costs will result in costs being unrecovered, just like an unexpected (and uncompensated) increase in costs. In this report I refer a reduction in energy usage and consequent impact on anticipated revenue as an “expense” in order to keep the discussion as simple as possible; however, it is emphasised here that a proper treatment of changes to demand is equally important to a proper treatment of expenditure items.⁴

It is important here to appreciate the difference in what the regulatory WACC compensates for, the role of diversification in this regard, and how this relates to uncertain events.

- The cost of capital is the return that investors need to expect *on average* in order to be induced to hold a particular asset. A return equal to the cost of capital will compensate investors for the volatility of returns around this expected or average level. We know, however, that not all volatility affects the cost of capital – as a large portion of the risk can be eliminated at no cost merely by holding an asset as part of a diversified portfolio. Financial models like the Capital Asset Pricing Model are directed towards estimating the return required from a particular asset after taking account of such matters as the ability to diversify risk.

⁴ The reduction in revenue caused by the earthquake can be interpreted as akin to bad debts, which are typically recorded as expenditure items even though they relate to the non-receipt of anticipated revenue.

- A corollary of the above statement is that, when a regulator applies the regulatory WACC to derive regulated revenues, the resulting cash flows need to deliver an expected or average return equal to the WACC. This reference to expected or average returns means that the return needs to equate to the regulatory WACC after taking account of all of the possible future events that may occur, weighted by their probability of occurrence. If classes of costs are missed or ignored when setting regulated revenues, then the expected return will fall short of the regulatory WACC and the cost recovery discussed above will not occur.

Importantly, diversification by investors cannot reduce the effects of asymmetric events. Diversification is a technique that enables investors to reduce the risk premium required to invest in a particular asset, it cannot reduce the cost of physically running a business (that is, operating, maintaining and investing in an asset).⁵ It follows that the ability for investors to diversify cannot reduce the cost associated with uncertain events any more than it can reduce operating and maintenance costs.

When discussing uncertain events, it is common to distinguish between symmetric and asymmetric events. The former events bring with them the prospect of downside consequences, but also upside potential.⁶ The effect of these sorts of events can be ignored if it is reasonable to assume that the value of the downside and upside consequences are likely to offset approximately (which is the definition of symmetry). However, the effects of a catastrophic event like an earthquake provide a clear example of a one-sided liability. That is, an event that, if it occurs, would cause damage and cost, but not deliver a corresponding prospect of an upside reward.

The above principles have been well accepted in Australia for some time, being succinctly described in a regulatory decision over a decade ago:⁷

... the Office noted investors should not expect to earn a return for risk that is associated with events that are unique to a particular firm, given that this risk can be eliminated costlessly by holding a widely diversified portfolio of assets. However, it was accepted that the price controls should be designed such that investors can expect to earn the WACC on average, taking into account all potential events.

In addition, the Expert Panel that the Commission engaged to advise upon matters related to the cost of capital also endorsed the observations above that asymmetric events are not

⁵ The discussion above assumes that the appropriate compensation in respect of an uncertain event is to receive an allowance equal to the expected cost (also referred to as the actuarially fair cost) associated with the event. This allowance does not include a risk premium (the latter being the amount that is provided in addition to the actuarially fair cost) and so implicitly assumes that the required risk premium is already captured in the regulatory WACC.

⁶ An example may be the weather, with deviations from the average delivering either more or less revenue than would occur under average weather conditions.

⁷ Office of the Regulator-General, 2000, Electricity Distribution Price Review – Final Decision, September, pp.317-318.

naturally compensated through the regulatory WACC and that an additional compensation for these matters should be considered. The Panel commented that:⁸

All three Panel members agree that asymmetric risks are real, potentially have large impacts on the firm, and therefore should not be ignored by the Commission.

3.1.3. Options for ensuring long run cost recovery in the presence of uncertain events

There are two polar options for ensuring that the objective of long run cost recovery is maintained in the face of uncertain (and asymmetric) events, which are to:

- *Polar option 1:* Compensate the regulated business for the expected (actuarially fair) annual cost associated with such events (with this allowance occurring in advance of and subsequent to, such events),⁹ or
- *Polar option 2:* Wait for the relevant event to occur and then compensate the business for the costs that are caused.

Within these two options are the two key questions that arise with respect to these events, namely:

- Who takes the risk associated with the consequences of the event – that is, if the risk is smaller or larger than expected, or if the ex ante compensation has been insufficient or has been excessive, who bears the shortfall or keeps the surplus?
- Under either option, consumers will bear the cost, but when will this cost be incurred? Will the cost recovery be smoothed over time, with this recovery commencing before the event, or just commence after the event has occurred?

For the two polar cases, the answers to these questions are clear, namely that:

- *Polar option 1:* risk is transferred to the regulated business and cost recovery at least commences in advance of the event, as discussed above, and
- *Polar option 2:* risk is borne by consumers and recovery occurs after the event.

The outworking of the two options is illustrated in the stylised example below. In this example, it is assumed that:

- The business has an opening regulatory asset base (RAB) of 1000, which is fully recovered over the 5 year life of the asset
- The regulatory WACC is 10 per cent (pre tax)

⁸ Franks, J., Lally, M., Myers, S., Recommendations to the New Zealand Commerce Commission on an appropriate Cost of Capital Methodology, 18 December 2008, p. 37.

⁹ That is, if an event was expected to occur once every 40 years and have a cost of 100, then 2.5 would need to be provided per annum ($= 1/40 \times 100$). If the event did in fact only occur once in 40 years, then the regulated business would recover 100 per event and be properly compensated, ignoring the time value of money. If the event occurred in year 20, then the business would have recovered half of the cost prior to the event, and then the remainder subsequent to the event.



- The business occurs “certain” ongoing costs of 10 per annum, and
- There is a 5 per cent chance of an adverse event occurring in any one year that would cause a cost of 175, implying an actuarially fair cost associated with the uncertain event of 8.75 per annum.

[1] Year	PV	1	2	3	4	5
[2] <i>Regulated revenues if only "certain" costs are considered</i>						
[3] Regulated Revenues - capital		263.80	263.80	263.80	263.80	263.80
[4] Costs (certain)		10.00	10.00	10.00	10.00	10.00
[5] Regulated revenues - total		273.80	273.80	273.80	273.80	273.80
[6] Costs (certain)		10.00	10.00	10.00	10.00	10.00
[7] Expected cash flow	1,000.00	263.80	263.80	263.80	263.80	263.80
[8]						
[9] <i>But if there are uncertain (one-sided) costs</i>						
[10] Regulated Revenues - total		273.80	273.80	273.80	273.80	273.80
[11] Costs (certain)		10.00	10.00	10.00	10.00	10.00
[12] Costs (uncertain)		8.75	8.75	8.75	8.75	8.75
[13] Expected cash flow	966.83	255.05	255.05	255.05	255.05	255.05
[14]						
[15] <i>Response 1: Compensate for expected cost</i>						
[16] <i>Ex ante position</i>						
[17] Regulated revenues - capital		263.80	263.80	263.80	263.80	263.80
[18] Costs (certain)		10.00	10.00	10.00	10.00	10.00
[19] Costs (expected cost of uncertain events)		8.75	8.75	8.75	8.75	8.75
[20] Regulated revenues - total		282.55	282.55	282.55	282.55	282.55
[21] Certain cost		10.00	10.00	10.00	10.00	10.00
[22] Uncertain cost		8.75	8.75	8.75	8.75	8.75
[23] Expected cash flow	1,000.00	263.80	263.80	263.80	263.80	263.80
[24]						
[25] <i>Ex post position if event occurs</i>						
[26] Regulated revenues - total		282.55	282.55	282.55	282.55	282.55
[27] Certain costs		10.00	10.00	10.00	10.00	10.00
[28] Uncertain cost		-	-	175.00	-	-
[29] Actual cash flow	901.69	272.55	272.55	97.55	272.55	272.55
[30]						
[31] <i>Ex post position if event does not occur</i>						
[32] Regulated revenues - total		282.55	282.55	282.55	282.55	282.55
[33] Certain costs		10.00	10.00	10.00	10.00	10.00
[34] Uncertain cost		-	-	-	-	-
[35] Actual cash flow	1,033.17	272.55	272.55	272.55	272.55	272.55
[36]						
[37] <i>Response 2: Take away risk and compensate if the uncertain event occurs</i>						
[38] Regulated revenues - capital		263.80	263.80	263.80	263.80	263.80
[39] Costs (certain)		10.00	10.00	10.00	10.00	10.00
[40] Costs (uncertain)		-	-	175.00	-	-
[41] Regulated revenues - total		273.80	273.80	448.80	273.80	273.80
[42] Costs (certain)		10.00	10.00	10.00	10.00	10.00
[43] Costs (after uncertain event occurs)		-	-	175.00	-	-
[44] Expected cash flow	1,000.00	263.80	263.80	263.80	263.80	263.80

The messages from this example are as follows:

- If uncertain costs are ignored when setting regulated revenues, but these exist, then the regulated business will be undercompensated (rows 9 to 13). While the regulator



will think it is providing cash flows with a present value of 1000 (and so NPV = 0, row 7), the cash flow in fact has a present value of 966.83 (NPV = -33.17, row 13).

- The two options for remedying this issue are either to compensate in advance for the expected cost (rows 15 to 23) or compensate if the event occurs (rows 37 to 44). However, this example also points to potential issues with the options, namely that:
 - with ex ante compensation, the prospect exists that the regulated business will be undercompensated for the risk (rows 25 to 29) or overcompensated (rows 31 to 35), depending upon the accuracy of the forecasts that fed into the ex ante allowance, and
 - with ex post recovery, a material cost will be incurred (and recoverable from consumers) if the event occurs – raising the question of how this should be spread over time.
- A further implication of the last point is that both options will deliver the same outcomes for the regulated business and consumers if the ex ante allowance is calculated using the “true” frequency and consequences of the catastrophic event. That is, the expected or average payoff to the business and consumers should be the same under either approach – where they differ is in who bears the risk if the ex ante allowance is incorrect.¹⁰

The relative merits of the alternative options are addressed in more length in Section 3.2.2.

It is noted here that a myriad of options exist between the two polar options discussed above for how the two questions posed above could be answered. Two that will be mentioned here are that:

- there could be cost recovery from consumers in advance of an event occurring, but a true-up at the time of the event to account for the difference between the actual cost and the amount recovered – in effect, advance recovery without the risk transfer, or
- a risk transfer for some of the consequences associated with an event, but not all.

As implied by the last point, a key requirement for a model based on risk transfer to result in cost recovery but without inappropriate monopoly rents being earned is for the bounds of that transfer of risk to be clearly established up front (that is, prior to an event occurring), together with the provision of the appropriate compensation. Once an event has occurred, the regulated business will have a strong incentive to argue for its exposure to be read narrowly, while consumers will have the incentive to advocate the opposite. Indeed, this is one of the key shortcomings of a model that incorporates risk transfer, which is discussed further in Section 3.2.2.

3.1.4. Relevant questions in relation to Orion

As the earthquakes have now occurred, the most directly relevant question is what was assumed about the allocation of risk associated with natural disasters in the current regime

¹⁰ The difficulties of getting an ex ante allowance correct – reflecting the difficulties of accurately predicting the frequency and consequences of such events – are immense, however.

and, related to this, whether there has been some form of pre-recovery from consumers that should now be taken into account. This is a factual question, requiring an analysis of how the current price controls have been determined and the reasonable inferences from the context in which that occurred. Some of the indicators that are most relevant would include whether:

- There have been clear statements about the intended allocation of risk, and
- Whether the revenues underpinning current prices could be said to include an allowance in respect of a risk that is absorbed (and, in that case, what allocation of risk the particular allowance indicates).

Notwithstanding our view that the key question is a factual inquiry as to what risk allocation has been factored into current prices, we also address the question from first principles – that is, asking whether, of the risk allocations that could have been implemented, is the current approach appropriate? Anticipating the conclusions that are reached below, it is envisaged that this will assist in Orion’s broader communications of the merits of its CPP application.

These two matters are addressed in the following section.

3.2. Assumptions of the current regulatory regime

3.2.1. “First principles” analysis of risk allocation

As discussed above, any option for dealing with the cost consequences of catastrophic events must result in consumers bearing the cost of those events, at least in an “expectation” sense.¹¹ The key question is whether the regulated business should be compensated in advance of the event through an allowance that is akin to a self insurance premium, and then bears the risk of the event, or whether the compensation to the regulated business is based on the actual costs of the event. A second and related question is when consumers should pay these costs – should there be an effort to smooth them over time, including through payments being made in advance of the event, or should this await the occurrence of the event. The smoothing naturally occurs if the regulated business is compensated through an annualised allowance akin to an insurance premium, but could be incorporated into a model whereby the compensation to regulated businesses is based ultimately upon on the cost of the event.

Implications of workably competitive markets

The starting point for analysis under the purpose statement is to address the question of what would be expected to occur in workably competitive markets. The response of this depends in part on the form of workable competition that is taken as the hypothetical case. Two alternative formulations – and the implications – are as follows.

- In a market where there are repeated transactions and continual entry and exit from the market, firms will be limited in their ability to recover costs after the event, being restricted to only recovering the costs that new entrants would incur. Thus, to the extent that the event caused forward-looking costs to be higher, then these costs would

¹¹ That is, to pay an annual amount equal to the actuarially fair cost of the event. This will recover the cost of the event over the average duration between events if all assumptions about the cost of the event and frequency are correct.

be recovered after the event; however, other costs (such as the premature replacement of assets) could not be passed through into prices, which would be expected to account for the vast majority of the costs. However, it is also clear that firms would only choose to enter the market where it was able to set prices to compensate it for the risks and costs it expected to incur. The consequence is that, for the majority of the risks associated with a catastrophic event, the cost associated with catastrophic events would be factored into prices in advance.

- However, the Commission and its advisers during the Input Methodologies review referred to different formulations of workable competition, with an apparently preferred formulation being one where users of a service were assumed to enter into long term contracts for the service, with the competition taking place at the time of awarding the contract. In such a market, it would be feasible for a different risk allocation to be agreed between the parties, with the risk associated with catastrophic events either being shared or borne by the user of the service.

Accordingly, I would conclude that an analysis of the more standard formulations of workably competitive markets would direct attention towards an ex ante compensation for the cost consequences of these events. This implies that consumers bear the cost of catastrophic events through ex-ante compensation and “true up” would occur in light of the actual frequency and consequences of such events. As well as being a product of competition (and thereby a constraint), the reliance upon ex ante recovery is more feasible in competitive markets given the greater ability for firms in such markets to insure against such events. As noted in the Marsh report, this is not the case for electricity network businesses.

In contrast, however, I note that the formulations of workably competitive markets that have been considered by the Commission as more relevant for infrastructure services are much less definitive and encourage an inquiry into the merits of a particular risk allocation.

Allocating the risk of catastrophic events – the regulatory context

The specific nature of catastrophic events and their potential effect on electricity infrastructure pose a number of challenges for the design of regulation where firms are regulated. In particular, such events:

- May have a substantial effect on cost, but
- Cause a range of costs, some of which are subtle and difficult to clearly separate out (for example, in the case of Orion, the effect of the earthquakes on the cost of future augmentation expenditure in view of the changed location of demand),
- Be very difficult to predict the cost and the frequency of such events in advance, and
- Lack access to complete insurance from external providers at a reasonable price, in particular with respect to lines and cables.

This creates a number of important implications where firms are regulated and prices are determined with reference to cost.

First, it would be impracticable to apply an ex ante regime to all of the consequences of a catastrophic event. In particular, this would require the regulator to identify and separate out

costs that are considered incremental to the event. Some components to the incremental cost may be obvious (such as the premature replacement of damaged assets) whereas others may be more difficult to identify (such as the additional cost of maintaining a secure system in view of the changed location of demand). Moreover, if the incremental costs were to be separated out, this would require such a separation to be performed (in principle at least) at all future reviews of prices. Moreover, even for those cases where it appears at first sight to be obvious as to what additional cost has been caused by the event, the dividing line may turn out to be much less clear in practice.

Secondly, the fact that the scope of external insurance (at least for a reasonable price) is limited has two further implications:

- A substantial part of the ex ante allowance would be in the nature of a self insurance premium that could not be determined with reference to observed market prices. This, in turn, would require the regulator to form a view upon the frequency of catastrophic events and their expected consequences. This is an extremely complex and possibly impossible task – after all, a key reason as to why external insurance is not available for the full range of consequences of a catastrophic event is because of the difficulty of predicting the frequency and consequences of such events. This task then is likely to become extremely contentious because if the assumed frequency and/or consequences of the event are incorrect then windfall gains (loss to consumers) or losses (gain to consumers) will accrue.
- The regulated business would bear a substantial share of the risk associated with such events. Depending upon the size of the event, this could expose the business to a risk that could affect its viability and ability to raise finance, and arising at the very time when substantial work would be required to restore service to consumers.

It follows that, viewed through the lens of regulation and absent access to comprehensive external insurance at a reasonable price, an ex ante regime for catastrophic events has a number of undesirable characteristics. The regime is likely to invoke substantial controversy, both when deriving the ex ante allowances and, after the event has occurred, distinguishing the costs that are caused by the event (or intended to be borne by the regulated business) from those that are not. Moreover, depending upon how much risk is intended to be borne by the regulated business, the occurrence of an event may adversely affect the ability for the firm to raise finance. This would either put at risk or slow down the recovery from the event, or cause the regulator to allow some or all of the risks to be passed on to consumers (notwithstanding previous commitments).

In view of these matters, I conclude that an ex ante approach for compensating for the cost of catastrophic events is inappropriate and that an ex post approach is most justified from a first principles analysis. It is noted here that the most in depth discussion of this matter in Australia – in a decision of over a decade ago – made similar observations to those above:¹²

Subsequent to the receipt of the submissions, the Office convened a workshop to discuss a number of issues related to the cost of capital, one of which was how the

¹² Office of the Regulator-General, 2000, Electricity Distribution Price Review – Final Decision, September, p.320.

Office should treat high cost, low probability events. The Office noted that there are (conceptually) two means of treating such events, which are:

- *to provide a self-insurance premium, and impose the risk on the distributors; or*
- *not to make an explicit allowance, but to deal with such events when they arise (implicitly passing the risk onto customers).*

The Office noted that neither approach is perfect. The former approach assumes an accurate quantification of the expected cost from such events is necessary, and that the businesses are in a position to bear such a risk at the time. However, it involves a moral hazard risk for customers in that they would pay the self-insurance premium in advance, and the distributor could be unable to carry the risk in practice when the event occurs. It also requires there to be a distinction drawn between these special events, and routine events. The latter approach, however, would require the commitment (for the regulatory period) to pass the risk onto customers to be maintained. [footnotes omitted]

I observe that the Commission and the Commission's advisers reached the same conclusions about the merits of an ex ante regime (or, more specifically, on the merits of a transfer of risk to the regulated businesses):¹³

Professor Myers argues that ideally compensation for regulated firms should also occur ex ante. But in practice the size of the premium will be hard to justify to regulators, so some combination of ex post and ex ante compensation will be unavoidable. The form of compensation should depend on the nature of the risk.

Professor Myers recommends that type I risks could be handled by allowing regulated firms to charge an 'insurance premium' that is invested in a reserve fund, which would pay out in the event of a type I occurrence (effectively, a form of self-insurance that mimics what might otherwise occur, absent regulation). If the fund turns out to be inadequate, the Commission could allow some ex post compensation. If the fund accumulates too much money, part of the fund could be returned to consumers.

I interpret these remarks as expressing a desire for commencing recovery of the cost of such events in advance of them occurring (a matter that is addressed next) but not leaving the regulated business bearing the risk (which would include retaining the benefit) flowing from inaccuracies of the cost or frequency of such events.

A factor that needs to be managed where recovery is permitted of the actual costs of responding to a catastrophic event is the potential for a "guarantee" of cost recovery to diminish the business's incentives for prudent behaviour. It would not be unusual in this circumstance for a regulator to test the prudence of expenditure prior to permitting its recovery – the intention of the review being to provide a substitute incentive for performance rather than necessarily expecting to find costs to disallow. It is noted that two sets of decisions could be tested, namely:

¹³ Franks, J., Lally, M., Myers, S., Recommendations to the New Zealand Commerce Commission on an appropriate Cost of Capital Methodology, 18 December 2008, p. 38.



- whether actions prior to the event efficiently minimised the consequences to consumers of the event, most relevantly whether the business had a prudent level of insurance and whether the network had an efficient level of resilience to potential catastrophic events, and
- whether the response to the event was prudent, noting, however, that a proper application of a test of prudence would take account of the constraints on decision making that were caused by the event.

We observe, however, that the threat of an ex-post prudence test of expenditure brings with it the risk of the regulator incorrectly disallowing appropriate expenditure. The chances of the inappropriate disallowance of prudent expenditure can be managed by putting clear bounds on the application of the ex-post prudence test, and the key elements of a well designed ex-post prudence test include:

- the regulator not applying hindsight to its decisions, including that regard is had only to information that was available to the business, and would have appeared relevant, at the time it made its decision
- the review should be based on whether expenditures were the result of prudent decision making and not whether they reflect “best practice” or some measure of “frontier” expenditure, and
- the regulator should accept the onus of proving that expenditure was imprudent, rather than for the business to prove prudence.

Should there be advance recovery of the cost caused by catastrophic events?

Insurance programs are widespread amongst utility firms and provide a means of shifting the risk associated with the frequency and occurrence of catastrophic events away from both the consumers and regulated business to a wider pool of parties. It will be in the interests of consumers for this insurance to be taken out by regulated businesses provided that it is available at a cost that does not exceed the value that consumers would place upon removing this risk.

However, it was observed above that there are limitations to the insurance coverage that is available from external sources. It was also observed above that regulation should provide an expectation that firms be able to recover operating costs and at least make a commercial return on investment. In combination, the implication is that consumers will be required to bear those costs that cannot be insured externally.

One of the issues addressed by the Commission’s expert advisers on the cost of capital was whether the recovery of the cost caused by natural disaster (assumed here to be the uninsured portion) should commence in advance of an event occurring. In practice, this would imply adding an increment to prices and quarantining the funds raised, to be used to defray the cost of responding to a future catastrophic event. The intended purpose of such a measure would be to spread the costs of responding to a catastrophic event to the period both prior to and after the event in question.

Notwithstanding the Commission’s expert’s support for such a measure, in my view the merits of the measure would depend upon the specific facts surrounding the company in

question. I note further that there are two polar options that would deliver broadly similar results for consumers in the long term, namely to:

- seek to recover the costs associated with catastrophic events at a constant rate over time, irrespective of the timing of such an event, or
- recover the costs after the event occurred.

These options would both involve consumers at all times paying for the consequences of one catastrophic event, the only difference being whether consumers are paying for the cost of responding to what is likely to be a mix of the last and next event, or are paying to remedy the consequences of the last event.¹⁴

I observe, however, that where a catastrophic event has just occurred and consumers had not pre-paid for the cost of the event, then they would be paying for the costs of one event. In this case, if consumers were asked also to make provision for the next event then they would be contributing more than would be reasonable. Clearly this is the case for Orion's consumers, which I return to below.

3.2.2. Application to Orion

Assumptions in the current regulatory regime with respect to the allocation of risk

In my view, the context within which the current price controls were determined conveyed a reasonably clear assumption that regulated businesses were not assumed to bear the risk of catastrophic events,¹⁵ but would pass the costs through to consumers if such an event occurred. I also think it is reasonably clear (or as clear as is possible within the context of the New Zealand regime) that no allowance was provided to Orion (apart from the recovery of the cost of external insurance) for bearing any such risk. Moreover, I note that the Commission's subsequent decisions on this issue – including the Input Methodologies Determination and its informal discussions with Orion – have put these assumptions into effect and that there is no disagreement with the Commission on how these costs should be treated.

Turning first to the context within which the current price controls were determined, the New Zealand regulatory regime for electricity distribution businesses is somewhat unique in that there is an intention that default price controls be established based upon a fairly high-level analysis and without an analysis of firm-specific issues, with the businesses then able to propose a customised approach if the default price controls materially understate cost. In addition, where customised price controls are put in place, the Commission has the discretion to retrospectively adjust for any shortfall (or surplus) that occurred prior to the

¹⁴ The other obvious difference is that where costs are recovered after an event occurs, there is no need to predict the cost or frequency of an event – the event would have occurred and the costs are measurable.

¹⁵ The current price controls for Orion were determined on 30 November 2009, and therefore I have focussed on the context as at that date, although the Commission's subsequent decisions also provide evidence of what was expected earlier in the process of developing the Input Methodologies.

customised price controls coming into effect.¹⁶ In such a regime, it is difficult (albeit not impossible) for compensation for catastrophic events to be addressed through an ex ante allowance, given that this would require analysis of the specific environment faced by each business. Thus, I consider it reasonable to assume that the structure of the regime at least creates a presumption that the costs associated with such events would be treated after they occur.

In addition, the matter of how catastrophic events should be treated in the regime – including a recognition that compensation is warranted and the broad options available – had already been canvassed at the time that the current price controls were determined, with the advice to the Commission (and its own view) being a preference for not transferring this risk to the regulated businesses. The Commission’s statement – which adopted the advice of its advisers – was as follows:¹⁷

With these issues in mind, Franks et al (2008) have proposed a hybrid scheme that mixes ex ante and ex post allowances. In particular, they recommend that the Commission handle Type I risks by allowing regulated firms to charge an ‘insurance premium’ that is invested in a reserve fund, which would pay out in the event of a Type I occurrence (effectively, a form of self-insurance that simulates what might otherwise occur, absent regulation). Ex post adjustments could be made if the fund proves inadequate or too generous.

The key point from this paragraph is the reference to ex post adjustments if the settings for the fund were incorrect – this adjustment means that the fund would not transfer the risk of such events to the regulated business, but rather seek to smooth the recovery of this cost over time.

Moreover, in my view, the Commission’s subsequent decisions in relation to the Input Methodologies are clear as to how the cost-consequences of catastrophic events were to be treated, namely that the costs would be recovered if and when such an event occurs. While these decisions were made after the current price controls were determined, they provide evidence of the expectations of parties during the discussion.¹⁸ The Commission endorsed the reasoning above that it is difficult to make an ex ante allowance for asymmetric risks (of which the exposure to catastrophic events is one) in the context of a DPP regime in view of the intention that such controls be determined without a detailed analysis of firm-specific issues.¹⁹

The IM applies a ‘benchmark’ or service-specific cost of capital for all suppliers of a regulated service. If the Commission were to apply an ad-hoc adjustment to the

¹⁶ Commerce Act, section 53V(2), although the Commission has noted its intention to apply this discretion more narrowly – albeit carving out catastrophic events as a case where claw-back is permitted back to the date of the event (Input Methodologies, clause 5.3.4(4)(b)).

¹⁷ Commerce Commission, 2009, Revised Draft Guidelines for the Cost of Capital, June, p.54. The Commission’s discussion on this matter was directed towards the feasibility of creating such a fund.

¹⁸ I note that this is not an issue where parties to the Commission’s consultations expressed surprise as to the Commission’s final position.

¹⁹ Commerce Commission, 2010, Input Methodologies Reasons Paper, December, p.571.

service-wide cost of capital it would imply that all suppliers of a particular service are exposed to the same level of asymmetric risk. However, suppliers of a regulated service are exposed to different levels of asymmetric risks and at possibly different time periods. If the IMs were to make an ad-hoc adjustment for asymmetric risks in the service-wide cost of capital, it may over-compensate some suppliers and possibly under-compensate other suppliers.

The decision not to specify in the Input Methodologies that regulated prices should compensate for the expected cost of catastrophic events is consistent with an intention to allow the costs caused by such events to be recovered after the fact. Moreover, this intention is reflected clearly in the specific and general provisions in the Input Methodologies, that is:

- Where an electricity distribution business seeks a customised price path after a catastrophic event, there is a requirement for claw-back to apply covering the period after that event,²⁰ implying an intention that these events be address through application of a customised price path. There are also detailed provisions directing the Commission to identify (and thereby allow recovery of) all of the incremental costs caused by the event.²¹
- As a general matter, the regulatory asset base is calculated by including all past capital expenditure,²² which would naturally allow recovery of the financing cost associated with all incremental capital expenditure (and continued recovery of the cost of assets that may have been replaced prior to the expiry of their lives).

I observe that the Commission in responding to Orion's proposal would remove any remaining doubt as to how costs caused by catastrophic events would be treated, thereby further reducing risk in the sector and thus enhancing further the incentive for investment.

Turning to whether as a matter of fact Orion's price controls include an allowance in respect of catastrophic events, I acknowledge that it is difficult to be definitive about which particular costs are reflected in Orion's price controls because Orion has not had price controls set transparently with reference to cost. However, I observe that costs have featured in the previous regime in a number of ways, including:

- in the calculation of profitability that was used in the derivation of the "thresholds" for the 2004 to 2009 period
- the reported outturn return on assets under the disclosure regime that also operated over the 2004 to 2009 period, and
- were expected by all parties to be a key input into the setting of the starting prices under the default price path, which has transpired as a correct expectation.

None of these uses of the concept of "cost" has included an allowance in respect of catastrophic events, apart from the recognition of insurance premiums paid to external insurers.

²⁰ EDB Input Methodologies, clause 5.3.4.

²¹ EDB Input Methodologies, clause 5.6.

²² EDB Input Methodologies, clause 5.3.6.

I reiterate the point made in section 3.2.1, however, that the outcomes for consumers need not be materially different depending upon whether Orion was assumed to bear the risk associated with catastrophic events, or whether this was intended to be recovered directly from consumers. In particular, if Orion was intended to assume this risk (or, more accurately, bear the expected cost), then it would need to be compensated for this, and that compensation, with that compensation continuing into the future. The difference in outcomes for consumers (at least over the long term) between the two approaches would arise due to the assumptions about the frequency and consequences of such events being incorrect, in which case consumers could face a windfall gain or loss.

Price cap regimes and demand risk

In the previous discussion I have emphasised that the loss of anticipated revenue arising from a reduction in demand is no different conceptually to the requirement to incur additional expenditures, meaning that a failure to compensate properly for either will lead to costs not being recovered.²³

It could be observed, however, that price caps are intended to shift some demand risk to suppliers. In turn, the question could be asked whether compensation is required for the demand risk associated with catastrophic events and, if so, why this form of demand risk is different to “normal” demand risk, for which specific compensation is not provided.

The answer to this question is that whether or not specific compensation is required in respect of a particular source of demand risk depends upon whether that risk is expected to have a symmetric or asymmetric effect on returns.

- Most of the demand risk to which suppliers are subject can be assumed to have an approximately symmetric effect on returns. This means that the supplier has a roughly even chance of demand being higher than expected (and delivering commensurately higher returns) than it is being lower than expected (and delivering commensurately lower returns). If the relevant source of demand risk is expected to have a symmetric effect on returns, the supplier would expect to earn the WACC on average, and no further compensation is required. The assumption of a symmetric effect on returns is reasonable for many of the sources of demand risk, for example, economic growth and population growth.
- In contrast, an adverse shock to demand arising from a catastrophic event is asymmetric – there is no offsetting positive event that would cancel out the downside. Thus, specific compensation is required to ensure that the supplier expects to earn the WACC on average.

As with expenditure items, the specific compensation referred to above could be provided ex ante or ex post, although I argue that the latter is more appropriate from a first principles analysis. I note further that, in parallel with expenditure items, there is no evidence that the

²³ As implied in the discussion above, an additional fact that is relevant is that most of Orion’s costs are fixed (amongst other things, comprising investments in irreversible investments). This means that the reduction in demand would not have led to a material (let alone a proportionate) reduction in cost.

Commission has provided *ex ante* compensation for the demand risk associated with catastrophic events when undertaking its various duties.

- In parallel with the discussion above, recognition of this element of demand risk would have required the Commission to revise down measured profit to make an allowance for the actuarially fair consequences for revenue of a catastrophic event. This has never occurred.
- Similarly, the Commission's proposed method for setting the default price paths would not result in compensation being provided for the demand risk associated with catastrophic events. Providing this compensation would have required the Commission either to (i) include an allowance for the actuarially fair consequences of such an event for revenue as an expense item, or (ii) adjust its demand forecasts to remove the actuarially fair loss of demand associated with the prospect of such an event, neither of which has been proposed by the Commission.

As discussed above, the observation that the Commission has not provided *ex ante* recognition or compensation for these risks is not intended as a criticism. This approach is consistent with the expectation that these events would be addressed *ex post*, which I have concluded to be the most appropriate means of addressing these risks.

Prudence of Orion's expenditures

As noted above, it is not uncommon for a regulator to foreshadow an *ex post* review of the efficiency of capital expenditure in circumstances where that expenditure was undertaken in an environment where the incentives for efficiency were weak.²⁴ This could be argued to be the case under a regime where a full pass through of costs associated with a catastrophic incurred were assumed, although I note that the uncertainty in the current regulatory regime and the visibility to the community of the response to such an event are mitigating factors.

I have not undertaken a comprehensive review of Orion's actions to determine whether it took prudent actions prior to the earthquake to ameliorate the consequences of such an event. However, from the information I have reviewed, Orion would appear to be well placed to demonstrate that it was prudent in its preparations for, and response to, this event. In particular, I note the following:

- I have been informed that an objective of Orion's network design and investment strategy was focussed on the resiliency and diversity of its electricity distribution network in order to minimise the impact of such an event on network infrastructure and supply continuity. For example, I am aware that Orion favours using multiple network routs and interconnections into each area in Christchurch. In addition, Orion recently completed a 15 year and \$6 million major program of strengthening key substations against such risks. I am further informed that without such strategies or works, the repair bill would have been materially higher and the length of the power outages in the area would have extended for much longer than was realised.

²⁴ I note that such a test is not factored into the Input Methodologies, but is addressed here for completeness.

- I have also been provided a report from Marsh on Orion's approach to insurance prior to the earthquakes occurring. The key finding from the Marsh report is that, given the nature of Orion's business and the market for insurance, its approach was consistent with good industry practice.

Issues flowing from Orion's ownership

As discussed earlier, while Orion is community owned, we have assumed that it operates as a commercial entity so that, like privately owned entities, its incentive to invest is conditional on recovering efficient cost and making a commercial return.

I observe that this assumption is consistent with Orion's obligations under the Energy Companies Act. Section 36(1) of the Energy Companies Act states that the principal objective of an energy company shall be to operate a successful business. I note that critical requirement for the success of any business – and for a capital intensive business in particular – is to make a commercial return after recovering efficient costs. The assumption that Orion operate as a commercial entity is also consistent with the assumptions implicit in the regulatory regime applicable to Orion and other like community owned entities.

In addition, I note that the efficiency of electricity use – and the efficiency of the allocation of resources in New Zealand more generally – is also enhanced by treating Orion like a private entity when setting regulated prices. This is because such an approach ensures that the prices reflect cost, including a risk-adjusted return on capital. Such prices discourage consumers from using electricity where they value it less than its cost, which in turn ensures that supply capacity is built for efficient use and resources otherwise flow to producing different goods and services.

Moreover, as Orion's owners are the councils whose areas were most affected by the earthquakes, the local population is expected to ultimately pay for the costs caused for Orion, with the choice being whether this is direct (through electricity charges) or indirect (through higher council rates, being a consequence of reduced earnings from their investment in Orion). However, the former could be seen to be a fairer means of spreading the cost burden as it would mean that an individual's share would reflect its proportionate use of the electricity infrastructure.

I am also aware that concerns have been expressed about whether Orion (through its community ownership) may not have sufficiently "diversified" its exposure to the risk of such a catastrophic event, and that as a consequence some of the cost it incurred is inefficient and should be disallowed.

This was a matter that was discussed above, and the conclusions are summarised below. In short, this argument mistakes the role and effect of diversification – the same costs would have been suffered irrespective of who was the owner of the assets.

- Diversification is undertaken by investors to reduce the risk premium that they require for holding an asset that generates volatile returns. The regulatory WACC for Orion (as determined by the Commerce Commission) assumes that the owner of Orion holds that asset as part of a diversified portfolio – that is, the risk premium is the minimum that any investor would require.



- The key effect of a catastrophic event as argued in this report is not to increase the volatility of Orion's returns (and thereby possibly create an argument that investors require a greater risk premium), but rather to increase the costs that it faces (i.e., the need to repair assets, loss of revenue, etc.). This is a cost that would have been borne irrespective of who owned the assets – it is a function of the fact that electricity infrastructure needs to be constructed in the location of consumers, and this is where the earthquake occurred.

4. Cost recovery over time

The purpose of this section is to consider the second key question Orion has asked me to address, namely, how should cost recovery be spread over time.

Consistent with the previous section, I first consider the relevant economic principles that are applicable to the question of the timing of cost recovery, followed by a consideration of the current regulatory framework. I then make some concluding comments with respect to the circumstances for Orion.

4.1. Relevant economic principles for cost recovery over time

Prices are the means of signalling to consumers the costs of providing services, and as such, when and how much they should consume at a particular point in time. Prices are also the source of providing revenue to regulated businesses so they can fund their activities. Prices therefore, are also the mechanism for providing a regulated business with the necessary revenue to compensate it for the costs incurred in responding to the earthquake. There is a tension, however, between ensuring that prices provide a sufficient cash flow to fund costs for the business following such an event while also avoiding creating distortions to the consumption decisions of consumers.

It is important to understand at the outset that while it was the earthquake that caused additional costs to be incurred, these costs were, nevertheless, incurred for the benefit of consumers. As an extreme example, had consumers decided they no longer wished to use electricity following the earthquakes it may not have been necessary for Orion to incur much of the expenditure it did in order to restore supply. The point of making this clear is that it is appropriate that the costs of the response are passed onto consumers.

A real rise in prices in order to recover the costs of a catastrophe might change the consumption behaviour of consumers. Most significantly, some consumers may choose to disconnect from the network altogether. This is more likely from industrial and commercial consumers who have more alternative options, including self supply, relocation of their premises or complete shut-down. Residential consumers, however, might seek to reduce consumption in order to reduce the overall impact of the price rise on their budgets (irrespective of whether costs are recovered through the fixed or variable component of prices).

The risks of disconnection or reduced sales occurring are dependent on the price sensitivity for each consumer type. Given a catastrophic event might be expected to also have cost implications for consumers in a region, there is a chance that the price sensitivity of consumers might increase following such an event.



There is good reason why it might be desirable to seek to avoid consumers either disconnecting or reducing overall sales. The reduction in either consumers or sales would mean that overall revenue to the electricity network business is reduced. This in turn would risk the ability for the network business to earn sufficient revenue to cover its costs. In order to earn sufficient revenue to cover costs in this circumstance prices would need to rise further again to those remaining consumers. This would risk a further round of consumer disconnections or reduced sales.

The circular problem of increasing prices leading to reduced revenue and further rises in prices can be mitigated by extending the period over which costs are recovered. That is, rather than recovering the costs associated with the claw-back of costs over one regulatory period, these costs could be recovered over multiple periods. The intent would be to keep prices level in real terms over the long term so to avoid consumers disconnecting or reducing consumption. Indeed, it may also be possible to delay, or back-end, any recovery of costs until future periods. This would be in recognition of any short-term heightened price sensitivity of consumers affected by the catastrophic event.

For completeness, I note that there are a number of different categories of incremental cost caused by the earthquakes. These include the short term loss of revenue and repair related costs, as well as longer term costs caused by the changed location of demand and reduce level of consumption. Importantly, however, the decisions of consumers are affected by prices, which in turn reflect the aggregate impact of the recovery of all categories of these costs, in combination with the aggregate impact of the recovery of Orion's underlying costs (that is, those costs that would have existed absent the earthquake). Thus, the reasonableness of the proposed method for recovering any single category of costs needs to be assessed against its impact on the overall time profile of prices in combination with the proposed method for the recovery of all other costs.

There is a natural limit, however, to how far cost recovery can be delayed or extended. This is because a delay or extension of cost recovery has impacts on the cash flow of the business. If the pattern of cash flow is not consistent with the efficient financing of assets this can impact on the financial viability of the business as well as the overall costs of service provision.

It is in society's interest that asset owners are able to access the deepest and lowest cost forms of debt finance. Securing debt finance of this type requires certain minimum measures of debt servicing capacity to be met in all periods. Changes to the pattern of cash flow can enhance or deteriorate a business's credit metrics if the strength of the cash flow differs across periods. Ensuring cost recovery is not unduly delayed or extended can minimise the risks of impacts on the debt servicing ability of the business and hence the overall costs of service provision.

4.2. Commerce Commission approach

While the Electricity Authority has responsibility for the price methodology for electricity distribution businesses, it is the Commerce Commission that sets the price control. It is the price control that determines the level and timing of cost recovery over time. Therefore, I focus here on the Commerce Commission's approach rather than the pricing methodology of the Electricity Authority.

Statements by the Commerce Commission indicate that it acknowledges the interaction between the need for prices to ensure sufficient revenue while also recognising that price levels have an impact on consumption behaviour:²⁵

Prices and quality (s 52A(1)(b) and (c)). Price and quality are inextricably linked because they are the two key aspects of goods and services that are often of most interest to consumers. In workably competitive markets, consumer demand is responsive to changes in price and quality. Prices provide appropriate signals for allocating resources efficiently within the economy, and provide a level of profits just sufficient to reward investment, innovation and efficiency. In the case of regulated suppliers, ensuring prices result in revenues that provide a normal rate of return is only one of the necessary conditions for allocative efficiency. Allocative efficiency is not only dependent on overall revenue, but is also dependent on individual price levels and structure, because consumers respond to the prices that they face, rather than to the revenues that firms make. Similarly, service quality is more important to consumers at an individual service level than on a whole-of business basis.

In the context of setting the P_0 and X-factor under a CPP, the Commerce Commission has also specifically acknowledged there is a trade-off between avoiding price shocks for consumers and maintaining the cash flow needs of a regulated business:²⁶

However, the appropriate balance between P_0/X will be situation-specific and depend, among other things, upon the cash flow needs of the CPP applicant and the extent of possible price-shocks to its consumers.

There remains a question, however, about whether the current formation of the Input Methodologies facilitates the delayed or extended recovery of some of the incremental costs caused by a catastrophic event and the principles are applied to maintain an appropriate cash flow for the business.

In relation to new capital expenditure, I note that the Input Methodologies provide substantial flexibility over depreciation methods applied under a CPP, and provide certainty that the depreciation method adopted under a CPP will be applied to update the regulatory asset base when the control is reset (either as a new CPP or a DPP). The implication of this is that the Input Methodologies provide substantial flexibility (together with certainty) over how the incremental costs associated with capital expenditure are spread over future regulatory periods.

However, in relation to the claw-back component of costs the situation is less clear. In particular, what is less certain is whether any costs that have not been recovered over the five year period of the CPP can be recovered in future periods (either under a new CPP or a DPP). On the question of whether the amount of the claw-back that is unrecovered at the end of the initial CPP period can be recovered in future periods under the Input Methodologies as currently drafted, I provide the following observations:

- If the next control is a new CPP, the question comes down to the meaning of clause 5.3.4 of the Input Methodologies, and in particular the meaning of “any value of

²⁵ Commerce Commission, 2010, Input Methodologies Reasons Paper, December, p.36.

²⁶ Commerce Commission, 2010, Input Methodologies Reasons Paper, December, para.9.1.17.

claw-back for the CPP regulatory period” as this clause defines the extent to which regulated charges are able to recover something more than the building block allowable revenue.

- In my view, this clause can be read to allow the recovery in one CPP period a claw-back amount that has emanated (and was first recovered) in a previous CPP period. In particular, the clause refers to the value of claw-back **for** the CPP regulatory period, rather than the value of claw-back **emanating from** a particular period. Thus, if there was a large claw-back amount determined now, and this was spread mechanistically over several future regulatory periods, my view is that this clause would require the Commission to permit the recovery of claw-back in those future periods in line with the original intention.
- I observe, however, that the Commission would need to be clear in the original CPP determination (i.e., 2014-2019) about the aggregate claw-back amount that had been determined and the value (or a formula for determining the value) that is intended to be recovered in future periods. Creating such a formula is a straightforward task.
- If a distributor moved to a DPP, which would appear likely at least at some point in the future, the Commerce Commission would appear to have the discretion to permit continued recovery given its wide discretion when determining starting prices. This, however, would not be a requirement on the Commerce Commission. Again, clarity in the original CPP determination about the formula for cost recovery into the future may largely overcome any uncertainty of future approaches.

Alternatively, if more certainty is to be sought about the recovery of the claw-back amount while remaining within the current regulatory framework, an option is to recover the costs associated with the claw-back over the five year period, but delay the recovery of any new capital costs by extending (or back-ending) depreciation schedules. This could be done so as to achieve the desired certainty of the claw-back amount while ensuring a desirable overall impact on consumers.

4.3. Application of economic principles and existing framework to Orion

I recommend that the Commerce Commission should apply the following principles for the recovery of costs associated with the earthquakes:

- the timing of cost recovery should be spread over time in a manner that provides efficient use of the network, and
- the timing of cost recovery should also be consistent with maintaining the financial stability of the network business.

Both of these principles should be applied having regard to the *aggregate* impact of the separate recoveries on the time profile of prices and cash flow.

While the current framework appears to provide some flexibility to spread the recovery of the claw-back amount beyond the term of the initial CPP, over multiple periods, the Commission



should provide sufficient clarity about what approach it will take and the mechanisms it will use to do so in order to minimise any risk as to how amounts that remain unrecovered after the initial CPP will be treated in future controls.

* * *

Yours sincerely,

A handwritten signature in black ink, appearing to read "Jeff Balchin".

Jeff Balchin
Principal
Advisory

Index of Terms of Reference Requirements

Table 1: Terms of Reference Index

Terms of Reference Requirement	Section addressed in report
Specific consideration of the claw-back (ie: ex post) and forecast (ex ante) nature of our CPP proposal is required.	3.2.1 and 3.2.2
The role of the Commerce Act, Part 4 Purpose Statement, including the tension between each of the subparts of the Purpose Statement and the asymmetric risks of under investment by EDBs	3.1.1
The role of the Part 4 IMs, including the approach to asset valuation and cost of capital and CPP specific processes and rules	3.2.2, 4.2
The Part 4 and IM provisions for claw-back (section 52D and 53V) - including recoverable cost mechanisms (including the option for price smoothing beyond the CPP period), and the requirements to consider financial hardship and price shock	3.2.2, 4.2
Whether claw-back should compensate for uninsurable and unanticipated lost revenue and extra costs caused by catastrophic events relative to DPP assumptions	3.2.1
The respective role of DPPs and CPPs in meeting the Part 4 Purpose	3.2.2 and 4.2
The Energy Companies Act, which requires Orion to operate as a successful business	3.2.2
Orion's approach to insurance (in light of the Marsh expert report)	3.2.2
Orion's ability to manage its financial flexibility and resiliency through a combination of revenue, borrowings and its shareholder distribution policy	2.2 and 4.1



The nature of Orion's unanticipated costs and losses – for example there is not a one to one relationship between Orion's extra costs and improvements in SAIDI/SAIFI performance and many of the unanticipated costs relate to security of supply rather than short term reliability performance.	2.3
Orion's obligation to consult with its consumers and other stakeholders (for example ratepayers) about its CPP proposal.	1
The relevance of other determinations to Orion's CPP, including the proposed EDB DPP reset and Transpower's price resets.	3.2.2
The relevance of the Commission's CPP determination for Orion, to the operation of Part 4 and the signals that will be sent to other regulated suppliers.	3.2.2

Appendix 2

James Mellsop and Will Taylor of NERA
Expert Report

MEMO

TO: David Freeman-Greene, Orion
DATE: February 6, 2013
FROM: James Mellsop and Will Taylor
SUBJECT: Peer review of PwC report on cost recovery following a catastrophic event

1. Introduction

Orion has been regulated under the Commerce Act Part 4A thresholds regime and more recently a Commerce Act Part 4 default price path. As a result of the 4 September 2010 and 22 February 2011 Christchurch earthquakes Orion:

- Has incurred and will incur extra costs; and
- Has received lower and will receive lower revenues.

These extra costs and lower revenues (which we will refer to jointly as “losses”) are not insured, and indeed (we understand) are not (economically) insurable. Accordingly there is an “insurance gap” which must somehow be funded.

Orion is now applying for a customized price path (“**CPP**”), and a relevant issue is whether Orion’s consumers (as opposed to Orion’s shareholders) should bear the losses, both historic and forecast. Orion engaged Jeff Balchin of PwC to consider these and related issues – Mr Balchin’s report is dated 17 December 2012. Orion has now engaged us to undertake a peer review of Mr Balchin’s report.

At page 2 of his report, Mr Balchin decomposes the Orion terms of reference into two related questions:

- *“Where, considered over the long term, should the incidence of cost recovery lay between Orion and its consumers?”*
- *“Where costs are recovered from consumers, how should cost-recovery be spread over time?”*

We address Mr Balchin’s analysis of each of these questions in turn. We agree with the conclusions reached by Mr Balchin, although in certain cases we would reach them through a slightly different chain of logic. In summary, we think the uninsurable losses arising from the Christchurch earthquakes, and any future catastrophic events, should be recovered from customers on an *ex post* basis.

2. Who should pay?

2.1. Summary of Balchin analysis

Mr Balchin's answer to the first question is that all "efficient and prudent" costs should be recovered from consumers. The chain of logic leading to this conclusion is as follows:

- Price regulation balances the competing tensions of ensuring continued and reliable service provision and the protection from market power abuse by setting cost reflective prices;
- The costs associated with catastrophic events are no different from other costs, they are just less certain;
- Demand reductions associated with catastrophic events are conceptually the same as a cost increase;
- If costs are not expected to be recovered in the long term, the sustainability of the industry will be jeopardized;
- Therefore firms should be able to recover the costs associated with catastrophic events from their customers.

Mr Balchin then analyses the secondary question of whether recovery should occur on an *ex ante* or *ex post* basis, or some hybrid of the two. Under a (pure) *ex ante* approach, the firm (shareholders) would bear the risk of inaccurate forecasting of the magnitude and frequency of catastrophic events.¹ Mr Balchin argues that in the case of electricity distribution businesses ("EDBs"), an *ex post* method is preferred for the following key reasons:

- A pure *ex ante* approach risks under- or over- compensating the regulated firm;
- Forecasting the frequency and costs of catastrophic events is very difficult, making an *ex ante* approach impractical;
- An *ex post* approach is implicit in the input methodologies and the regime in place when the current price controls were determined;²
- There is no evidence that EDBs have included a self-insurance premium in their prices so double counting is not a concern; and
- While a typical analysis of competitive markets would suggest an *ex ante* approach, the long term contract formulation of workable competition allows for other risk allocations.

Mr Balchin notes that an *ex post* approach may create a perverse incentive to incur inefficient costs and therefore a prudence test may be desirable.

¹ As noted by Mr Balchin on page 13, if the frequency and magnitude of catastrophic events are forecast accurately then the two approaches deliver the same outcome.

² E.g. page 19-20

2.2. NERA comment

2.2.1. *Who should pay: consumers or the firm?*

Mr Balchin rationalizes his key conclusion by referring to regulatory principle. We think the point can be made even more generically.

A firm will only enter a market if the firm believes it will recover its expected costs, including those arising from asymmetric risks (e.g., earthquakes). Some of those risks may be insurable, turning them into a (relatively) certain cost. Others may not be insurable, and so the expected cost would be a function of the probability of the event occurring.

Expected costs are recovered through the prices paid by consumers. It is a necessary condition of economic activity that consumers pay (the efficient) costs of production, which include those arising from asymmetric risks. So, at least as a matter of principle, we agree with one of Mr Balchin's key conclusions, being that "the efficient and prudent costs caused by catastrophic events should be recovered from consumers" (page 2).

Recovery of expected costs will be a function of expected revenues, which will in turn be a function of asymmetric risks (e.g., an earthquake that reduces demand). A firm will only enter a market if it expects revenues from its customers, taking into account asymmetric risks, to be sufficient to recover expected costs. In other words, expected prices would need to be high enough to account for the asymmetric risk of demand falling following a catastrophic event.

Therefore we also agree with Mr Balchin that demand reductions due to catastrophic events can be considered in the same way as cost increases.

To apply these principles to Orion's CPP further questions must be asked to determine whether the costs are "efficient and prudent", e.g.:

- Does the insurance gap exist because losses are uninsurable as opposed to Orion being negligent in its insurance practices?
- Did Orion take sufficient care prior to the earthquakes occurring?
- Are the costs being incurred now the most efficient way of repairing the network?

Mr Balchin defers to Marsh (an insurance brokerage firm) on the question of Orion's insurance practices and Orion itself on the efficiency of its decisions prior to and after the earthquakes. These are largely factual questions which the Commission is likely to test as part of the CPP process.

2.2.2. *Ex ante or ex post compensation?*

Assuming that the costs are efficient, the second question is whether losses should be funded on an *ex ante* or *ex post* basis, and who bears the risks of funding imbalances. Mr Balchin emphasises the

impracticality of an *ex ante* regime relative to an *ex post* regime, and the consistency of an *ex post* regime with the regulatory framework:³

My view is that the latter regime (compensation after the event occurred) has substantial practical advantages over the former. It is also consistent with the assumptions built into the current price controls, and is clearly the approach that is assumed in the new Part 4 of the Commerce Act and the Commerce Commission's Input Methodologies.

We agree with Mr Balchin's conclusion, although we reach that conclusion in a slightly different way.

We think the analysis can be usefully separated into two (related) questions:

1. How should the known and/or estimated losses associated with the earthquakes that have already occurred be recovered?
2. How should losses associated with future unknown events be recovered?

Regarding the first question, because the event has already occurred and the losses are known or can be estimated, the (policy) question of *ex ante* or *ex post* recovery is less relevant than the question of what (if any) "agreement" was in place for recovering these losses prior to the event occurring. Mr Balchin recognizes the importance of this analysis at page 14, although he also conducts a first principles analysis of *ex post* vs *ex ante* recovery before returning to the regulatory bargain in place when the earthquakes struck at page 19. In our view, and as canvassed by Mr Balchin, the "regulatory bargain" (defined by legislation and the Commission's approach to regulating EDBs) implies an *ex post* approach to the uninsurable risks:

- Under the Part 4A regime that preceded the present regime, there was no inclusion during profit assessments of any allowance for the cost of non-insurable catastrophic events (see page 21 of Mr Balchin's report);^{4, 5}
- The historic non-firm-specific approach to price control of EDBs in New Zealand (both under the repealed Part 4A and the new Part 4) means that there has never been a specific identification and quantification of *ex ante* compensation for uninsurable risks; and
- The claw-back mechanism is sections 52D and 53V of the Commerce Act, inserted into the Commerce Act in October 2008, i.e., approximately two years prior to the first earthquake. As

³ Page 3.

⁴ Costs were included in the "relative profitability" component of the price path thresholds, based on operating expenditures and asset values as disclosed by EDBs (see Commerce Commission, "Regulation of Electricity Lines Businesses Targeted Control Regime Threshold Decisions (Regulatory Period Beginning 2004)", 1 April 2004, paragraph 251), and there is no mention in the Commission's report (or in the related analysis of profitability undertaken by Meyrick Associates) of these costs including an allowance for non-insurable catastrophic events. Likewise costs were included in some measures of returns in the information disclosure requirements, but again there is no mention in the Commission's report that these costs include an allowance for non-insurable catastrophic events (see Commerce Commission, "Electricity Information Disclosure Requirements issued 31 March 2004", Consolidating all amendments to 31 October 2008).

⁵ This is particularly important as it ensures that *ex post* compensation now would not result in "double counting".

we understand this mechanism, it means the Commission can permit an EDB to recover historic losses under a CPP. This implies that the relevant risks are allocated to consumers, not the EDB.

In other words, Orion has not historically been charging an *ex ante* premium for uninsurable catastrophic events on the basis of a regulatory bargain that these costs would be recovered in full *ex post*.

As Mr Balchin notes, this might be different from what would be observed in workably competitive markets. To analyse what would occur in workably competitive markets, it is useful to categorise losses due to a catastrophic event into:

- Losses that are borne by all firms, including potential entrants; and
- Firm-specific losses.

Regarding the first category, if the catastrophe causes a cost increase for all firms in the market (e.g. insurance premiums or other input costs), market prices would simply adjust to reflect these costs.

Regarding the second category, if for example, firm A's factory burns down, consumers would simply switch to firm B,⁶ and firm A would find it difficult to raise prices to recover its losses (e.g., rebuild costs). Therefore, we would expect firms to recover this category of losses in an *ex ante* way via prices.^{7, 8}

For EDBs, risk allocation and compensation are controlled by the Commission and the regulatory framework, not by competitive market forces.

Regarding the second question of how future catastrophic events should be dealt with, a number of points must be considered:

- What method would be most consistent with workably competitive markets?
- What is the "regulatory bargain" going forward?
- Which allowable method is the most practical?
- What are the implications of the fact that Orion would be recovering losses resulting from a previous event on an *ex post* basis?

This is effectively what Mr Balchin's analysis (section 3.2.1) does. We agree that an *ex post* method would likely be the most practical. The fact the risks are "uninsurable" illustrates the difficulty for the Commission in trying to estimate an *ex ante* premium.

⁶ Or a new entrant.

⁷ This is the same point made by Mr Balchin at pages 4-5 of his report.

⁸ This is a general statement, and we do observe some markets where *ex post* responsibility for uninsurable events might be allocated to the customer, e.g., a price increase for unexpected soil conditions in fixed price construction contracts.

Regarding compatibility with workably competitive markets, for the “category one” costs discussed above, it would be consistent with a workably competitive market to adjust the price cap for changes in generic costs when an event occurs.

For “category two”, as discussed above, *ex post* recovery might not be consistent with a typical workably competitive market. However it would appear to be more practical and also likely consistent with the regulatory bargain.

On a related note, while the input methodologies appear to permit either an *ex ante* or an *ex post*⁹ approach under a CPP, paragraph K3.26 of the EDB Reasons Paper appears to rule out a hybrid approach for CPPs:¹⁰

*For the purpose of a CPP, the Commission will allow a supplier to recover an allowance for self-insurance as long as it is clear: what risks are being insured; that these risks are credibly self-insured (as opposed to being recoverable ex post through reconsideration of the price-quality path); and the self-insurance premium has been independently verified as appropriate by an actuary with the necessary expertise. A supplier must provide the information specified in clause D15 of the IM Determinations. **Should a self-insured risk eventuate during the CPP period, then the supplier will not receive ex post compensation for that event via a reconsideration of the price-quality path. [emphasis added]***

Mr Balchin briefly touches on the fact that if an *ex ante* approach is used going forward while an *ex post* approach is used for the historic earthquakes, consumers would be paying for multiple events at the same time and that this would be “unreasonable”.¹¹ Paying for multiple events at the same time could result in quite high prices over the next regulatory period(s) and distortions to consumption decisions, as we discuss in section 3.2 below. This is another argument for maintaining the *ex post* approach for future events.

Furthermore, an *ex post* approach would result in lower risk for the firm than an *ex ante* approach. In theory the extra risk to the firm under an *ex ante* approach could be compensated for through a premium paid by customers, but the fact that these risks are uninsurable highlights the difficulty of setting an appropriate premium. Therefore an *ex post* approach is more likely to facilitate investment by the firm than an *ex ante* approach.¹²

Of course, regulatory commitment will be crucial to achieving efficient investment, particularly given the long-lived nature of electricity distribution assets. For example, Orion will need confidence about the treatment of investments made during the CPP period in subsequent regulatory periods.

⁹ Through a claw back under section 52D and 53V as mentioned above.

¹⁰ Commerce Commission, *Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper*, December 2010.

¹¹ Page 19.

¹² As Mr Balchin points out, the downside of an *ex post* approach is a possible incentive to incur inefficient costs, which could be managed by a prudence test (see page 5 of Mr Balchin’s report).

3. Time profile of recovery

3.1. Summary of Balchin analysis

Mr Balchin's recommendations on this issue are:

- Cost recovery should be spread over time in a manner that provides efficient use of the network; and
- The timing of cost recovery should also be consistent with maintaining the financial stability of the network business.

Mr Balchin argues that “there is a tension, however, between ensuring prices provide sufficient cash flow to fund costs for the business following such an event while also avoiding creating distortions to the consumption decision of consumers.”¹³

The “distortion” is argued to arise from a short term increase in the price elasticity of demand due to the earthquake and the circularity of the EDB raising prices to recover its costs, which causes a reduction in volume which causes the EDB to raise its prices further.

The cash flow issue arises if there is a significant mismatch between the profile of the costs and the recovery of those costs.

3.2. NERA comment

On this issue, our main comment is that it would be helpful to distinguish between two types of losses related to the 4 September 2010 and 22 February 2011 earthquakes:

- The forward-looking losses; and
- Claw-back of historic losses.

In terms of distorting consumption, there is nothing wrong with consumers paying higher prices to reflect higher forward-looking costs that are spread over time in the normal manner – in fact, allowing these costs to be spread over time in the normal manner would incentivize efficient consumption decisions.¹⁴ The trickier issues arise when considering recovery of past (sunk) losses.

In our view it is the claw-back of losses for which there might be a concern about distorting consumption decisions. Clawing-back historic losses may raise the price above forward-looking costs, which could distort consumption. There might be customers whose willingness to pay exceeds forward-looking costs, but who do not consume as the claw-back inclusive price exceeds

¹³ Page 25.

¹⁴ Recognising that the economies of scale and scope in infrastructure mean that pricing is unlikely to be perfectly efficient.

their willingness to pay. This would certainly suggest spreading the recovery out over time, as Mr Balchin suggests.

It is possible that the consumption distortion issue is not a material problem. Mr Balchin argues that elasticity may have increased following the earthquake, and we agree that this could be the case as customers needing to rebuild might have the option of relocating. However, even if this is correct the elasticity of final demand with respect to lines charges is still likely to be relatively inelastic, given the “essentiality” of electricity and the fact that line charges are just one component of final electricity charges.¹⁵ Ultimately though this is an empirical question.

Finally, we think Mr Balchin is correct to raise a concern about cash flows and financing, particularly in light of the extraordinary losses that Orion faces as a result of the earthquakes. We think it is good practice for regulators to check the implication of proposed price controls for cash flows and financeability.

¹⁵ For example, for residential consumers distribution charges make up on average 29% of electricity charges in New Zealand - <http://www.powerswitch.org.nz/powerswitch/site-info/powerswitch-faqs/where-does-your-money-go>.

Appendix 3

LineTech Consulting Report on Proposed Reliability Standards

Independent Engineer's Report – Quality Standard Variation



Client: Orion New Zealand Ltd.

Final Report

OCTOBER 2012

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Document Independent Engineer’s Report – Quality Standard Variation

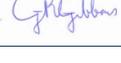
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Executive Summary

Orion New Zealand Ltd (Orion) is preparing a “customised price-quality path” (CPP) application to be submitted to the Commerce Commission (Commission). This follows the significant damage to its infrastructure caused by the series of earthquakes affecting the Christchurch area that started on 4 September 2010. This document is submitted under the catastrophic event provisions of the Commerce Act Electricity Distribution Input Methodology Determination, December 2010.

The Input Methodology Determination requires Orion to engage an independent engineer, to provide reports on certain aspects of that application. In particular a report is required on a quality standard variation from the default standards set by the Commission in accordance with clause 5.4.5(c) of the Input Methodology Determination.

This report has been prepared to meet the requirements for the variation in quality standards in accordance with clause 5.4.5(c) of the Input Methodology Determination

The approach adopted for this report has been to firstly review the set requirements for review by the Independent Engineer. This established that for the situation faced by Orion it is not considered realistic to apply the requirements for this Independent Engineer’s review strictly as written. Thus the approach adopted has been an examination of the Orion proposals to identify if they 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.

The proposals by Orion contained in the supplied draft Chapter 6 submission and associated documents were then reviewed in the light of the above.

It is the reviewer’s opinion that Orion has demonstrated appropriate trade-offs within the limitations set by the lack of clarity around aspects of the rebuild on the CBD; Long term population trends; the unknown state of parts of the existing network asset and the associated impact on failure rates and the level of risk of further earthquake damage.

The approaches adopted of reviewing theoretical optimum network architecture arrangements for both the sub-transmission and distribution networks is considered most appropriate as is the intention to check the application of these overall proposals when individual projects are analysed to review and ensure an optimal solution is found that balances economics, performance, safety and lifecycle considerations at the time of the decision being required.

The proposed set of targets set by year for SAIDI and SAIFI – including their boundary values - are considered to be an appropriate way of addressing targeted performance as projects are carried out to repair/replace the severe damage suffered. Whilst noting the Determination will set fixed targets it is understood Orion will internally review them each year to reflect the improved knowledge on the effects of the earthquakes on plant and equipment.

This review 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. In comparison to the application of the DPP methodology the quality standard variation as proposed by Orion is considered to be notably

better in reflecting the realistically achievable performance of the EDB (Orion) over the CPP regulatory period.

Contents

Executive Summary..... iii

1.0 Background/Introduction 6

2.0 Requirements..... 6

3.0 Review of Requirements..... 7

 3.1Context..... 7

 3.2 Consideration and Comparison of Catastrophic Events 8

 3.2.1 Failure Rates..... 8

 3.2.2 Loading Patterns 8

 3.3.3 Network Configuration 9

 3.3.4 Major Earthquake Risk 9

 3.3.5 Data Homogeneity 9

4.0 Review of Chapter 6..... 10

 4.1 Targets..... 10

 4.2 Synthesising of Data..... 10

 4.3 Moving Targets 11

5.0 Review of Supporting Data 12

 5.1 Network Architecture Review – Subtransmission 12

 5.2 Network Architecture Review – Urban 11kV 13

 5.3 Asset Management Plan. 14

6.0 Conclusions 14

Appendix A: List of Documents Provided for Review 16

1.0 Background/Introduction

Orion New Zealand Ltd (Orion) is preparing a “customised price-quality path” (CPP) application to be submitted to the Commerce Commission (Commission).

This application is under section 53Q of the Act, which allows for a supplier of electricity distribution services, such as Orion, to make a proposal to the Commission for a CPP which effectively permits the supplier to follow a different price-quality path from the default price-quality path that would otherwise apply. A CPP proposal must be made in accordance with the methodologies and processes set out in the Input Methodology Determination.

Following the significant damage to its infrastructure caused by the series of earthquakes affecting the Christchurch area that started on 4 September 2010, Orion proposes to submit a CPP application to the Commission under the catastrophic event provisions of the Input Methodology Determination.

The Input Methodology Determination requires Orion to engage an independent engineer, to provide reports on certain aspects of that application. The reports are to be included in the CPP application to the Commerce Commission. In particular, a report is required on a quality standard variation from the default standards set by the Commission in accordance with clause 5.4.5(c) of the Input Methodology Determination.

This report has been prepared to meet the requirements for the variation in quality standards in accordance with clause 5.4.5(c) of the Input Methodology Determination

2.0 Requirements

Clause 5.4.5 specifies the Information on the proposed quality standard variations as follows.

Where a **CPP applicant** seeks a **quality standard variation**, the **CPP proposal** must contain the following information:

- (a) different values of either or both of-
 - (i) $\mu SAIDI$ and $\mu SAIFI$; and
 - (ii) $\sigma SAIDI$ and $\sigma SAIFI$,
 to those which would be determined in accordance with the methodology for calculating reliability limits specified in the **DPP determination**;
- (b) an explanation of the reasons for the proposed **quality standard variation**;
- (c) an **engineer's** report on the extent to which the **quality standard variation** better reflects the realistically achievable performance of the **EDB** over the **CPP regulatory period** based on either or both of-
 - (i) statistical analysis of past SAIDI and SAIFI performance; and

(ii) the level of investment provided for in proposed **maximum allowable revenue before tax**; ...

3.0 Review of Requirements

3.1 Context

Before reviewing the documentation provided by Orion it is appropriate to review the requirements noted in section 2.0 above in relation to the events that have lead to the request for a CPP.

The definition of a Catastrophic Event is found in sub Part 6 of COMMERCE ACT (ELECTRICITY DISTRIBUTION SERVICES INPUT METHODOLOGIES) DETERMINATION 2010 as follows: -

5.6.1 Catastrophic event

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.

It is understood that the events that impacted on the Orion network clearly fall into the above category, however it is not necessarily clear that the requirements of clause 5.4.5, as noted in section 2.0, necessarily reflect the event and its effects.

If consideration is given to a more common catastrophic event of a 30 year return snow fall/storm it would appear reasonable to be able fully follow the requirements specified of: -

“**quality standard variation** better reflectseither or both of-
 (i) statistical analysis of past SAIDI and SAIFI performance; and
 (ii) the level of investment provided for in proposed **maximum allowable revenue before tax; ...**”

3.2 Consideration and Comparison of Catastrophic Events

In the case of a snowstorm it is relatively straightforward to determine the exact level of damage to network components and to then develop the repair path line and thus it should be possible to reasonably accurately look at the historic SAIDI and SAIFI performance and use this to predict the overall network performance over the “clean-up” years.

For the major earthquake events suffered by the Orion network the situation is significantly different as identified in the following sections: -

3.2.1 Failure Rates

The extent of the damage to plant and equipment is not fully known, further, when compared to the snowstorm which affects a limited number of overhead components, the earthquakes are known to have damaged both overhead lines and cables, as well as transformers, switchgear and associated control and protection systems. It is likely that many components will have a higher failure rate in future years as some of the earthquake damage will have weakened items such that normal failure mechanisms (such as moisture ingress) will occur in places that would not normally be found or may occur at a faster rate than previously. Similarly it is likely that insulation or other components inside transformers, switchgear and controls may have suffered stress or even fractures that will cause future failures that would not otherwise be expected.

However, it is now 20 months since the major earthquake and the network has now been subjected to two winters including extensive periods of rain and also snow storms. It is reasonable to expect that the majority of the major incipient faults have now been triggered and that this, in association with ongoing works, will lead to a reduction in the incidents of faults causing large SAIDI outages

3.2.2 Loading Patterns

In the snowstorm case it can reasonably be assumed that the pre-existing network (and customers) will remain and the underlying changes in loading patterns can also be expected to continue. Conversely the actual network that will be required in several areas for Orion in future is not known and any previous load growth patterns are similarly unlikely to continue as before. The redevelopment of the CBD is at present yet to be confirmed and the type, size and expected loading of the buildings in the redeveloped areas can only be a matter of conjecture at this stage. Further the longer term population growth (and associated load growth) is unlikely to follow traditional historic trends with short term effects from additional people coming to Christchurch to assist in the re-building work, but a possible longer term reduction as existing residents opt to move to areas with a perceived lower earthquake risk. This latter trend has already been identified, but the duration and size of the departure in the longer term is unknown.

3.3.3 Network Configuration

For the snowstorm case it is expected that the network will be repaired so that that it is effectively identical to the pre-damage situation. For the present case Orion has identified that a simple rebuild of the existing network is not necessarily the most cost effective approach and has carried out studies to identify the theoretically most economically appropriate design approaches to take for network architecture.

3.3.4 Major Earthquake Risk

For the snowstorm case a one in thirty year return period may mean the impact of a similar storm the next year, but on average it is not expected for some 30 years and there is a relatively low risk of a snowstorm occurring during the CPP period. In the case of Christchurch the current views on the risk of a further severe earthquake are still a matter for debate with quite divergent views on the topic.

3.3.5 Data Homogeneity

For the case of the snowstorm the SAIDI and SAIFI in the years have been homogeneous and it should be possible to develop an accurate assessment of the damage to the network so it is reasonable to expect that a forward path for SAIDI and SAIFI can be predicted. In the present case the first earthquake caused a clear break point from historic trends, which were further distorted by the second and more damaging earthquake. With some areas of the network not yet restored at the request of the authorities the recent SAIDI and SAIFI figures are distorted by these ongoing forced outages and the date chosen to close off the generation of data from them.

It is therefore my view that the proposals put forward by Orion cannot be reviewed by a literal application of the requirements and that it is necessary to examine them from the perspective of the underlying philosophy of the requirements. This requires consideration of the engineering judgements made through the process to ensure they achieve the required result of better reflecting the realistically achievable performance.

Thus, for the review that follows, the approach taken has been to primarily consider if the proposals from Orion provide an appropriate trade-off between the proposed expenditure and resultant improvement in network performance from its present damaged state whilst also considering the approach taken to develop statistically valid data for SAIDI and SAIFI.

A further limiting factor when the comparison with a snowstorm event is considered is that of the physical ability to carry out works. It has already been noted that repair/replacement of much of the presently isolated CBD network is outside of Orion's control. However the wider issue is that of the repair/replacement of the rest of the network. For the snowstorm case it is reasonable to expect that additional resources can be applied over a relatively short time to bring the damaged part of the network back to pre-storm condition. Orion currently faces such a large amount of repair/replacement work that it is not realistic to complete it in a short space of time, even if funds were available. This is due to the level of resources (human, plant and materials) and also due to the

operational restrictions on the network which limit how many items of plant can be worked on at any given time.

Thus the Orion proposals must take account of what can physically be achieved in each year – assuming it were possible to decide what was to be done when still awaiting major decisions on the future network needs. This issue also creates problems when trying to estimate the SAIDI and SAIFI contributions to the total figures resulting from “organised shutdowns” – i.e. the necessity to close down a part of the network so as to permit the connection of new cables and plant to the network.

So this review becomes an examination of the Orion proposals to identify if they 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.

4.0 Review of Chapter 6

4.1 Targets

Orion proposes to return the overall network performance to that existing prior to the earthquakes, although this is not targeted to be achieved within the CPP period under consideration. Orion has carried out extensive studies and consultations over past years that have shown support for Orion’s targeted level of performance. It is of note that the network performance has been in the upper levels of that compared with other networks and both SAIDI and SAIFI have shown a long term steady improvement trend over the 10 years pre-earthquake. These results were achieved while also maintaining a position in the lowest price group of networks.

Considering the levels of expenditure it is considered reasonable to adopt the previous performance targets as a long term goal and to work towards these during this CPP period. With so many variables and unknowns this goal should be monitored in the light of actual costs and the achieved performance improvements to ensure they remain valid. The interval for review will need to be sufficiently long for a noticeable improvement in performance from the present situation.

4.2 Synthesising of Data

The overall approach adopted by Orion can be classified as synthesising the expected overall network SAIDI and SAIFI performance data from consideration of the expected contributions from the various components that make up the network. This approach recognises that the various components of the network will have various capital projects carried out that will improve their performance from the present, post earthquake, situation.

This approach allows for the economically sound decision to review the theoretically optimum network architectures and to use these as the basis of analysis for the overall repair/reinforcement proposals, but allowing for flexibility in individual cases where the existing network components appear able to continue to provide appropriate levels of service whilst not necessarily matching the theoretical ideal. In other words the approach looks to work towards the theoretical optimal designs

but adopting a pragmatic approach with existing network assets to ensure the best overall economic results.

The analysis has been carried out by considering the historic performance of network items broken down by voltage levels and identifying the various causes of outages. The historic data used for this analysis varies with sub-section under consideration, but in each case looks to distil out “clean” data for the analysis.

The data presented has been considered by outage cause and voltage class and appears to be realistic.

The improvement impact predicted on the performance figures from the planned projects similarly appears to be realistic and achievable for “normal” conditions each year. i.e. excluding the effects of a further major earthquake or other major event.

One aspect correctly identified by Orion regarding all of the rebuilding/replacement/reinforcement works is that of the increased risk of outages such activity is likely to cause. There are two sources of outages associated with the works, firstly the increased risk of outage due to error (such as a third party cable or line hits) but also the requirement to shut down supply to customers in order to carry out the new works.

This latter issue is particularly difficult in relation to the presently un-energised sections of the CBD as the condition of existing cables and plant is unclear, the new requirements are unknown and thus the process of establishing the replacement network is not known. If the building development plans allow, it may be possible to minimise the organised shutdowns, conversely it may result in additional interruptions. Orion is not able to control this situation as the decisions will be made by third parties including Christchurch Earthquake Recovery Authority (CERA), and the Stronger Christchurch Infrastructure Rebuild Team (SCIRT).

It is noted that the allowances for SAIDI are put at 11.7 minutes for the rural network and 1.8 minutes for the urban network, which, in the absence of any other suitable methodology are both based on historic performance levels¹. Whilst the rural network figure is considered to be appropriate in that operations remain similar post earthquakes to pre-earthquakes, this is not the case for the urban network including the presently disconnected CBD areas. It is considered that the SAIDI and SAIFI “allowance” should be increased for urban areas, in the absence of any other guidance or data it is suggested that the historic figures should be doubled.

4.3 Moving Targets

One specific deviation from the defined approach is that of proposing yearly values for SAIDI and SAIFI as opposed to proposing a single value for the reset period. This reflects the planned gradual improvement in network performance as it is rebuilt/replaced which will occur in an incremental way.

¹ Note that the urban figure may also be distorted by the change in work patterns after the first earthquake in the period up to the second earthquake.

By proposing such an approach Orion are setting a tougher target than if they had chosen to strictly follow the requirements for the DPP to an updated historical dataset, this being clearly illustrated in section 6.5.1 of their report. The performance measures calculated by this method would see their customers continuing to receive a level of performance significantly below that proposed under the gradually improving targets.

Based on a review of the components that build the synthesised targets it is considered reasonable to set year by year targets as supported by the data, this will provide all parties with a clearer picture of progress over the CPP period.

5.0 Review of Supporting Data

It was necessary to review several documents in addition to Chapter 6 as these detail aspects of the decision making process used by Orion in reaching their proposals. This section considers each of these items in turn.

5.1 Network Architecture Review – Subtransmission

This paper sets out a theoretical analysis of the options for the architecture of the subtransmission system (mainly 66kV) and seeks to establish the optimal solution which will provide the security level established as required to support the achievement of the overall performance figures.

It should be noted that Orion carried out a detailed Security Standard review in 2007 which generally endorsed the past design practices for most of the network. These standards considered the effect of High Impact Low Probability (HILP) events and reviewing the performance of the network after the first major earthquake confirmed the appropriateness of the level of resilience adopted. This was further tested by the second earthquake and also supported the resilience sought.

A purely theoretical “Greenfield” situation was developed and the various component costs introduced to develop the lowest cost topography. (Note that only variable costs were considered, common components between topologies were not included).

Having developed a theoretical approach to identifying the optimum architecture Orion has then sought to analyse how this can be applied to the existing system considering the expected re-development of the city. The options considered show that the proposed underlying levels of security appear to be achievable and to provide the most appropriate overall economic solution.

The recommendation is to adopt closed ring (N-1) topology with sufficient 66kV interconnection between the 66kV GXP’s to provide full support in the event of the total loss of a GXP and sufficient 11 kV tie capacity between adjacent zone substations to allow a substation’s complete load to be carried by two neighbouring zone substations as a general principle.

The ongoing development proposals as presented are therefore supported, noting that revisions will take place as better information becomes available, such as the actual load growth on an individual location.

It is noted, however, that all such analysis is dependent on the value applied to the cost of energy not supplied during an outage – the Value of Lost Load (VoLL). Whilst much work has been carried out around the world on this topic the current view, as supported by Orion, is that for accuracy in calculating the impact of an outage event a series of values for VoLL are required to reflect not only the difference in load types (Residential, Commercial, etc) but also the duration of the event. They propose to work with the Electricity Authority to develop a matrix approach to cover these items.

This proposal is fully supported as it should lead to improved decision making on individual projects by more accurately reflecting the economic cost to network customers of failures of supply. This will then help identify the optimum project and its timing to manage such events.

5.2 Network Architecture Review – Urban 11kV

This paper sets out a theoretical analysis of the options for the architecture of the Urban 11kV system. Factors taken into consideration include the initial purpose of 11kV feeders as the primary distribution system to distribution transformers and thus customers; and the provision of alternative supplies via the 11kV network to maintain supply to customers in the event of the loss of both 66kV circuits into a zone substation (as it did in multiple places during the earthquake) and notes that it also forms part of the overall philosophy for security.

The report drew on the detailed work carried out in 2007 and effectively provides an updated economic analysis of the various theoretical topologies. It is noted that in addition to establishment costs the costs of energy losses were also considered and this is considered appropriate.

One specific aspect that Orion has considered in detail is that of the type of 11kV distribution switchgear to be used in future. Traditionally Orion has used Magnefix Switching Units (MSU), however these have been in manufacture for some 40 years and safety standards for operators and the general public have changed, particularly in relation to Arc-Flash hazard. Further, as loads have grown they are being required to switch higher currents than in the past.

In summary this switchgear does not provide arc flash hazard protection that is now considered appropriate and whilst procedures and protective clothing etc can be used to allow existing equipment to remain in service no further units should be installed. (This is in agreement with decisions taken by other users of the equipment).

Orion are in the process of reviewing the range of options currently available, but the total cost of new options, including the installation costs, have not been fully established. The work in progress will establish these total costs which will then need to be used to re-check the economic analysis carried out on the 11kV architecture options. However, it is considered unlikely that there will be any major changes identified to the current proposals.

The overall proposals for Greenfield developments confirmed the present approach for the feeder configuration and local substation (kiosks) arrangements, subject to checking new 11kV switchgear costs. The ability to improve the network performance by the use of additional remote control equipment is noted for further analysis once the new switchgear costs are developed as is the benefit of adding remote indication of switchgear operation. Finally Orion notes that whilst the theoretical green fields approach should guide redevelopment of brown field areas the economics for conversions should be assessed on an area by area basis.

It is considered that the approach taken by Orion is fundamentally sound and pragmatic and the approach of continued review and individual economic analysis is fully supported.

5.3 Asset Management Plan.

The 2012 AMP summarises the overall plans by Orion for the restoration and development of its network taking into account the various reviews, etc covered above. The AMP sets the planned expenditure on both Capital and Maintenance, noting the interrelated nature of some expenditure.

The proposed levels of both expenditures has been provided and reviewed and it is considered they reflect an overall achievable set of targets based on current knowledge. It must be recognised that Orion faces a much greater level of uncertainty with many significant factors outside of its control as a result of the extensive damage to both the city and its network.

The proposed levels of expenditure appear to be realistically achievable, based on historic spending, including the past two years of emergency expenditure. Thus it is considered that materials and adequate numbers of appropriately qualified and trained staff are available to Orion to achieve the proposals. Further, the present proposals appear to reflect the expected renewal of property and infrastructure in the areas that suffered major damage

This is considered to further support the approach adopted of looking at annual incremental improvements and it must be expected that revisions to targets are likely to be required as the unknowns are addressed and more accurate data becomes available for review.

6.0 Conclusions

As established in section 3.0 of this report, for the situation faced by Orion it is not considered possible to apply the requirements for this Independent Engineer’s review strictly as written and thus the approach adopted was an examination of the Orion proposals to identify if they 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.

It is the reviewer’s opinion that Orion has demonstrated this within the limitations set by the lack of clarity around aspects of the rebuild on the CBD; Long term population trends; the unknown state of parts of the existing network asset and the associated impact on failure rates and the level of risk of further earthquake damage.

The approach adopted of reviewing theoretical optimum network architecture arrangements for both the sub-transmission and distribution networks is considered most appropriate as is the intention to check the application of these overall proposals when individual projects are analysed to review and ensure the most economic solution is found at the time of the decision being required.

Whilst not being possible to strictly follow the specified statistical analysis, Orion have adopted an approach to synthesise the projected data from realistic expectations of the performance of

individual sections of the overall network which appears to be carefully considered, and then the required approach to develop boundary values has been followed.

The proposed set of targets set by year for SAIDI and SAIFI – including their boundary values - are considered to be an appropriate way of addressing targeted performance as projects are carried out to repair/replace the severe damage suffered. Whilst recognising that the targets will be fixed for the determination period it is understood that Orion will review their planned projects in the light of actual performance compared to target as well as reflecting the improved knowledge on the effects of the earthquakes on plant and equipment.

This review 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. In comparison to the application of the DPP methodology the quality standard variation as proposed by Orion is considered to be notably better in reflecting the realistically achievable performance of the EDB (Orion) over the CPP regulatory period.

In summary, it is the reviewers opinion that Orion has chosen an appropriate balance between expenditure on the network and the expected improvement in performance. This recognises the present damaged state of parts of the network as well as the availability of resources for the work. The proposals are considered to better reflect the realistically achievable improvement in network performance than the standard methodology.

Appendix A: List of Documents Provided for Review

The following Documents were supplied to support the review: -

CPP Proposal Chapter 6 – Quality Standard Variation

Orion AMP 2012

Network Architecture Review – Subtransmission

Network Architecture Review – Urban 11kV Network – including Ring Main Unit Paper

Spreadsheets analysing expected performance of network sections

Paper presented to Orion Board on proposed quality standards for CPP application

Annual Budgets for proposed CAPEX and OPEX

Appendix 4

Satisfaction of CPP IM Information requirements

CPP Proposal Information Compliance Summary

CPP IM Information Requirements	CPP Proposal Reference
5.4.1 Application of this subpart	
(1) Subject to subclause (2), a CPP proposal must contain at least the information specified in this subpart.	
(2) For the purpose of subclause (1)- (a) where a CPP applicant seeks only a quality standard variation, its CPP proposal need only contain the information specified in clauses 5.4.2, 5.4.3, 5.4.4 and 5.4.5; and (b) where a CPP proposal is made in accordance with provisions in a DPP determination relating to the submission of CPP proposals in response to a catastrophic event, the information specified in clause 5.4.3 is not required.	n/a 4.1
5.4.2 Reasons for the proposal	
A CPP proposal must contain a-	
(a) detailed description of the CPP applicant's rationale for seeking a CPP; and (b) summary of the key evidence in the proposal supporting that rationale.	3.1 – 3.6, Appendix 1, Appendix 2, Appendix 3 3.8, Appendix 4
5.4.3 Information regarding priority of proposal	
(Not required – refer 5.4.1 (2)(b) above)	4.1
5.4.4 Duration of regulatory period	
Where a CPP applicant seeks a CPP of 3 years' or 4 years' duration- (a) the duration of the CPP sought must be stated in the CPP proposal; and (b) the CPP proposal must contain an explanation as to why that duration better meets the purpose of Part 4 of the Act than 5 years.	5.1 – 5.2
5.4.5 Information on proposed quality standard variation	
Where a CPP applicant seeks a quality standard variation, the CPP proposal must contain the following information:	
(a) different values of either or both of- (i) μ SAIDI and μ SAIFI; and (ii) σ SAIDI and σ SAIFI, to those which would be determined in accordance with the methodology for calculating reliability limits specified in the DPP determination;	6.1, 6.4, Appendix 9
(b) an explanation of the reasons for the proposed quality standard variation;	6.2, 6.3, 6.4, Appendix 6, Appendix 7, Appendix 8
(c) an engineer's report on the extent to which the quality standard variation better reflects the realistically achievable performance of the EDB over the	6.6, Appendix 3

CPP Proposal Information Compliance Summary

CPP IM Information Requirements	CPP Proposal Reference
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CPP regulatory period based on either or both of-

- (i) statistical analysis of past SAIDI and SAIFI performance; and
- (ii) the level of investment provided for in proposed maximum allowable revenue before tax; and

(d) 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.

6.5

5.4.6 Interpretation

(2) Any values and amounts used by a CPP applicant to determine the quantum of allowances, amounts, sums or values required by this section must be consistent with other information provided in accordance with this part.

Addressed through model and audit procedures

5.4.7 Proposed building blocks allowable revenue

(1) A CPP proposal must contain amounts for

(a) building blocks allowable revenue before tax for each disclosure year of the next period; and

7.3.1

(b) building blocks allowable revenue after tax for each disclosure year of the next period.

7.3.1

(2) A CPP proposal must contain all data, information, calculations and assumptions used to determine the amounts required by subclause (1), including but not limited to-

(a) amounts or forecasts of-

- (i) regulatory investment value; 7.3.2
- (ii) total value of commissioned assets determined in accordance with clause 5.3.2(3) 7.3.3
- (iii) total depreciation; 7.3.4
- (iv) total revaluation; and 7.3.5
- (v) other regulated income; 7.3.7

(b) all data, information, calculations and assumptions used to derive amounts or forecasts of TF_{VCA} , PV_{VCA} , TF , and TF_{rev} determined in accordance with clause 5.3.2(4); 7.3.6

(c) all data, information, calculations and assumptions used to derive the forecasts other regulated income provided pursuant to paragraph (a); 7.3.7

(c) forecast operating expenditure; and 7.3.8

(d) any proposed term credit spread differential allowance. 7.3.9

(3) A CPP proposal must contain the following information:

(a) actual other regulated income for each disclosure year of the current period; and 7.3.7

CPP Proposal Information Compliance Summary

CPP IM Information Requirements

CPP Proposal Reference

(b) data, calculations and assumptions demonstrating how the forecast of other regulated income provided pursuant to subclause (2)(a)(iv) is consistent with information provided in accordance with paragraph (a).

7.3.7

(4) All calculations, values and amounts required by this clause must be presented in a spreadsheet format which –

A list of the relevant spreadsheets which accompany this proposal is included in Section 7.10

(a) clearly demonstrates how building blocks allowable revenue before tax and building blocks allowable revenue after tax for each disclosure year of the next period have been derived using the formulae specified in clauses 5.3.2 and 5.3.3; and

(b) where data has been computed or derived from other values on the spreadsheet through the use of formulae, makes the underlying formulae accessible.

5.4.8 Maximum Allowable Revenues

(1) A CPP proposal must contain amounts for-

(a) maximum allowable revenue before tax for each disclosure year of the CPP regulatory period; and

7.2.1

(b) maximum allowable revenue after tax for each disclosure year of the CPP regulatory period.

7.2.1

(2) For the purpose of subclauses (1)(a) and (1)(b), the CPP applicant must -

(a) apply an X factor; and

7.2.4

(b) state the value of the X factor.

7.2.4

(3) For the purpose of subclause (2) the X factor is that defined in the CPP applicant's DPP determination, subject to subclause (4).

7.2.4

(4) For the purpose of subclause (3), a different X factor may be used provided that the CPP proposal contains an explanation and supporting evidence as to why it would better meet the purpose of Part 4 of the Act.

7.2.4

(5) A CPP proposal must contain all data, calculations and assumptions used to derive the forecast weighted average growth in quantities in accordance with clause 5.3.4(7), including-

7.2.5, Appendix 9 and 10

(a) a description of each demand group;

7.2.5

(b) the rationale for the selection of demand groups;

7.2.5

(c) the forecast growth in demand for each demand group;

7.2.5

(d) the basis for the forecast growth in demand for each demand group;

7.2.5

(e) evidence that the forecast growth in demand for each demand group is consistent with all other relevant demand forecasts included in the CPP

7.2.5

CPP Proposal Information Compliance Summary

CPP IM Information Requirements	CPP Proposal Reference
proposal;	7.2.5
(f) the basis for the assumptions used concerning the relative proportion of fixed and variable components in the prices charged to each demand group selected in paragraph (a);	7.2.5, Appendix 10
(g) reconciliation between the assumptions referred to in paragraph (f) and the calculation of notional revenue made pursuant to any requirement pursuant to s 53N of the Act (whether that requirement is contained in a s 52P determination or otherwise) relating to compliance with the price-quality path; and	7.2.5 and Appendix 10
(h) the basis for each weighting term.	7.2.5, Appendix 10
(6) For the purpose of this clause, 'DPP annual compliance statement' means the most recent annual compliance statement made by the supplier in accordance with a DPP determination.	7.2.5, Appendix 10
(7) All calculations and values required by this clause must be presented in a spreadsheet format which clearly demonstrates how maximum allowable revenue before tax and maximum allowable revenue after tax for each disclosure year of the CPP regulatory period have been derived from building blocks allowable revenue after tax and the variables in clause 5.4.7.	A list of the relevant spreadsheets which accompany this proposal is included in Section 7.10
(8) For the purpose of subclause (7), the spreadsheet must be provided in a format that-	A list of the relevant spreadsheets which accompany this proposal is included in Section 7.10
(a) shows clearly how the values required by subclause (1) were derived in accordance with the formulae specified in clauses 5.3.2 to 5.3.4; and	
(b) where data has been computed or derived from other values on the spreadsheet through the use of formulae, makes the underlying formulae accessible.	
5.4.9 Cost allocation information	
(1) Where a CPP applicant-	
(a) makes allocations of operating costs not directly attributable pursuant to clause 5.3.5(1); or	7.4.1
(b) determines opening RAB values pursuant to clause 5.3.6(1)(b)(ii), the CPP proposal must contain the information specified in subclause (2).	7.4.2
(2) For the purpose of subclause (1), the information is that specified in the applicable tables in Schedule B, subject to subclause (4), which tables comprise-	7.4.3
(i) Table 1, relating to allocation of the unallocated initial RAB value;	
(ii) Table 2, relating to allocation of the unallocated closing RAB value;	
(iii) Table 3, relating to allocation of operating costs not directly applicable;	
(iv) Table 4, relating to arm's-length deductions from regulated service asset values for assets with an unallocated closing RAB value in the last disclosure year of the current period; and	
(v) Table 5, relating to arm's-length deductions from operating costs.	

CPP Proposal Information Compliance Summary

CPP IM Information Requirements

CPP Proposal Reference

(3) In respect of-

7.4.3

(a) operating costs not directly attributable allocated to electricity distribution services in accordance with clause 5.3.5(2); or

(b) closing RAB values determined in accordance with clause 5.3.6(4), the CPP proposal must contain the information specified in Schedule C, subject to subclause (4), which tables comprise-

(c) Table 1, relating to allocation of the unallocated closing RAB value;

(d) Table 2 relating to allocation of operating costs not directly applicable;

(e) Table 3, relating to arm's-length deductions from regulated service asset values for assets with an unallocated closing RAB value at the end of the last year of the assessment period; and

(f) Table 4, relating to arm's-length deductions from operating costs.

(4) For the purpose of this clause-

7.4.3

(a) the information specified in the tables of the schedules referred to must be provided on spreadsheets; and

(b) where data has been computed or derived from other values on the spreadsheet through the use of formulae, all underlying formulae must be accessible.

5.4.10 Certification requirements

(1) Where any arm's-length deduction was applied for the purpose of this Section, the CPP proposal must contain certification by no fewer than 2 of the EDB's directors in the following terms, where words in bold bear the meanings specified in this determination:

7.4.1 and 7.4.2 (no arms length deduction has been made)

"I, [insert name], director of *[insert name of Supplier of services regulated under Part 4 of the Commerce Act]* certify that, having made all reasonable enquiry, my belief is that having had regard to the attached information *[information required by clause 5.4.9(2)]* for the purpose of the supplier's CPP proposal, it was appropriate to make the arm's-length deductions the amount and nature of which are detailed in the tables below, namely: Table 4 of Schedule B / Table 5 of Schedule B / Table 3 of Schedule C / Table 4 of Schedule C *[delete as appropriate]*."

(2) Where, in relation to regulated service asset values, OVABAA was applied for the purpose of this clause in accordance with Subpart 3 Section 2, the CPP proposal must contain certification by no fewer than 2 of the EDB's directors in respect of its application in the following terms, where words in bold bear the meanings specified in this determination:

7.4.1 and 7.4.2 (no arms length deduction has been made)

"

I, [insert name], director of *[insert name of Supplier of services regulated under Part 4 of the Commerce Act]* certify that, having made all reasonable enquiry, my belief is that having had regard to the attached information

CPP Proposal Information Compliance Summary

CPP IM Information Requirements	CPP Proposal Reference
<p>(being information required by clause 5.4.9(2)) for the purpose of the supplier's CPP proposal-</p> <p>(a) the attached information is accurate;</p> <p>(b) the OVABAA was applicable in accordance with clause 2.1.2; and</p> <p>(c) the following unregulated services would be unduly deterred had adjustments to allocations of regulated service asset values (in accordance with clause 2.1.5) not been made: <i>[list relevant unregulated services]."</i></p> <p>(3) Where, in relation to operating costs provided in a CPP proposal in accordance with subclause 5.4.8(1) and Schedule C, the OVABAA was applied, the CPP proposal must contain certification by no fewer than 2 of the EDB's directors in respect of application of the OVABAA in the following terms:</p> <p>"I, <i>[insert name]</i>, director of <i>[insert name of Supplier of services regulated under Part 4 of the Commerce Act]</i> certify that, having made all reasonable enquiry, my belief is that having had regard to the attached information (being information required by clause 5.4.9(2)) for the purpose of the supplier's CPP proposal-</p> <p>(a) the attached information is accurate;</p> <p>(b) the OVABAA was applicable in accordance with clause 2.1.2; and</p> <p>(c) the following unregulated services would be unduly deterred had adjustments to allocations of operating costs (in accordance with clause 2.1.5) not been made: <i>[list relevant unregulated services]."</i></p>	<p>7.4.1 and 7.4.2 (OVABAA has not been applied)</p>
<p>5.4.11 RAB roll forward information</p>	
<p>In respect of each disclosure year commencing after-</p>	
<p>(a) where disclosure has been made pursuant to an ID determination, the last disclosure so made; or</p>	<p>7.5.1</p>
<p>(b) where disclosure has not been made pursuant to an ID determination, the disclosure year 2009, to the last disclosure year of the next period, provide values, in accordance with Subpart 3 Section 2, for the-</p>	<p>7.5.1</p>
<p>(c) total opening RAB value; and</p>	<p>7.5.1</p>
<p>(d) sum of each of the following things:</p> <p>(i) forecast value of commissioned assets; and</p> <p>(ii) closing RAB values.</p>	<p>7.5.1 7.5.1</p>
<p>5.4.12 Depreciation information</p>	
<p>(1) In respect of each disclosure year of the CPP regulatory period, provide the information specified in this clause.</p>	<p>7.5.3</p>

CPP Proposal Information Compliance Summary

CPP IM Information Requirements	CPP Proposal Reference
(2) The sum of depreciation for each type of asset-	
(a) for which the proposed method of determining depreciation is the standard depreciation method; and	7.5.3, Appendix 15
(b) for which the proposed method of determining depreciation is something other than the standard depreciation method.	7.5.3
(3) For each type of asset to which subclause (2)(b) applies-	
(a) a description of the type of asset;	7.5.3
(b) a description of the proposed depreciation method;	7.5.3
(c) where the proposed asset life is different to the physical asset life, the proposed asset for the type of asset;	n/a
(d) where the proposed asset life for the type of asset is different to the physical asset life, the proposed remaining asset life;	n/a
(e) forecast depreciation over the asset life for the type of asset, including details of all assumptions made;	7.5.3
(f) forecast depreciation over the asset life for the type of asset determined in accordance with the standard depreciation method;	7.5.3
(g) 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; and	7.5.3
(h) a description of any consultation undertaken with consumers on the proposed depreciation method, including-	7.5.3, CPP application
(i) the extent of any consumer disagreement; and	
(ii) the EDB's view in response.	
(4) For each asset or type of asset for which a different physical asset life to the standard physical asset life is proposed-	n/a
(a) a description of the assets or types of asset;	n/a
(b) to which clauses 2.2.8(1)(c) and 2.2.8(1)(e)(v) apply, an engineer's report addressing the suitability of the proposed physical asset life; and	n/a
(c) any other evidence to demonstrate that the requirements of clause 2.2.8 in respect of the particular type of asset are met.	Appendix 16
5.4.13 Revaluation information	
(1) In respect of each disclosure year commencing after-	
(a) where disclosure has been made pursuant to an ID determination, the last disclosure so made; or	7.5.4

CPP Proposal Information Compliance Summary

CPP IM Information Requirements	CPP Proposal Reference
(b) where disclosure has not been made pursuant to an ID determination, the disclosure year 2009, to the last disclosure year of the next period provide the following things:	7.5.4
(c) sum of opening RAB values;	7.5.4
(d) forecast CPI for the last quarter of the disclosure year;	7.5.4
(e) forecast CPI for the last quarter of the preceding disclosure year; and	7.5.4
(f) revaluation rate.	7.5.4
5.4.14 Commissioned assets information	
(1) In respect of each disclosure year commencing after-	
(a) where disclosure has been made pursuant to an ID determination, the last disclosure so made; or	7.5.5
(b) where disclosure has not been made pursuant to an ID determination, the disclosure year 2009, to the last disclosure year of the next period, provide the-	7.5.5
(c) sum of value of commissioned assets; and	7.5.5
(d) sum of forecast value of commissioned assets,	7.5.5
in respect of each of the following groups of assets:	7.5.5
(e) assets-	
(i) acquired or intended to be acquired from a related company; or (ii) transferred from a part of the EDB that supplies unregulated services;	7.5.5 n/a
(f) assets-	
(i) acquired or intended to be acquired from another regulated supplier and used by that regulated supplier in the supply of regulated services; or	7.5.5
(ii) transferred or intended to be transferred from a part of the EDB that supplies other regulated services;	n/a
(g) network spares; and	7.5.5
(h) all other assets having a commissioning date or forecast to have a commissioning date in that period.	7.5.5
(2) In respect of each value provided in accordance with subclause (1) provide-	
(a) all data, information, calculations and assumptions used to derive it from	7.5.5

CPP Proposal Information Compliance Summary

CPP IM Information Requirements	CPP Proposal Reference
relevant data provided in the capex forecast; and	
(b) where capital contributions are taken into account in any value disclosed pursuant to subclause (1)-	7.5.5
(i) the amount of such capital contributions, with respect to asset types and quantities; and	
(ii) policies relevant to such capital contributions.	Available as supporting information
(3) In respect of each asset to which subclause (1)(e) applies, provide—	
(a) the name of the relevant person or other part of the EDB, as the case may be; and	7.5.5
(b) where the acquisition was or is intended to be from a related company, a description of the relationship between the EDB and that person.	7.5.5
(4) In respect of the likely vendor of each asset to which subclause (1)(f) applies, provide—	n/a
(a) the name of the vendor;	
(b) a description of each asset likely to be acquired from that vendor; and	
(c) the forecast closing RAB value of each asset in the vendor's regulatory asset base for the disclosure year in which the acquisition is intended.	
5.4.15 Asset disposals information	
(1) In respect of each disclosure year commencing after-	
(a) where disclosure has been made pursuant to an ID determination, the last disclosure so made; or	7.5.6
(b) where disclosure has not been made pursuant to an ID determination, the disclosure year 2009,	7.5.6
to the last disclosure year of the next period, in respect of each of the following groups of assets:	
(c) assets likely to be-	
(i) sold to a related company; or	7.5.6
(ii) transferred to another part of the EDB; and	7.5.6
(d) all other disposed assets, provide the-	7.5.6, 7.5.6
(e) sum of unallocated opening RAB values; and	7.5.6
(f) sum of opening RAB values.	7.5.6

CPP Proposal Information Compliance Summary

CPP IM Information Requirements	CPP Proposal Reference
(2) In respect of each asset to which the values provided pursuant to subclause (1) relate, provide—	
(a) the name of the relevant person or other part of the EDB, as the case may be; and	n/a
(b) where the disposal is proposed to be to a related company, a description of the relationship between the EDB and that person.	n/a
5.4.16 Works under construction information	
In respect of each disclosure year commencing after-	
(a) where disclosure has been made pursuant to an ID determination, the last disclosure so made; or	7.5.7
(b) where disclosure has not been made pursuant to an ID determination, the disclosure year 2009, to the last disclosure year of the next period, provide-	7.5.7
(c) opening works under construction;	7.5.7
(d) sum of capital expenditure;	7.5.7
(e) sum of value of commissioned assets but only to the extent that values are included in closing RAB values disclosed pursuant to an ID determination;	7.5.7
(f) sum of forecast value of commissioned assets but only to the extent that values are included in the sum of closing RAB values provided pursuant to clause 5.4.11(d)(ii); and	7.5.7
(g) sum of closing works under construction.	7.5.7
5.4.18 Period in respect of which tax information to be provided	
A CPP proposal must contain the information specified in this section in respect of each disclosure year commencing after-	
(a) where disclosure has been made pursuant to an ID determination, the last disclosure so made; or	7.6.1
(b) where disclosure has not been made pursuant to an ID determination, the disclosure year 2009,	7.6.1
to the last disclosure year of the next period, in accordance with Subpart 3 Section 3.	7.6.1
5.4.19 Regulatory tax allowance information	
(1) forecast regulatory tax allowance and particulars of how it was calculated	7.6.1
(2) other regulated income	7.6.1
(3) sum of discretionary discounts and customer rebates;	7.6.1

CPP Proposal Information Compliance Summary	
CPP IM Information Requirements	CPP Proposal Reference
(4) notional deductible interest and the cost of debt assumptions relied upon in its calculation	7.6.1
5.4.20 Tax losses information	
(1) amount of opening tax losses (if any) and particulars of how it was calculated	7.6.2
(2) information describing the nature and amounts of significant items giving rise to any opening tax losses	7.6.2
(3) information demonstrating that any opening tax losses arose from the supply of electricity distribution services	7.6.2
5.4.21 Permanent differences information	
(1) sum of positive permanent differences	7.6.3
(2) sum of negative permanent differences	7.6.3
(3) amounts and nature of items used to determine-	
(a) positive permanent differences; and	7.6.3
(b) negative permanent differences	7.6.3
5.4.22 Amortisation of initial differences in asset values information	
(1) opening unamortised balance of the initial differences in asset values by asset category	7.6.4
(2) amortisation in respect of the disclosure year	7.6.4
(3) average weighted remaining useful life of the assets relevant to calculation of the initial regulatory tax asset value	7.6.4
5.4.23 Amortisation of revaluations information	
(1) unamortised balance of revaluations to date	7.6.5
(2) adjusted depreciation	7.6.5
(3) average weighted remaining useful life of the assets used to determine the amortisation of revaluations	Error in IM – not relevant
(4) particulars of how the average weighted remaining useful life was calculated	Error in IM– not relevant
5.4.24 Deferred tax information	
(1) opening deferred tax	7.6.6
(2) analysis of temporary differences and other adjustments by nature that give rise to opening deferred tax value	7.6.6, 7.6.7, 7.6.4
(3) closing deferred tax	7.6.6

CPP Proposal Information Compliance Summary	
CPP IM Information Requirements	CPP Proposal Reference
(4) reconciliation of opening deferred tax to closing deferred tax by nature of temporary differences and other adjustments	7.6.6
5.4.25 Temporary differences information	
(1) description of the methodology and depreciation rates by asset category used to determine the forecast tax depreciation	7.6.8
(2) amounts and nature of other forecast temporary differences	7.6.7
(3) particulars of the calculation of the tax effect of temporary differences showing tax rates used	7.6.7
5.4.26 Regulatory tax asset value information	
(1) sum of tax asset values at the start of the disclosure year	7.6.8
(2) sum of tax asset values by asset category at the start of the disclosure year	7.6.8
(3) sum of regulatory tax asset values at the start of the disclosure year	7.6.8
(4) sum of regulatory tax asset values by asset category at the start of the disclosure year	7.6.8
(5) weighted average remaining tax life of assets and tax depreciation methodology employed, by asset category	7.6.8
(6) 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	7.6.8
(7) sum of regulatory tax asset values at the end of the disclosure year	7.6.8
(8) 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	7.6.8
5.4.27 Information regarding WACC	
(1) A CPP proposal must identify the 75th percentile estimate of WACC used for the purpose of clause 5.4.7(1).	7.7.1
(2) For the purpose of subclause (1), the identified 75th percentile estimate of WACC must be the amount most recently published by the Commission in accordance with clause 5.3.29 prior to submission of the CPP proposal corresponding to the EDB's proposed duration of the CPP regulatory period.	7.7.1
(3) Where a term credit spread differential allowance is proposed, a CPP proposal must contain all data, information, calculations, Bloomberg print-outs and assumptions used to determine any proposed term credit spread differential.	7.7.2
5.4.28 Capex, opex, demand and network qualitative information	

CPP Proposal Information Compliance Summary	
CPP IM Information Requirements	CPP Proposal Reference
The information specified in Schedule D must be-	
(a) contained in a CPP proposal; and	Section 9
(b) provided in accordance with the requirements of that schedule.	Section 9
5.4.29 Capex, opex, demand and network quantitative information	
(1) A CPP proposal must contain the information specified in the regulatory templates and that information must be-	8.2, 8.6, Schedule E, Tables 1-9
(a) in spreadsheet format whereby each item of data is linked between all cells to which it is relevant, irrespective of whether such cells are on the same or different tabs; and	A list of the relevant Schedule E spreadsheets which accompany this proposal is included in Section 8.7
(b) provided in accordance with the instructions specified in clause 5.4.30.	
(2) Regulatory templates means the tables included in Schedule E named-	
(a) Table 1: Top 5;	
(b) Table 2: Capex Summary;	
(c) Table 3: Opex Summary;	
(d) Table 4: Capex Project Programme;	
(e) Table 5: Opex Project Programme;	
(f) Table 6: Overheads;	
(g) Table 7: Unit rate escalators;	
(h) Table 8: Cost allocation A; and	
(i) Table 9: Cost allocation B.	
(3) Where data provided in accordance with subclause (1) has been computed or derived from other amounts or values on the spreadsheet through the use of formulae, the underlying formulae for the cells containing the data must be accessible.	A list of the relevant Schedule E spreadsheets which accompany this proposal is included in Section 8.7
(4) For the purpose of subclause (1), terms used in the regulatory templates must be interpreted in the same way as those terms are defined for the purpose of Schedule D.	
5.4.30 Instructions for completion of the regulatory templates	
(1) Provide the information specified in the Capex Project Programme and Opex Project Programme tables of the regulatory templates for each project and for each programme.	8.5.1, Tables 4 (capex) and 5 (opex), Appendix 20
(2) For the purpose of specifying the relevant capex category or opex category in accordance with subclause (1), where expenditure within each project or programme is relevant to more than one capex category or opex category-	8.5.3
(a) select the capex category or opex category that is most relevant based on the nature of the expenditure; or	
(b) redefine the project or programme into two or more new projects or programmes and reallocate the expenditure so as to resolve the overlap.	
(3) For the purpose of specifying the relevant service category in accordance with subclause (1), where expenditure within each project or programme is relevant to	8.5.2

CPP Proposal Information Compliance Summary

CPP IM Information Requirements	CPP Proposal Reference
more than one service category	
(a) select the service category that is most relevant based on the nature of the expenditure; or	
(b) redefine the project or programme into two or more new projects or programmes and reallocate the expenditure so as to resolve the overlap.	
(4) For the purpose of subclause (1), the total Project/Programme amounts provided in the Asset Category sub-table must reconcile to the total Project/Programme amounts provided in the Project Costs by Source sub-table.	8.5.1 - 8.5.5, Tables 4 and 5
(5) Provide the information specified in the Overheads table of the regulatory templates in respect of general management, administration and overheads opex.	8.5.3, Table 6
(6) Provide the information specified in the Unit rate escalators table of the regulatory templates for each unit rate for which an escalator has been applied.	8.5.6, Table 7 (for each escalator)
(7) Provide the information specified in the Top 5 table of the regulatory templates-	8.5.1, Table 1
(a) in respect of projects or programmes meeting paragraph (a) or (b) of the definition in clause D1 of Schedule D of identified programme; and	
(b) using the information provided in accordance with subclause (1).	
(8) Provide the information specified in the Capex Summary and Opex Summary tables of the regulatory templates using the information provided in accordance with subclause (1).	8.3, Tables 2, 3a), b) and c)
(9) Where clause 5.3.5(2) applies, provide the information specified in the Cost allocation B table of the regulatory templates.	5.3.5(2) does not apply
5.4.31 Transitional information format provisions	
(1) For CPP proposals made on or before 31 March 2016, the CPP proposal may contain actual and forecast expenditure information-	
(a) relating to the current period and next period using the opex categories and capex categories; or	8.5.3
(b) in accordance with the -	
(i) CPP applicant's own opex categories and capex categories in respect of the current period and next period; and	8.5.3
(ii) opex categories and capex categories in respect of the next period.	8.5.3
(2) For the avoidance of doubt, where information is provided in accordance with subclause (1)(b), project or programme total expenditures in each disclosure year of the next period must be consistent between the forecasts.	8.5.3
D2 Instructions relating to provision of information	
(1) A CPP proposal must-	

CPP Proposal Information Compliance Summary	
CPP IM Information Requirements	CPP Proposal Reference
(a) assemble all information that this Schedule requires in a section of the CPP proposal entitled “Capex/Opex/Demand Qualitative Information”; and	Section 9
(b) contain a table that, in respect of each clause of this schedule-	
(i) provides a reference to the place where, in the Capex/Opex/Demand Qualitative Information section of the CPP proposal, a response is provided; and	9.2.1
(ii) gives the title and page reference to any separate document identified in response, including in the case where the document in question is provided in the CPP proposal.	9.2.1
(2) Where information provided in accordance with these requirements differs from the most recent information provided by the EDB to the Commission in accordance with any obligation under Part 4 of the Act, a CPP proposal must-	9.2.2
(i) identify the differences; and	
(ii) give reasons for such differences.	
(3) Where information required by this Schedule is omitted from a CPP proposal, the CPP proposal must contain an explanation for each such omission.	9.2.3
(4) A CPP applicant may, without provision of additional information, reproduce information from its asset management plan in response to a requirement of this Schedule, subject to subclause (5).	Appendix 23
(5) For the purpose of subclause (4), reproduction of such material is only permitted where the relevant section of the asset management plan clearly and succinctly provides the required information, without the need for analysis or interpretation on the part of the verifier or the Commission.	Appendix 23 provides references and explanations
(6) For the avoidance of doubt-	
(a) the content of the CPP proposal as initially provided to the verifier will not include information required by this schedule in relation to projects or programmes falling under paragraph (c) of the definition in this schedule of identified programme; and	Noted
(b) such information-	
(i) need only be provided to the verifier upon the verifier's request; and	Noted
(ii) is required to be included in the CPP proposal as provided to the Commission.	Throughout sections 8 and 9
D3 Qualitative Information	Table included in section 9.2.1 provides the compliance references
(1) Provide-	
(a) all policies relied upon in whole or in part in preparing the response to-	
(i) this schedule; and	9.4, 9.3.1, 9.5.1, 9.5.2, 9.5.3, 9.5.6, Appendix

CPP Proposal Information Compliance Summary

CPP IM Information Requirements	CPP Proposal Reference
(ii) any other requirement of Subpart 4 Section 8 of Part 5; and	21
(b) where the rationale is not already included in the policies themselves, the rationale for the policies provided in accordance with paragraph (a), including any consultants' reports relied upon in preparing the policies.	9.4.1, 9.4.2, 9.4.3, 9.5, Appendix 21, Appendix 24
(2) Identify all consultants' reports commissioned for the purpose of preparing the capex forecast or opex forecast.	9.3.1, Appendix 22
(3) Where information from the CPP applicant's asset management plan has been included in the CPP proposal in response to a requirement of this clause, provide an index of explicit references to the sections and paragraphs of the asset management plan relied upon.	9.4.1, 9.5.1 - 9.5.6, 9.3.2, Appendix 23
D4 Categorisation of services	
For each service category relevant to the electricity distribution services provided by the EDB, provide-	
(a) a description of the EDB's services that fall within it, including- <ul style="list-style-type: none"> (i) its key service features and specifications; (ii) the identity of the intended consumers of the services; (iii) the processes used to determine the features and specifications of each service; and (iv) any material changes to the services proposed for the next period; 	9.6.1 – 9.6.10, Appendix 25
(b) the service measures, including a description as to how these have been defined, relating to- <ul style="list-style-type: none"> (i) categories of consumers; (ii) asset performance, asset efficiency and effectiveness; (iii) efficiency of the EDB's business activities; and (iv) the EDB's obligations; 	9.6.1-9.6.10
(c) a corresponding target service level for each service measure;	
(d) a description as to how each target service level-	9.6.11
<ul style="list-style-type: none"> (i) was determined, including a description of any consumer consultation used to specify it; and (ii) relates to the EDB's relevant policies; 	9.6.11
(e) a comparison and evaluation of each actual service level achieved for each disclosure year in the current period against each relevant target service level for each relevant service measure, including explanations for all significant variances and, for each significant variance, an explanation of the action being taken or proposed to improve performance; and	9.6.12
(f) details of all proposed changes to the target service levels for each service measure, including-	9.6.1-9.6.11
<ul style="list-style-type: none"> (i) the rationale for all proposed changes with reference to relevant 	

CPP Proposal Information Compliance Summary	
CPP IM Information Requirements	CPP Proposal Reference
consumer demands and the EDB's obligations; and (ii) a description of how the proposed changes were taken into account in preparing the CPP proposal.	
D5 Network asset information	
1) Provide details of the EDB's existing network assets including-	
(a) a high-level description of the distribution area that includes-	9.7.2
(i) identification of the distribution area(s) covered; (ii) identification of large consumers that have a significant impact on network operations or asset management priorities; (iii) a description of the load characteristics for different parts of the network; and (iv) the peak demand and total electricity delivered in each disclosure year of the current period, broken down by geographically non-contiguous network, if any;	
(b) a description of the existing network configuration, including-	9.7.3
(i) identification of bulk electricity supply points and any embedded generation with a capacity greater than 1 MW; (ii) existing firm supply capacity and current peak load of each bulk supply point; (iii) a description of the sub-transmission system fed from the bulk supply points, including identification and capacity of zone substations and the voltage of the sub-transmission network; (iv) identification of the sub-transmission security levels of individual zone substations , eg, n, n-1, n-2, and the rationale for the use of each level used; and (v) a description of the distribution system, including the extent to which it is underground	
(c) a brief description of the network's distribution substation arrangements;	9.7.4
(d) a description of the low voltage network, including the extent to which it is underground;	9.7.5
(e) an overview of secondary assets such as ripple injection systems, SCADA and telecommunications systems;	9.7.6, 9.5.4
(f) a description of the existing network assets by asset category, including-	9.7.3, 9.7.7, Asset Management Reports (NW70.00.22 – NW70.00.44)
(i) voltage levels; (ii) a description and quantity of assets; (iii) age profiles; (iv) a discussion of the condition of the assets, further broken down as appropriate, including historic failure rates; and (v) identification of any relevant systemic issues that may lead to the need to prematurely replace assets or parts of assets;	
(g) the sum of regulated service asset values by asset category consistent with those most recently disclosed by the EDB prior to making the CPP application pursuant to the Electricity Disclosure (Information Requirements) 2008 or an ID determination; and	9.7.8
(h) at the EDB's option, a sum of regulated service asset values by any asset	Appendix 26

CPP Proposal Information Compliance Summary	
CPP IM Information Requirements	CPP Proposal Reference
category sub-category (as 'sub-category' is defined by the EDB);	
(2) For the purpose of subclause (1)-	
(a) where information is based on estimates, this must be explicitly stated;	9.5.4, 9.5.5
(b) quantities of assets must be presented in a way that clearly describes the size of the regulatory asset base, but need not include detailed lists or schedules as would be included in a complete asset register or inventory; and	refer above sections
(c) 'geographically non-contiguous network' means a network that is physically separate from another network except where-	9.7.2
(i) its total circuit length capable of conveying electricity at a voltage equal to or greater than 3.3 kilovolts is shorter than 25 kilometres;	
(ii) it conveyed fewer than 20 gigawatt hours of electricity in the most recent disclosure year prior to submission of the CPP application;	
(iii) its lines are not connected, whether directly or indirectly, to the national grid (as 'national grid' is defined in s 5 of the Electricity Industry Act 2010); or	
(iv) it conveys electricity to fewer than 2000 ICPs (as 'ICP' is defined in s 54D(2) of the Act).	
D6 Demand, consumer numbers and generation forecasts	
(1) For each key assumption relating to maximum demand, electricity supplied, consumer numbers, embedded generation and distributed generation-	
(a) explain how it was relied upon in the CPP proposal;	9.8.6
(b) provide, describe and explain the methodology used to prepare the relevant forecasts (to at least zone substation level) relating to demand forecasts for each disclosure year in the next period, including details of-	9.8.1, 9.8.2, 9.8.3, 9.8.4, 9.8.5
(i) any sensitivity analysis undertaken;	
(ii) any weather normalisation methodology used and how weather data has been used; and	
(iii) the models used (including each model's key inputs and assumptions); and	
(c) provide-	
(i) an outline of the treatment of very large loads, uncertain loads and significant loads transferred, or expected to be transferred, between different parts of the network (e.g. between zone substations and/or between feeders);	9.8.6
(ii) assumptions of consumer numbers in total and by the consumer categories used by the EDB;	9.8.2, 9.8.3
(iii) assumptions of energy volumes supplied to consumers by each category referred to in sub-paragraph (ii);	9.8.6
(iv) assumptions relating to average consumer energy usage by each category referred to in sub-paragraph (ii);	9.8.6
(v) details of the location, type and size of any embedded generators and assumptions relating to the impact they may have on network forecasts;	9.8.6
(vi) details of the location, types and aggregate levels of any distributed generation and assumptions relating to the impact they may have on network forecasts; and	9.8.6
(vii) details of the effect that any demand management systems or initiatives may	9.8.2

CPP Proposal Information Compliance Summary

CPP IM Information Requirements	CPP Proposal Reference
have on network forecasts.	
(2) Explain-	
(a) the extent to which the forecasting methodology used is consistent with and has taken into account historical observations;	9.8.6
(b) whether forecast data is internally consistent at and between each level of aggregation down to at least the zone substation level; and	9.8.6
(c) the extent to which the forecasting methodology used is consistent with the methodology used to derive the forecast quantities as required by clause 5.3.4(7).	9.8.6 and 7.2.3
D7 Capital expenditure	
(1) For each capex category included in the capex forecast-	
(a) provide an overall description including the aims and objectives of the capex category;	9.11.1, 9.11.2, 9.11.3, 9.12, 9.13-9.17
(b) provide an explanation as to its deliverability, with reference to factors likely to affect the capex category as a whole; and	9.13-9.17, 9.11.2, 9.11.3
(c) identify all relevant documents, policies and consultant's reports that were taken into account in preparing the capex forecast.	9.13-9.17
(2) For each identified programme included in the capex forecast-	
(a) provide an overall description including the aims and objectives of the identified programme;	9.13.1, 9.15.1, 9.16.1, Appendix 36 and 37
(b) provide an explanation as to its deliverability, with reference to factors likely to specifically affect that identified programme;	
(c) provide details of all contingency factors provided for, including how they were calculated and what uncertainties they account for;	
(d) state-	
(i) each relevant key assumption;	
(ii) each relevant obligation; and	
(iii) any step change and its effect on the capex forecast for the identified programme;	
(e) explain all departures from any conclusions and recommendations contained in each consultant's report identified in accordance with subclause (1)(c); and	
(f) explain the methodology used to generate the capex forecast for the identified programme, including but not limited to details regarding-	
(i) any cost benchmarking undertaken by or for the EDB;	
(ii) internal historical cost trends (for specific asset categories) relied upon;	
(iii) material changes to work backlogs;	

CPP Proposal Information Compliance Summary

CPP IM Information Requirements	CPP Proposal Reference
<p>(iv) all network alternative projects and/or programmes considered; (v) all non-network alternatives that were considered, whether adopted or not, and the reason(s) for rejecting them; (vi) all cost-benefit analyses undertaken; (vii) all contingency factors provided for, including how they were calculated and what uncertainties they account for; and (viii) any step change from historical costs in any cost component included in the identified programme and its effect on the capex forecast.</p> <p>(3) For each policy identified in response to subclause subclause (1)(c), explain-</p> <p>(a) how it was taken into account and complied with; and</p> <p>(b) how relevant planning standards have been incorporated.</p>	<p>9.13.1, 9.15.1, 9.16.1, Appendix 21, Appendix 36 and 37</p>
<p>(4) For each key assumption identified in accordance with subclause (2)(d)(i)-</p> <p>(a) provide the method and information used to develop the assumption; and</p> <p>(b) explain how the assumption has been applied and its effect on the capex forecast.</p>	<p>9.13.1, 9.15.1, 9.16.1, Appendix 36 and 37</p>
<p>(5) Where any identified programme, other than a project or programme to be undertaken for the foreseeable future, is forecast to terminate after the end of the next period, in addition to the information required by subclause (2), provide any additional information relevant to capex forecast to the end of the identified programme.</p>	<p>9.13.1, 9.15.1, 9.16.1, Appendix 36 and 37</p>
<p>(6) For each project and programme (other than identified programmes) included in the capex forecast-</p> <p>(a) explain-</p> <p>(i) how each relevant policy identified in response to subclause (1)(c) was taken into account and complied with; and</p> <p>(ii) how the relevant planning standards have been incorporated; and</p> <p>(b) provide details of all contingency factors provided for, including how they were calculated and what uncertainties they account for.</p>	<p>9.13.12, 9.14.1, 9.15.2, 9.17, Appendix 21</p> <p>9.13.12, 9.14.1, 9.15.2, 9.17</p>
<p>D8 System growth capital expenditure information</p>	
<p>For system growth capex, provide-</p>	
<p>(a) a description of the relevant planning standards and relevant key assumptions;</p>	<p>9.13.6</p>
<p>(b) a description of the prioritisation methodology adopted for system growth projects and programmes;</p>	<p>9.13.4</p>
<p>(c) details of the specific network locations where constraints are expected due to forecast load increases;</p>	<p>9.13.7, Appendix 29</p>

CPP Proposal Information Compliance Summary

CPP IM Information Requirements	CPP Proposal Reference
(d) relevant policies for purchasing land and easements for future use;	9.13.5
(e) relevant policies on embedded and distributed generation;	9.13.9
(f) relevant policies on non-network solutions;	9.13.10
(g) where rationale is not already included in the policy documents, rationale for the policies provided in accordance with paragraphs (d) to (f);	Appendix 21
(h) an analysis of the network and non-network development options available;	9.13.9
(i) details of the planning decisions made to meet each relevant target service level; and	9.13.6
(j) a description and identification of the system growth programme including-	9.13
(i) provisions made in respect of embedded and distributed generation and non-network solutions;	9.13.9
(ii) actions to be taken, including clear linkages to the forecast expenditures in each of the associated projects and programmes;	9.13.11, 9.13.12
(iii) a detailed description of each project in the capex forecast that has commenced or is committed; and	9.13.11, 9.13.12
(iv) a description of each project or programme that is not committed but is planned to commence in the next period, the information being provided to be commensurate with the project's or programme's current status in the planning process.	9.13.11, 9.13.12
D9 Asset replacement and renewal capital expenditure information	
(1) For asset replacement and renewal capex provide-	
(a) a description of the relevant policies and key assumptions relating to the circumstances in which capex should be incurred based on-	9.7.1, 9.15
(i) the age or reliability profile of an asset by comparison with the condition of an asset and vice versa; and	
(ii) replacement of an asset rather than renewing it and vice versa;	
(b) where rationale is not already included in the policy documents, the rationale for the policies and key assumptions provided in accordance with paragraph (a);	Appendix 21
(c) any asset replacement models developed by or for the EDB to determine asset replacement and renewal capex, including-	9.15
(i) all supporting documentation for the models used; and	
(ii) any other relevant considerations; and	
(d) a description and identification of replacement and renewal programmes or actions to be taken for each asset category.	9.15.1, 9.15.2
(2) Explain whether and how the matters provided and identified in accordance with subclause (1)-	9.15

CPP Proposal Information Compliance Summary

CPP IM Information Requirements	CPP Proposal Reference
<p>(a) were taken into account in the capex forecast; and</p> <p>(b) affected forecast asset replacement and renewal capex by comparison with the equivalent actual capex incurred.</p>	
<p>(3) Explain how any proposed system growth associated with the replacement of assets before the end of their asset life has been taken into account in the asset replacement and renewal capex for the next period.</p>	9.15
<p><i>D10 Reliability, safety and environment capital expenditure information</i></p>	
<p>For reliability, safety and environment capex-</p>	
<p>(a) describe the implications (including timing) of complying with any-</p> <ul style="list-style-type: none"> (i) new obligation; or (ii) substantive amendment to any current such obligation that is reasonably anticipated to occur during the next period, concerned with safety or environmental protection relevant to the supply of electricity distribution services by the EDB; 	9.14
<p>(b) explain how these new obligations or substantive amendments to obligations have been taken into account in the CPP proposal;</p>	9.14
<p>(c) describe-</p> <ul style="list-style-type: none"> (i) the relevant risk management policies; (ii) risk assessments and risk mitigation or risk prevention measures employed during the current period, including those pursuant to or in response to an obligation or a step change to an obligation; and (iii) all risk mitigation measures identified and proposed to be deployed in the next period, including methods, details and conclusions of risk assessments and details of emergency response and contingency plans; <p>and</p>	9.14, 9.9.1 9.9.2 9.9.3, 9.9.4 9.9.3, 9.9.5
<p>(d) where rationale is not already included in the policy documents provide the rationale for the policies provided in accordance with paragraph (c).</p>	Appendix 21
<p><i>D11 Non-system fixed assets capital expenditure information</i></p>	
<p>For non-system fixed assets capex in the capex forecast provide the rationale for the expenditure in the largest two of the following expenditure categories by dollar value:</p>	
<ul style="list-style-type: none"> (a) asset management systems; (b) information and technology systems; (c) motor vehicles; (d) office buildings, depots and workshops; (e) office furniture and equipment; and (f) tools, plant and machinery. 	9.17, 9.17.1

CPP Proposal Information Compliance Summary

CPP IM Information Requirements

CPP Proposal Reference

D12 Operating and maintenance expenditure

(1) For each opex category included in the opex forecast-	9.11.1, 9.11.2, 9.11.3, 9.18, 9.19 – 9.23
(a) provide an overall description including the aims and objectives of the opex category;	
(b) provide an explanation as to its deliverability, with reference to factors likely to affect the opex category as a whole; and	
(c) identify all relevant documents, policies and consultants' reports that were taken into account in preparing the opex forecast.	Appendix 21
(2) For each identified programme included in the opex forecast-	
(a) provide-	9.19.5, 9.20.6, 9.22.1, 9.23.5, Appendix 36 and 37
(i) an overall description including the aims and objectives of the identified programme;	
(ii) an explanation as to its deliverability, with reference to factors likely to affect that identified programme specifically; and	
(iii) details of all contingency factors provided for, including how they were calculated and what uncertainties they account for;	
(b) identify-	
(i) each relevant key assumption;	
(ii) each relevant obligation; and	
(iii) any step change and its effect on the opex forecast for the identified programme; and	
(c) explain-	
(i) whether a base year approach was used in forecasting, and if so, identify the base year used and, if it is not a year in the current period (for which data will have been provided), provide the relevant data from that base year;	
(ii) all departures from any conclusions and recommendations contained in each consultant's report identified in accordance with subclause (1)(c);	
and	
(iii) the methodology used to generate the opex forecast for the identified programme.	
(3) For the purpose of subclause (2)(c)(iii), such methodology must include, as a minimum, details regarding-	
(a) any cost benchmarking undertaken by or for the EDB;	9.19.5, 9.20.7, 9.21.6, 9.22.1, 9.23.5, Appendix 27 and 28
(b) internal historical cost trends (for specific asset categories) relied upon;	
(c) descriptions of inspections, tests and condition monitoring carried out and the intervals at which they were done;	

CPP Proposal Information Compliance Summary

CPP IM Information Requirements	CPP Proposal Reference
<p>(d) material changes to work backlogs;</p> <p>(e) alternative programmes considered;</p> <p>(f) all cost-benefit analyses undertaken;</p> <p>(g) all contingency factors provided for, including how they were calculated and the uncertainties they account for;</p> <p>(h) any step change from historical costs in any cost component included in the identified programme and its effect on the opex forecast; and</p> <p>(i) how the service measures identified in accordance with clause D4(b) were taken into account.</p>	
<p>(4) For each relevant policy identified in response to subclause (1)(c), explain-</p> <p>(a) how it was taken into account and complied with; and</p> <p>(b) how the relevant planning standards were incorporated in it.</p>	9.19 - 9.23, Appendix 21
<p>(5) For each key assumption identified in accordance with subclause (2)(b)(i), explain-</p> <p>(a) the method and information used to develop the assumption; and</p> <p>(b) how the assumption has been applied and its effect on the opex forecast.</p>	9.19.5, 9.20.7, 9.21.6, 9.22.1, 9.23.5
<i>D13 General management, administration and overheads operating expenditure category</i>	
<p>(1) For the general management, administration and overheads opex category-</p> <p>(a) identify-</p> <p>(i) each relevant key assumption;</p> <p>(ii) each relevant obligation; and</p> <p>(iii) any step change and its effect on the opex forecast for this category; and</p> <p>(b) explain-</p> <p>(i) whether a base year approach was used in forecasting, and if so, identify the base year used and, if it is not a year in the current period (for which data is required to be provided in a CPP proposal), provide the relevant data from that base year; (ii) all departures from any conclusions and recommendations contained in each consultant's report identified in accordance with clause D12(1)(c); and</p> <p>(iii) the methodology used to generate the opex forecast for this category.</p>	9.23, Appendix 28
<p>(2) For the purpose of subclause (1)(b)(iii), such methodology must include, as a</p>	9.23

CPP Proposal Information Compliance Summary

CPP IM Information Requirements	CPP Proposal Reference
<p>minimum, details regarding-</p> <ul style="list-style-type: none"> (a) any cost benchmarking undertaken by or for the EDB; (b) internal historical cost trends relied upon; (c) all contingency factors provided for, including how they were calculated and the uncertainties they account for; and (d) the effect of any step change on the costs in the general management, administration and overheads opex category. <p>(3) For each relevant policy identified in the response to clause D12(1)(c) explain how it was taken into account and complied with.</p> <p>(4) For each key assumption identified in accordance with subclause (1)(a)(i), explain-</p> <ul style="list-style-type: none"> (a) the method and information used to develop the assumption; and (b) how the assumption has been applied and its effect on the opex forecast for this opex category. 	<p></p> <p>9.23.4, Appendix 21</p> <p>9.23</p>
<p><i>D14 Operating expenditure projects and programmes</i></p>	
<p>For each project and programme (other than identified programmes) included in the opex forecast -</p> <ul style="list-style-type: none"> (a) explain how each of the relevant policies identified in the response to clause D12(1)(c) was taken into account and complied with; (b) explain how the relevant planning standards have been incorporated; and (c) provide details of all contingency factors provided for, including how they were calculated and what uncertainties they account for. 	<p>9.23, Appendix 21</p>
<p><i>D15 Self-insurance</i></p>	
<p>(1) For any proposed self-insurance allowance-</p> <ul style="list-style-type: none"> (a) provide- <ul style="list-style-type: none"> (i) a description of the uncertainties covered by the allowance; (ii) the methodology used to calculate the self-insurance risk premium (e.g. probability multiplied by consequence); (iii) a report on the calculation of each self-insurance risk premium from an actuary who is qualified to provide such advice; and (iv) any quotes obtained from external insurers; and (b) explain why compensation should be provided for the uncertainty. 	<p>9.23.7, Appendix 11</p> <p>n/a</p>
<p>(2) In respect of each quote provided in accordance with subclause (1)(a)(iv)-</p> <ul style="list-style-type: none"> (a) state- <ul style="list-style-type: none"> (i) the amount insured for which the quote related (if not included in 	<p>n/a</p>

CPP Proposal Information Compliance Summary	
CPP IM Information Requirements	CPP Proposal Reference
<p>the quote itself); (ii) the annual premium payable or paid by the EDB; (iii) the size of any deductible; (iv) the terms and conditions of the insurance; and (v) why it is not considered suitable.</p>	n/a
<p>(3) Explain whether and, if so, how the costs of remediating the effects of each uncertainty for which the allowance is sought may be recovered through any other mechanism.</p>	
D16 Controllable opex	
<p>For each disclosure year of the next period provide-</p> <p>(a) a description of the types of opex comprised in the forecast for controllable opex; and (b) justification for why the opex referred to in paragraph (a) should be determined as controllable opex, including a description of how the EDB is able to control the amount of opex over the CPP regulatory period.</p>	9.24
D17 Related parties	
<p>(1) Identify and describe all related parties in respect of whom costs are disclosed in accordance with the regulatory templates.</p>	9.25.1
<p>(2) For each person to whom subclause (1) applies identify each project or programme with which he, she or it is associated.</p>	9.25.2
<p>(3) For each person to whom subclause (1) applies, describe, in respect of each relevant project and programme the-</p> <p>(a) nature of the services undertaken by that person; and (b) the date and term of the contract in respect of that service.</p>	9.25.2, Appendix 31
<p>(4) For each service identified in accordance with subclause (3)(a)-</p> <p>(a) provide a description of the tendering process used to procure the service;</p>	9.19.3, 9.25.3, Appendix 32
<p>(b) identify all relevant documents used to tender for its provision, including but not limited to requests for tender and tender submissions; and</p>	9.25.3
<p>(c) explain-</p> <p>(i) why that service is outsourced instead of being undertaken by the EDB itself; (ii) whether the services procured are provided under a discrete contract or provided as part of a broader operational contract (or similar); (iii) whether the service was procured on a genuinely competitive basis and if not, why not; and (iv) whether the service (or any component thereof) was sub-contracted to another provider.</p>	9.11.2, 9.19.3, 9.25.3

CPP Proposal Information Compliance Summary

CPP IM Information Requirements	CPP Proposal Reference
(5) For each contract identified in accordance with subclause (3)(b), identify methodologies, consultants' reports, or assumptions used to determine components of the costs included in the contract price.	9.11.2, 9.19.3, 9.25.1
D18 Unit costs and expenditure escalators	
(1) For each key assumption that is a unit rate-	9.26.1, 9.26.2
(a) identify-	
(i) source material from which it was derived;	
(ii) the date it was developed; and	
(iii) the historical unit rates adopted for key items of plant and equipment for the capex forecast and the opex forecast; and	
(b) explain-	
(i) how it was developed with reference to the responses to paragraph (a); and	
(ii) whether, and if so an explanation as to why, its quantum is reasonable.	
(2) For each key assumption that is a labour or materials escalator-	9.26
(a) provide the class of labour and materials to which each escalator relates;	9.26.3
(b) provide-	
(i) the base year and the labour and materials unit rates for that year;	n/a
(ii) the escalator used in percentage terms for each year from the base year to the end of the next period;	9.26.3 – 9.26.5
(iii) the quantum of the labour costs in the capex forecast and the opex forecast which is the result of application of the labour escalator;	9.26.6
(iv) the quantum of the materials costs in the capex forecast and the opex forecast which is the result of application of the materials escalator; and	9.26.6
(v) confirmation of whether the escalator used is expressed in real or nominal terms and, if real, the indexation assumptions used; and	9.26.5
(c) explain-	
(i) the methodology underlying the calculation of each escalator, including sources, data conversions and the use of any assumptions, including lags;	9.26.3 – 9.26.5, Appendices 33 - 35
(ii) the weightings given to each escalator and how these weightings were developed, including any assumptions;	
(iii) whether the same expenditure escalators have been used in the capex forecast and opex forecast;	
(iv) where the response to sub-paragraph (iii) is no, why different expenditure escalators were applied, using supporting evidence; and	
(v) whether, in applying the relevant labour or material escalator, additional contingency factors have been applied and, if so, what	

CPP Proposal Information Compliance Summary	
CPP IM Information Requirements	CPP Proposal Reference
uncertainties they account for and how they were calculated.	
SECTION 9 Information relevant to prices	
<i>5.4.32 Information on proposed new pass-through costs</i>	
A CPP proposal must contain details of any cost not specified in clause 3.1.2(2) that is sought to be specified as a new pass-through cost in accordance with clause 3.1.2(1)(b), including information on-	7.9
<ul style="list-style-type: none"> (a) how the cost is likely to arise; (b) who the cost would be payable to; (c) how the cost would be calculated; (d) any good or service the EDB would receive in exchange; and (e) how the cost meets the criteria specified in clause 3.1.2(3). 	
5.4.33 Information on proposed recoverable costs relating to costs of making CPP application	
Where a CPP applicant seeks specification in the CPP determination of a recoverable cost to which clause 3.1.3(1)(j), 3.1.3(1)(k), or 3.1.3(1)(l) applies, it must provide, in relation to each auditor, verifier or engineer who was engaged to provided an opinion on some aspect of the CPP proposal in accordance with a requirement of this Part-	7.10
<ul style="list-style-type: none"> (a) any document making a public or limited circulation request for proposals to carry out the work; (b) the terms of reference for the work; (c) invoices for services undertaken in respect of the work; and (d) receipts for payment by the CPP applicant. 	

CPP Application Information Compliance Summary

CPP IM Information Requirements

CPP Application Reference

5.1.2 Evidence of consumer consultation

For the purpose of clause 5.1.1(2)(a), in respect of consumer consultation, the specified information is-

- | | |
|---|-----------------|
| (a) a description as to how the requirements of clause 5.5.1 were met; | 2.3 |
| (b) a list of respondents to the consultation required by that clause; | 2.4, Appendix 6 |
| (c) a description of all issues raised by consumers in response to the CPP applicant's intended CPP proposal; | 2.5 |
| (d) a summary of the arguments raised in respect of each issue described in accordance with paragraph (c); and | 2.5 |
| (e) in respect of the issues described in accordance with paragraph (c), an explanation as to whether its CPP proposal accommodates the arguments referred to in (d); and | 2.5 |
| (i) if so, how; and | |
| (ii) if not, why not. | |

5.5.1 Consumer consultation

- | | |
|--|------------------------------|
| (1) By no later than 40 working days prior to submission of the CPP proposal, the CPP applicant must have adequately notified its consumers- | 2.3.1, 2.3.2 |
| (a) that it intends to make a CPP proposal; | 2.3.3, Appendices 1-5 |
| (b) of the expected effect on the revenue and quality of its electricity distribution services were the Commission to determine a CPP entirely in accordance with the intended CPP proposal; | 2.3.3, 2.3.4, Appendices 1-5 |
| (c) of the process for making submissions to the EDB in respect of the intended CPP proposal; | 2.3.4 |
| (d) where and how further information in respect of the intended CPP proposal may be obtained; and | 2.3.3, 2.3.4 |
| (e) of their opportunity to participate in the consultation process required of the Commission by s 53T of the Act after any CPP proposal is received and considered compliant by the Commission. | 2.3.3, 2.3.4 |
| (2) For the purpose of subclause (1)(d), where further information is available in hard copy only, the applicant must have ensured that any further information was readily available for inspection at the stated location. | 2.3.2 |
| (3) For the purpose of subclause (1), the CPP applicant must- | 2.3.2 |
| (a) provide all relevant information; | |

- (b) provide information in a manner that promotes consumer engagement;
- (c) make best endeavours to express information clearly, including by use of plain language and the avoidance of jargon; and
- (d) provide consumers with (or notified them where to obtain) the information through a medium or media appropriate to the natures of the consumer base.

Examples:

- (i) *by placing the information on the EDB's website;*
- (ii) *by providing the information to groups or organisations that represent the consumers' relevant interests;*
- (iii) *by including the information in consumers' or electricity retailers' bills; and/or*
- (iv) *by placing advertisements in local newspapers.*

5.1.3 Verification-related material

(1) For the purpose of clause 5.1.1(2)(a), in respect of verification, the specified information is-

3.1, Appendix 7

- (a) in the case of a CPP proposal seeking only a quality standard variation, nil; and

(b) in the case of any other CPP proposal-

- (i) a verification report; and
- (ii) any information relating to the CPP proposal, other than information required to be included in a CPP proposal by Subpart 4, provided to the verifier by or on behalf of the CPP applicant, pursuant to clause 5.5.2(3);

Examples: instructions as to how to interpret information provided to the verifier; details as to the source of the information; and

- (iii) subject to subclause (2), a certificate signed by the verifier stating that the relevant parts of the CPP proposal were verified and verification report was prepared in accordance with Schedule G.

(2) For the purpose of subclause (1)(b)(iii), the CPP applicant must ensure that the certificate described in subclause (1)(b)(iii) relates to verification of the relevant parts of the CPP proposal as submitted to the Commission.

5.5.2 Verification

(1) A CPP proposal, other than one made by a CPP applicant seeking only a quality standard variation, must be verified by a verifier.

3.1, Appendix 7

(2) The verifier must be engaged in accordance with Schedule F.

(3) The CPP applicant must provide the verifier with-

(a) the materials-

- (i) required by the verifier to verify the CPP proposal in accordance with the terms of his, her or its engagement and Schedule G; and
- (ii) that it intends to submit to the Commission as a CPP proposal;

(b) subject to paragraph (c), the materials referred to in paragraph (a) prior to

the verifier commencing verification in accordance with Schedule G;

(

c) the information required by Schedule D pertaining to projects or programmes meeting paragraph (c) of the definition in Schedule D of identified programme after the verifier has notified the CPP applicant of his, her or its selection of projects or programmes meeting paragraph (c) of the definition of identified programme to the CPP applicant;

(d) any information requested by the verifier pursuant to the verifier's right to ask for such information pursuant to his, her or its deed of engagement, as specified in clause F5(2)(d).

5.1.4 Audit report

(1) For the purpose of clause 5.1.1(2)(a), in respect of audit, the specified information is a report written by an auditor and signed by that auditor (either in an individual's name or that of a firm) in respect of an audit undertaken of the matters specified in clause 5.5.3, stating-

4.1, Appendix 8

(a) the work done by the auditor;

(b) the scope and limitations of the audit;

(c) the existence of any relationships (other than that of auditor) which the auditor has with, or any interests which the auditor has in, the CPP applicant or any of its subsidiaries;

(d) whether the auditor obtained all information and explanations that he or she required to undertake the audit, and, if not-

(i) details of the information and explanations not obtained; and

(ii) any reasons provided by the CPP applicant for its or their nonprovision;

(e) the auditor's opinion of the matters in respect of which the audit was undertaken.

(2) For the avoidance of doubt, an audit report of an audit undertaken other than expressly for the purpose of clause 5.5.3 is an audit report complying with subclause (1) if the report relates to an audit fulfilling the requirements of clause 5.5.3.

(3) The CPP applicant must ensure that the audit report required by this clause relates to the CPP proposal as submitted to the Commission.

(4) For the avoidance of doubt, the audit report required by this clause need not be-

(a) prepared in advance of the verifier undertaking verification of the CPP proposal; nor

(b) provided to the verifier.

(5) If, notwithstanding subclause (4), an audit report prepared in accordance with this clause is provided to the verifier, subclause (3) continues to apply.

5.5.3 Audit

A CPP proposal must be audited by an auditor as to whether or not-

4.1, Appendix 8

(a) as far as appears from an examination of them, proper records to enable the complete and accurate compilation of information required by Subpart 4

have been kept by the CPP applicant;

(b) in the case of actual financial information relating to the current period, that information has been prepared in all material respects in accordance with this determination;

(c) in the case of forecast financial information relating to the next period, that information has been compiled in all material respects in accordance with this determination and the records examined pursuant to paragraph (a); and

(d) in the case of quantitative information provided in spreadsheets, that information is accurately presented.

5.1.5 Certification

(1) For the purpose of clause 5.1.1(2)(a), in respect of certification, the specified information is the certificates recording the certifications specified in clause 5.5.4.

5.1 – 5.3, Appendix 9

(2) For the avoidance of doubt, one physical document may contain more than one of the certifications specified in clause 5.5.4.

5.5.4 Certification

(1) In the case of all information of a quantitative nature, other than forecast information, provided in accordance with this Part, no fewer than 2 directors of the CPP applicant must certify in writing his or her belief that-

5.1-5.3, Appendix 9

(a) the information was derived and is provided in accordance with the relevant requirements; and

(b) it properly represents the results of financial or non-financial operations as the case may be. In the case of all information of a qualitative nature, other than forecast information, provided in accordance with this Part, no fewer than 2 directors of the CPP applicant must certify in writing his or her belief that-

(a) the information is provided in accordance with the relevant requirements; and

(b) it properly represents the events that occurred during the current period.

(3) In the case of all forecast information provided in accordance with this Part, no fewer than 2 directors of the CPP applicant must certify in writing his or her belief that-

(a) the information was derived and is provided in accordance with the relevant requirements; and

(b) the assumptions made are reasonable.

(4) No fewer than 2 directors of the CPP applicant must certify in writing-

(a) that, to the best of his or her knowledge, the verifier was engaged by the CPP applicant in accordance with Schedule F;

(b) that, to the best of his or her knowledge, the CPP applicant provided the verifier with all the information specified in Part 5, including its schedules, relevant to Schedule F;

(c) that, to the best of his or her knowledge, the information referred to in paragraph (b), save that relating to projects or programmes meeting paragraph (c) of the definition in Schedule D of identified programme, was provided to the verifier in advance of the verifier's selection of projects or programmes meeting paragraph (c) of the definition in Schedule D of identified programme, in accordance with clause G3;

(d) a description of any information not provided to the verifier following the verifier's request;

(e) reasons, which, in his or her opinion, justified any non-provision of such information;

(f) that, to the best of his or her knowledge, the-

(i) matters the auditor was engaged to audit included the matters specified in clause 5.5.3; and

(ii) auditor was instructed to report on at least the matters described in clause 5.1.4; and

(g) that the-

(i) audit report provided pursuant to clause 5.1.4;

(ii) verification report; and

(iii) other certifications required by this clause, all relate to the same CPP proposal.

(5) Where-

(a) a director has certified a matter of opinion in accordance with this clause; and

(b) his or her opinion has changed before the Commission's determination of the

CPP in question, that director must notify the Commission as soon as reasonably practicable.

(6) Where-

(a) a director has certified a matter of fact in accordance with this clause; and

(b) before the Commission's determination of the CPP in question he or she-

(i) becomes aware that the fact is untrue; or

(ii) has significant cause to doubt the accuracy of that fact, that director must notify the Commission as soon as reasonably practicable.

(7) For the avoidance of doubt, the certifications required by the different subclauses of this clause may be made by the same or different directors.

Appendix 5

Modifications to Schedule E templates

Modifications to Schedule E Templates

Table	Modification	Explanation
Tables 2, 3, 4, 5	Orion's own expenditure categories rather than the CPP IM ones are included, which is permitted under clause 5.4.31. We have also restated the forecast using the IM categories, consistent with 5.4.31(1)(b)(ii)	We note that the IM categories are not consistent with the way in which the forecasts are prepared. Also since the IMs were determined, the October 2012 ID Determination requires different categories to be applied for the purpose of AMP forecasts, to apply for the first time to the 2013 AMP. Accordingly, we are currently seeking to comply with the new ID requirements. Duplicate templates are not required in order to comply with 5.4.31(1)(b)
Table 2	Table 2 requires capex to be allocated across services. However corporate capex does not support any specific service, together it provides the support infrastructure to deliver all services. We have added a new row in the Table for corporate capex, directly above the total capex row, and independent of the service categories	<p>This mirrors Tables 3(a), (b) and (c) for opex which has corporate opex not assigned to service categories, and included as a separate line item above the total.</p> <p>We believe this is a reasonable adjustment which is consistent with the corporate opex requirements in the IM and the support nature of the capex concerned</p>
Tables 3(a), (b) and (c)	Tables 3 (a) – (c) requires system management and operations opex to be allocated across services categories. However system management and operations opex does not support any specific service, as it provides the support necessary to deliver all services. This is consistent with general management, administration and overheads opex which is not allocated to services in these tables. We have added a new row in the Tables for system management and operations opex, directly next to the general management row, and independent of the service categories	<p>This mirrors the treatment of corporate opex which is not assigned to service categories, and included as a separate line item above the total</p> <p>We believe this is a reasonable adjustment which is consistent with the corporate opex requirements in the IM and the support nature of the office based network management opex concerned</p>
Tables 4 and 5	For each capex and opex project/programme costs by source are required. These are available for actual expenditure to date, but not for most categories of forecast expenditure. We have added a "to be tendered" source for the forecast period	We are unable to assign future network capex and opex to source before it is tendered. Note this excludes corporate costs which are not required to be allocated by source
Table 6 incomplete	Table 6 includes general management, administration and overheads opex. It is not included in tables 4 and 5 as it is not directly attributed against assets. However network management and operations expenditure is also not directly attributed to assets. We have added additional rows in 6 to accommodate this	Required to ensure the full opex programme is included in the schedules. Table 5 and 6 are intended to capture all opex. Table 5 by asset category and Table 6 for overheads opex which is not allocated to network assets (general management, administration and overheads). However system management and operations opex does not fit into either of these tables – ie: it

	category of expenditure	is not undertaken in the field so can't be allocated to network assets and is not included in general management etc.
Table Missing	There is no Table provided for non network capex projects/programmes. We have created a Table 6b for Non system fixed asset capex, similar to Table 6 for Overheads opex (which we have called 6a)	Expenditure data is otherwise incomplete. This is required to ensure our full capex/opex programme is included in the Schedule E templates
Table 7	Table 7 requires information regarding cost escalators. We have not included information pertaining to unit rates and volumes as is anticipated by this Schedule. We have provided information in this Schedule pertaining to yearly escalators and quantum of costs.	Table 7 assumes that escalators are applied to unit costs and that these unit costs are applied to volumes to derive capex and opex costs. We do not propose to escalate costs this way. Real input costs are to be converted to nominal terms by applying escalators (indices) to project costs which are broken down by inputs. This method is explained in Section 9.26
Tables 8 and 9	Tables 8 and 9 address cost allocation. They use opex categories consistent with IM, but we are using slightly different opex categories in accordance with 5.4.31	We have modified Tables 8 and 9 to reflect our expenditure categories
Table 9:	Clause 5.4.29 of the IM refers to Table 9: Cost Allocation B. There is no Table 9 included in Schedule E in CPP IM Determination. It is in the spreadsheet versions of the tables provided which suggests it may have been omitted in error from the Determination itself.	Table 9 included in our CPP proposal consistent with the spreadsheet version of Schedule E we have obtained from the Commission

Appendix 6

Sub-transmission network architecture review



Network Architecture Review: Subtransmission

2012

Table of Contents

1	Executive Summary	3
2	Introduction	4
3	Assumptions.....	4
4	Architecture design.....	7
5	Economics	13
6	Applying the findings.....	18
7	Orion networks 2060	20
8	Sub-transmission switchyard layout options.....	28
9	Modelling tool	38
10	Recommendations	39
11	Appendix A Network topologies	40
12	Appendix B Model Inputs	46
13	Appendix C Bus Coupler Analysis	51
14	Appendix D Switchyard development options	52
15	Appendix E Economic Analysis of bus configurations	59
16	Appendix F Bus Protection	60
17	Appendix G Comparison of Ring Layout Options 1A & 1B for Network Faults	62

1 Executive Summary

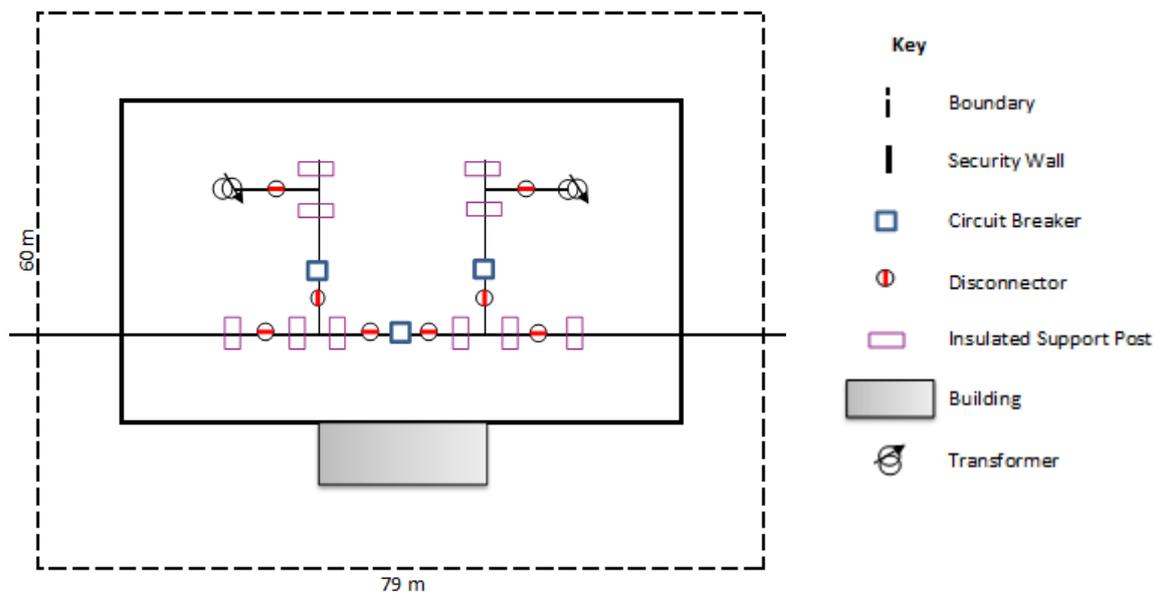
In view of the unprecedented investment by Orion in new and replacement assets over the next 50 years, due to

- earthquake damaged assets
- changes in load due to post-earthquake reconstruction and relocation
- projected load growth in the western urban regions, independent of earthquake effects

it is appropriate to review the network design principles. This report is the first step in that process and examines subtransmission topologies.

It is recommended that future extensions to the Orion subtransmission 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. 11 kV tie capacity between adjacent zone substations should allow a substation's complete load to be carried by two neighbouring substations.

The preferred switchyard layout for a site with two circuits and two transformers is shown below:



This ring bus design provides superior fault performance and facilitates additional circuits being added in the future.

Collecting data on circuit breaker failure rates and bus faults will enable the model to be enhanced for future architecture reviews. Developing functionality in Power On to calculate kWhrs lost during faults will enable the cost of outages to our customers to be more accurately modelled than is currently possible using the SAIDI and SAIFI indices.

2 Introduction

In 2010 Orion was entering a phase of increased investment in the urban upper network, with up to 10 zone substations in planning and the acquisition of Transpower spur assets in prospect. The earthquakes of 2010-11 resulted in significant damage to subtransmission assets plus load shifts due to abandonment of some areas and relocation of residential and commercial customers. The company now faces a period of unprecedented construction, with decisions which will shape the network for several decades to come.

It is therefore an appropriate time to review the design principles which determine the architecture of our network at all voltages. The first stage of this architecture review covers the 66 kV/33 kV subtransmission network.

The drivers for the new assets are:

- to provide capacity for projected load growth (particularly in the urban north, north-west, west, and south-west)
- to improve security of supply for some of the 10 zone substations¹ which are currently on single 66 kV feeds or a pair of radial cables/lines in a common trench/tower
- to develop resilience to major events, and reduce exposure to serious outages at Islington, Addington or Bromley by increasing cross-GXP transfer capability

3 Assumptions

In a comprehensive review a balance must be struck between starting from an empty page and challenging all assumptions, and achieving a pragmatic result in a reasonable timeframe. The following assumptions, resulting from other planning exercises, are made:

1. Orion urban load is forecast to be nearly 900 MW in 2060²
2. Bromley 66 kV, Islington 66 kV and Islington 33 kV will remain the only urban GXPs, with firm (N-1) capacities of 420 MW³, 540 MW and 106 MW respectively
3. New 220/66 kV GXPs will be required to the southwest of Christchurch to provide for growth in the Selwyn district and to support Islington contingencies
4. the optimum zone substation capacities are 40 MW⁴ (66/11 kV) and 23 MW (33/11 kV).
5. subtransmission at 33 kV does not provide sufficient capacity to economically allow full load transfer between GXPs, so if these links are deemed necessary no expansion of the 33 kV network will take place⁵ and all new investment will be at 66 kV

¹ Hoon Hay, Milton, Middleton, Hawthornden, Ilam, Fendalton, McFaddens, Barnett Park, Dallington and Rawhiti.

² There is significant uncertainty in this forecast and the chosen architecture must allow for a staged approach as load growth eventuates.

³ The increase in Bromley capacity from 210 MW in 2013 to 420 MW will take place when load growth requires.

⁴ 40 MW is close to the limit of our standard 11 kV switchgear. Also, it is more cost-effective to add a new site on an interconnected network than to deal with the congestion of 11 kV feeder cables installed around a substation of more than 40 MW.

⁵ New substations on the existing 33 kV cable network may be appropriate where back up can be provided by neighbouring and interconnected 66kV substations e.g. the proposed Main South Road site.

6. where N-1 subtransmission security applies, an N-2 event should not result in the loss of more than one zone substation. If a substation is lost for any reason, the neighboring substations must be able to pick up the lost load on the 11 kV network. This implies there must be enough redundant capacity in the 66 kV network to feed the extra load to those sites
7. GXP's cannot be permanently operated in parallel. Parallel operation opens up operational issues with Transpower and the electricity market, and the cost to rectify these constraints is prohibitive
8. The review is mainly focused on the urban network and all costs assume underground 66 kV installation except where noted

Assumptions 1 and 4 imply the need for 22 40 MW urban zone substations. Given that the Islington 33 kV interconnectors are early in their life cycle and there is substantial sunk cost in Orion's urban 33 kV assets, there is no proposal for an early withdrawal from 33 kV. Also due to their location some 66 kV substations are unlikely to reach 40 MW load. This complicates the number of sites required for the model. As a starting point the high-level models (see section 4.2) are based on a scheme of 20 66 kV zone substations, with 10 on each GXP (including a zone substation at or very near the GXP site).

Assumption 6 has a major effect on network design. A subtransmission branch which provides N-1 security can be vulnerable to the loss of all zone substations in an N-2 event (see Figure1). If we assume that for N-1 systems an N-2 event should be recovered in switching time rather than repair time, then assumption 6 means only one zone sub will require 11kV support in an N-2 66 kV event. This limits the amount of switching to avoid long outages, and limits the redundant capacity required in the adjacent zone substations, and the 11kV ties needed between them.



Figure 1

However, Assumption 6 requires an N-1 system to be “almost N-2” and will be more expensive than an N-1 design which allows potential loss of all load in an N-2 event, with restoration in repair time. Simple probabilistic analysis shows that this extra cost is justified.

Standard 66 kV XLPE conductor sizes are employed in the design options (see Table 1). The listed capacities are best-case and may require de-rating after installation, depending on ground conditions, ducting, cable congestion etc.

To manage inventory costs it is likely that only a subset of these cable sizes will be chosen for use, but to make the best decision about which sizes are suitable all were treated as available in the various design options.

It is worth noting that the smallest cable (300Cu) has a capacity of around 60 MVA, which is 50% more than the standard zone substation capacity. This means that a substation may be carried by two of its neighbours without increasing the minimum cable cost (provided 11 kV ties are adequate).

The cable cost per MVA decreases as cable size increases, so as a general rule fewer larger cables are cheaper than more smaller cables, and also require less switchgear. However fewer larger cables means that more load is at risk from planned and unplanned outages and providing security against this can be expensive.

size	lay	MVA	\$/m installed
300Cu	∴	58	728
	...	61	
630Cu	∴	87	887
	...	95	
800Cu	∴	97	962
	...	106	
1000Cu	∴	107	1088
	...	119	
1200Cu	∴	120	1167
	...	137	
1600Cu	∴	141	1354
	...	166	

Table 1: 66kV cable sizes

Costs are the best available at December 2011 and include installation and jointing. Termination costs are included in the installed switchgear or transformer cost.

Installation costs for 2 circuits together save \$60/m.

Other cost data may be found in Appendix B Model Inputs.

4 Architecture design

4.1 Security of supply

The optimum network topology depends on the relative costs and benefits of:

- security levels (N vs. N-1 vs. N-2)
- interrupted vs. non- interrupted supply after contingencies
- radial vs. ring topologies (plus hybrids)
- provision for HILP⁶ events (in particular, subtransmission links between GXPs)

Orion's Security Standard Review in 2007 addressed load thresholds and restoration times for zone substation security levels. It is not proposed to review the methodology of this study but updated VOLL values will be taken into account. HILP events were not explicitly covered, but post-quake learnings and the likelihood of continuing seismic activity now bring this into focus, despite the difficulty in quantising the risks.

The occurrence of a "one in X year" event should not be a cause for complacency (the common fallacy being that the "law of averages" means another disaster is unlikely to occur for a long time). The earthquakes triggered many aftershock sequences to the surprise of experts, who now warn of elevated risk for the indefinite future, decades of heightened seismic activity and significant probability of further >7.0 tremors. The success of the 1980s-1990s substation civil reinforcement programme repaid the investment many times over. Given the increasing dependence on electricity of modern society, and the distress of customers left without power for days in February 2011, it would seem clear that Orion's responsibility to shareholders and customers alike is to provide a network with increased resilience to major events, provided the HILP investment premium is appropriate.

4.2 Generic topologies

Future development takes place on an existing asset base of nearly \$1b, with a complex history of separate Electricity Board architectures and different eras of design philosophy. A theoretical green-fields approach to optimal network design may give a useful steer on future expansion but in the end, must also make the best use of existing assets for the remainder of their life cycle.

Estimating the cost of various options is difficult, as they depend on actual cable routes, switchgear arrangements etc. and to comprehensively cost out all the permutations would take years of work. So, very high-level generic models were used to compare the approximate costs of the different approaches, allowing the elimination of some, and the selection of the most promising candidates for more detailed analysis.

Six architectures were considered (Table 2).

Since these have many possible variants, the initial comparison was done on generic high-level models (see Appendix A) consisting of 2 GXPs with 9 zone substations each at equal distances from the GXP. Once the more promising schemes were identified, these were laid out on a map of Christchurch to obtain more realistic cable route lengths.

⁶ High Impact Low Probability events, also known as MOCHED (*Major Outages Causing Huge Economic Damage*). While this could cover a variety of situations involving the loss of multiple zone substations, the worst-case scenario is typically the loss of an entire GXP. Since the number of affected customers is very large and the repair times for interconnecting transformers very long, a high value is placed on cross-GXP subtransmission links.

Architecture			66 kV contingency result	Load restoration
1a	N radial, no 11 kV ties	no GXP links	restore 66 kV in repair time for single fault	restore load in 66 kV repair time
1b	N radial, 11 kV ties	no GXP links	restore 66 kV in repair time for single fault	restore load by switching 11 kV (max. 1 sub) for single 66 kV fault
2	N-1 radial, 11 kV ties	no GXP links	no break in 66 kV for single fault	restore load by switching 11 kV (max. 1 sub) for 2 66 kV faults
3	N-1 rings, 11 kV ties	no GXP links	no break in 66 kV for single fault	restore load by switching 11 kV (max. 1 sub) for 2 66 kV faults
4	N-1 radial, 11 kV ties	GXP links	restore 66 kV in switching time for single fault (possibly fast automated switching)	restore load by switching 11 kV (max. 1 sub) for 2 66 kV faults
5	N-1 rings, 11 kV ties	GXP links	no break in 66 kV for single fault	restore load by switching 11 kV (max. 1 sub) for 2 66 kV faults
6	N-2 rings	GXP links	no break in 66 kV for 1 or 2 faults	restore load by switching 11 kV (max. 1 sub) for 3 66 kV faults

Table 2

Architecture 1 has zone substations with one 66 kV cable and one transformer. Variant 1a has 40 MVA transformers which provide no redundancy or spare capacity, so 11 kV ties between substations are not needed – outages will be restored in repair time.

There are two ways to introduce redundant capacity into such a network – increase the number of substations so that each 40 MW transformer supplies a normal load of 26MW, or increasing the transformer size to 60 MW for a normal load of 40 MW. Both these schemes allow a zone substation to be supported over 11kV by two neighbours.

The first option violates Assumption 4 regarding optimum 66/11 kV substation capacity. The second option is certainly cheaper and given that the smallest cable is ~60 MW is a natural fit. This is variant 1b.

Architectures 2-5 have zone substations with 2x40 MVA transformers providing redundancy, and also spare capacity to support neighbouring substations via 11 kV ties.

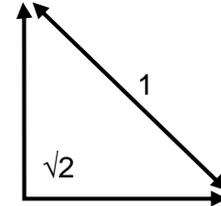
Architecture 6 has 2 variants – 6a has N-2 cable security but 2 transformers per site. 6b has 3 transformers per site providing full N-2 security for both cable and transformer outages.

11 kV ties (which provide interrupted N-2 security in an N-1 subtransmission scheme) may be considered unnecessary in Architecture 6, which provides N-2 security at 66 kV. Analysis was done for 6a and 6b with and without 11 kV ties.

4.3 Topologies specific to Christchurch

Once the most economic networks in each category were identified in a generic analysis with unit link lengths, they were laid out on a map of Christchurch to provide a more realistic estimate of cable lengths. Identifying and comparing actual cable routes was considered too time-consuming at this stage, so direct distances were measured and a scaling factor applied to allow for the extra length of a practical installation.

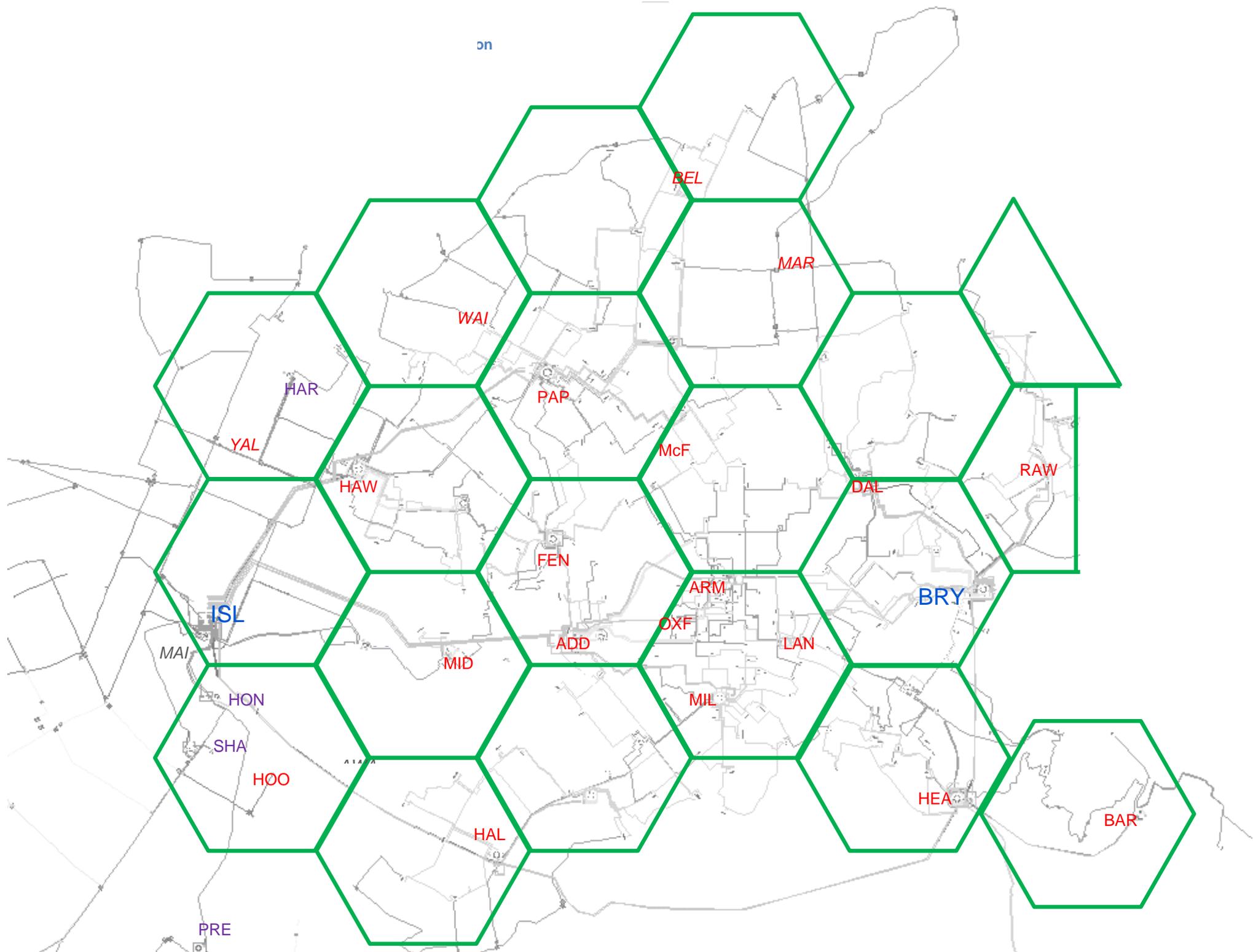
A factor of 1.4 was chosen (from the worst-case extra length required to join 2 points by orthogonal straight links. This factor can be varied for sensitivity analysis.



Historically the CBD was an area of high load concentration but will probably be less so after earthquake reconstruction. As a first approximation the urban area was divided into 20 cells of equal density (Figure 2 overleaf). Existing and planned⁷ zone substations are shown for reference (*existing 66kV red, planned 66kV red italic, existing 33kV purple, planned 33kV purple italic*).

Figure 3 shows an example of a network laid out to estimate link lengths. Layouts were optimised iteratively by measurement, trial and error.

⁷ As in the 2012 AMP



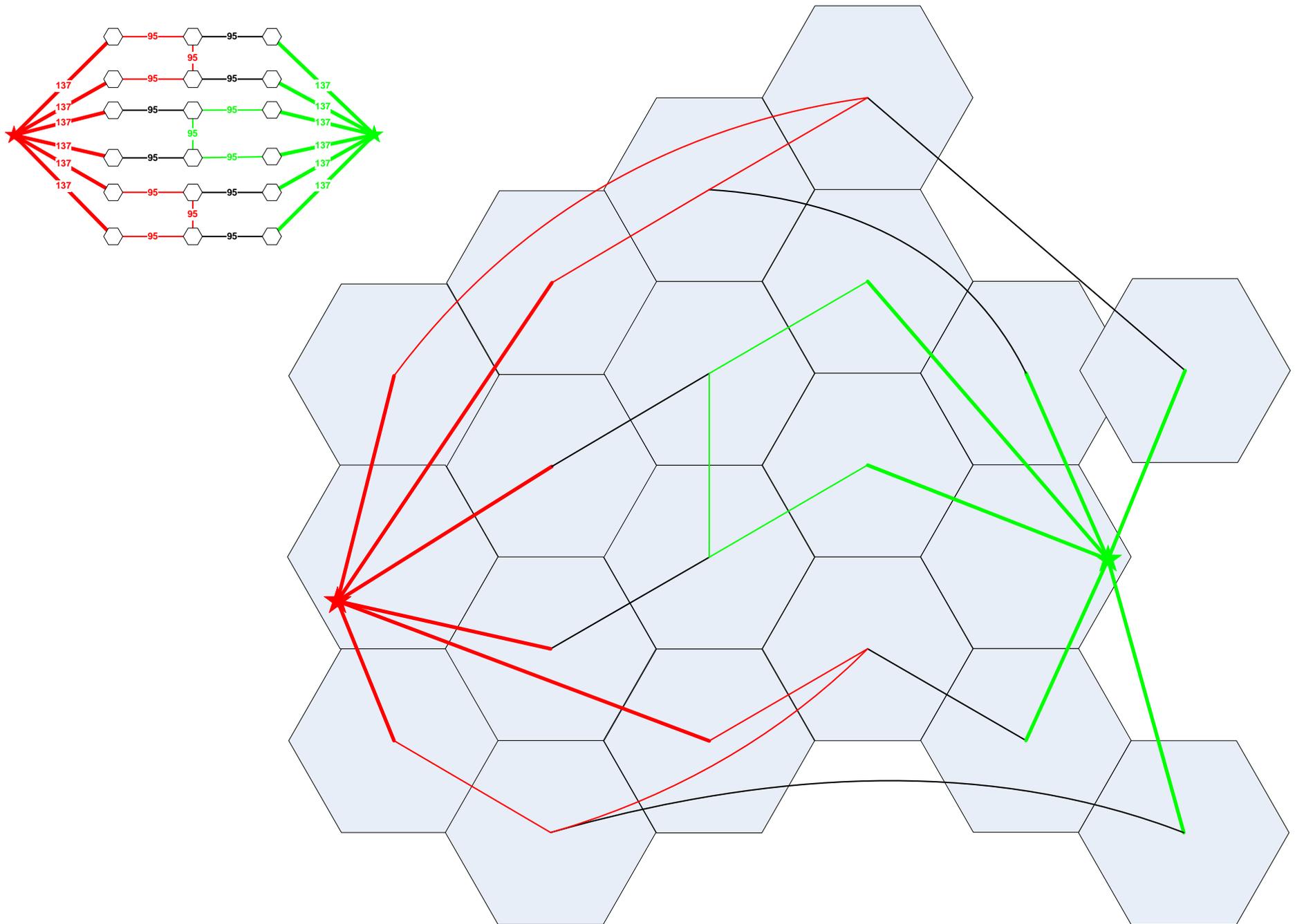


Figure 3: example of network layout

4.4 Comparison of topologies

The high-level estimated cost for building a 20-substation 66 kV subtransmission network according to the various security schemes is shown in Table 3. The zone substations at the GXP's are assumed to be on a 2-cable radial feed.

Low voltage and 11 kV assets are not included except for the incremental cost of providing tie support between zone substations⁸. GXP assets are not considered except for one bay per cable. A fixed cost of \$1m per 66 kV switchyard is included.

Arch.	Figure	cable cost \$m	breaker cost \$m	switchyard cost \$m	transformer cost \$m	11kV ties cost \$m	total \$m
N radial, 1x40MVA transformer with no CB, no GXP links, no 11kV ties							
1a	A1	112	7	0	31	0	150
N radial, 1x60MVA transformer with no CB, no GXP links, 11kV ties							
1b	A1	112	7	0	36	6	161
N-1 radial, 2x40 transformers with no CB, no GXP links, no 11kV ties							
2	A2	213	14	0	62	0	289
N-1 radial, 2x40 transformers with no CB, no GXP links, 11kV ties							
2	A2	213	14	0	62	6	295
N-1 rings, 2x40 transformers, no GXP links, 11kV ties							
3	A3c	173	30	18	62	6	288
N-1 radial, 2x40 transformers, GXP links, 11kV ties							
4	A4	198	25	18	62	6	309
N-1 rings, 2x40 transformers, GXP links, 11kV ties							
5	A5b	192	27	18	62	6	305
N-2 rings, 2x40 transformers, GXP links							
6a	A6	216	34	18	62	0/6	330/336
N-2 rings, 3x40 transformers, GXP links							
6b	A6	216	41	18	93	0/6	368/374

Table 3

Key findings:

- The cost of laying cable is the dominant component of the network value
- The premium for N-1 subtransmission over N is around \$140m (93% of the N cost) or \$6.9m per zone substation
- The premium for N-2 subtransmission over N-1 with GXP ties is around \$31m (10% of the N-1 cost) or \$1.6m per zone substation
- The premium for full N-2 security (3 cables, 3 transformers per substation) over N-2 subtransmission (3 cables, 2 transformers) is around \$38m (12%) or \$1.9m per zone substation
- The premium for a ringed network with full inter-GXP connection over a ringed network with no connection is around \$16m (6% of the no connection cost) or \$0.8m per zone substation

Note that some subtransmission rings and limited cross-GXP ties already exist in Orion's network, so the purely radial architectures or those with no GXP ties are not a practical option. Nonetheless this study assists in the decision as to whether to reinforce these ties in the future.

⁸ The cost per substation was identified in the Orion Security of Supply Standard Review of 2005 as \$292k (inflation adjusted to 2012).

5 Economics

5.1 Value of Lost Load (VOLL) and Value of Interruption (VOI)

An official VOLL figure was last published by the Electricity Commission in 2004 as \$20,000/MWh (Electricity Industry Participation Code). When this is CPI-adjusted to 2012 it becomes \$24,967.

A VOLL review⁹ was initiated in 2008 and as part of this process the Electricity Authority commissioned a set of customer surveys in 2011. The collated data from these surveys has been released¹⁰ but the industry consultation stage is not scheduled to begin until mid-2012, so officially published values are not available at the time of writing. Producing a useful VOLL figure (or better, a matrix of values for different customer types and seasons etc.) from this data is problematic.

The VOLL used in the Orion 2012 AMP is \$16,260/MWhr. We also apply a Value of Interruption (VOI) component of \$6970/MW, so the total VOLL for the first hour of interruption is $\$16,260 + \$6,970 = \$23,230/\text{MW}$ which is in good agreement with the adjusted EC figure. VOLL decreases after the first hour to \$16,260/MWhr. Until the EA publish their findings we will continue to use these values.

5.2 66 kV economics (ideal architectures)

The costs of building the various architectures are laid out in Table 4. The benefits have been identified as follows.

VOLL

This is the expected average cost of unserved load due to subtransmission contingencies which are predictable (in a probabilistic sense), based on the frequency and consequence of various failure modes. Transmission and GXP outages which are rare and unpredictable in nature are addressed separately from the VOLL analysis.

Loss effects

The different architectures have different cable lengths and sizes, and so the power losses will be different for each and were modeled in powerflow software. Three different cost effects of losses were considered.

Losses at peak load mean extra power is required to be supplied by generators through the grid. The long-run marginal cost (LRMC) of generation capacity at network peak loading times is set by the cost of peaking generators and is taken as \$125/kW. This is a cost to New Zealand in general, rather than to Orion; nonetheless, any investment made by Orion which reduces losses will provide a regulated return, and is a valid component of the analysis.

The Transpower grid interconnection charges payable by Orion are set by the Orion peak load contribution to the upper South Island peak load and whilst the Transpower grid interconnection charge may not reflect the immediate short-run marginal cost (SRMC) of

⁹ <G:\Network Development\Network planning\Electricity Commission or Authority\VOLL survey\Value-of-use-final-report 2008.pdf>

¹⁰ <G:\Network Development\Network planning\Electricity Commission or Authority\VOLL survey\100727 Electricity commission VOLL surveys.pdf>

extra upper South Island capacity, it is assumed to be a reasonable proxy of the LRMC. The 2012-13 grid interconnection charges are \$91/kW.

There is also the annual cost of energy wasted in losses. This is an aggregate of energy losses over all load levels over the year. The commonly used formula for estimating the loss load factor for average losses is $LLF = 0.3*LF + (0.7*LF)^2$, where Orion's load factor LF is taken as 0.6. The wholesale cost of energy in 2012 is around \$90/MWhr.

Both the wholesale cost of energy and the grid interconnection charges are expected to rise faster than general inflation for the foreseeable future.

Value of network capacitance

The Transmission Pricing Advisory Group has recommended the introduction of a charge on reactive power drawn from the grid. This will place a value on the capacitance embedded in networks, which offsets the investment required in power factor correction and voltage support equipment on the grid. The different architectures comprise different levels of capacitance in the installed 66kV cable.

The extra cable involved in 11kV tie support is also significant. The review of the 11kV architecture has not been undertaken at the time of writing this report, so the amount of extra cable required for ties has been taken from the 2005 supply security analysis.

The suggested charge¹¹ is \$4-5/kVAr. A figure of \$4.50 was used in the following table.

There is significant value in cable capacitance to Orion as well, for reducing reactive power flows and maximizing the real power able to be delivered by the cable network. This value has not been quantized but will favour interconnected architectures.

Table 4 summarises the costs (network construction, VOLL, and loss effects) and offsetting benefits (value of network capacitance) for the various architectures.

Notes:

The rate of return normally used to find the annual cost of an Orion investment is about 14%. The operational cost of the upper network is considerably less than that of the 11/0.4kV assets, so a reduced figure of 11% was used to derive the annualised network construction cost.

The VOLL for the N-1 radial architectures without GXP links (Arch. 2) is based on cable fault probabilities assuming independent cable routes. Since the pair of cables to each zone substation are laid together in a shared trench, this does not take into account the common-mode risk (for events such as excavation accidents or earthquake damage happening to both cables). This added risk is significant and is borne out by double cable outages for Orion in recent years. Because the total cost of N-1 ringed architectures without GXP links (Arch. 3) is less than that of Arch. 2 even without taking common-mode risk onto account, no attempt was made to include it and it is taken that for N-1 networks without GXP links, radial connections are inferior to rings.

¹¹ Table 2 of Draft TPAG paper – Static Reactive Compensation section on <http://www.ea.govt.nz/our-work/advisory-working-groups/tpag/22Aug11/>

Arch.	Figure	network cost \$m	annualised cost \$m	VOLL* \$k p.a.	loss effects \$k p.a.	reduction in Var charges (66kV) \$k p.a.	reduction in Var charges (11kV**) \$k p.a.	total cost pa \$m
N radial, 1x40MVA transformer with no CB, no GXP links, no 11kV ties								
1a	A1	150	16.5	294,364	3,653	-193	0	314.3
N radial, 1x60MVA transformer with no CB, no GXP links, 11kV ties								
1b	A1	161	17.7	5893	3,653	-193	-2,392	24.6
N-1 radial, 2x40 transformers with no CB, no GXP links, no 11kV ties								
2	A2	289	31.8	759	2,371	-385	0	34.5
N-1 radial, 2x40 transformers with no CB, no GXP links, 11kV ties								
2	A2	295	32.5	9.90	2,371	-385	-2,392	32.1
N-1 rings, 2x40 transformers, no GXP links, 11kV ties								
3	A3c	288	31.7	0.343	2,615	-314	-2,392	31.6
N-1 radial, 2x40 transformers, GXP links, 11kV ties								
4	A4	309	33.9	0.287	2,228	-376	-2,392	33.4
N-1 rings, 2x40 transformers, GXP links, 11kV ties								
5	A5b	305	33.5	0.122	2,425	-366	-2,392	33.2
N-2 rings, 2x40 transformers, GXP links, no 11kV ties								
6a	A6	330	36.3	9.88	2,655	-395	0	38.6
N-2 rings, 2x40 transformers, GXP links, 11kV ties								
6a	A6	336	36.9	0.0108	2,655	-395	-2,392	36.8
N-2 rings, 3x40 transformers, GXP links, no 11kV ties								
6b	A6	368	40.5	0.677	2,655	-395	0	42.8
N-2 rings, 3x40 transformers, GXP links, 11kV ties								
6b	A6	374	41.1	0.00273	2,655	-395	-2,392	41.0

Table 4

*66 kV contingencies only

**additional capacitance due to 11 kV ties

Notes continued

The VOLL for architectures 3-6 assume the provision of rapid automatic switching following contingencies, to close open points and/or relieve temporary cable overload. The VOLL for these topologies is overstated as equal cable lengths were assumed in the outage calculations¹². In parallel systems equal lengths provide higher outage rates than unequal lengths (which occur in the actual network model). Due to the relative insignificance of VOLL compared to loss effects in these architectures, a correction has not been made for this.

Architecture 1b requires 11 kV switching to cover all planned and unplanned outages. This is an opex burden which would increase the total annual network cost by an amount which is difficult to specify.

Due to the requirement that no more than one zone substation is at risk from a double fault, the N-1 radial network with GXP ties (Figure A4) is almost a ringed network and is similar in overall cost.

¹² To consider different cable lengths for each link would make the probability analysis prohibitively complex, without the use of reliability modelling software.

Key findings:

- The N radial network without 11 kV ties (1a) is totally uneconomic
- N-1 radial networks have the same or higher total cost than N-1 ringed networks (given the requirement that no more than one zone substation is at risk from two concurrent faults)
- In each case it is economic to include 11 kV tie support between zone substations
- The N-2 network with 3 transformers per site is uneconomic

After eliminating the least promising candidates, we have:

Arch.	Figure	total cost \$m p.a.	additional cost over Arch. 1b \$m p.a.
N radial, 1x60MVA transformer with no CB, no GXP links, 11kV ties			
1b	A1	25	
N-1 rings, 2x40 transformers, no GXP links, 11kV ties			
3	A3c	32	7.0
N-1 radial, 2x40 transformers, GXP links, 11kV ties			
4	A4	33	8.8
N-1 rings, 2x40 transformers, GXP links, 11kV ties			
5	A5b	33	8.6
N-2 rings, 2x40 transformers, GXP links, 11kV ties			
6a	A6	37	12.2

Table 5

Bearing in mind the additional opex for 1b as discussed above which will increase its overall cost and reduce the cost premium for the interconnected models, the following conclusions may be drawn:

- Architecture 3 has significantly more total cost than Architecture 1, for no extra benefit.
- Architecture 6 has significantly more total cost than Architecture 5, for no extra benefit.
- The economics of architectures 4 and 5 depend on the value of cross-GXP links.

5.3 HILP economics (ideal architectures)

The probabilistic analysis used for the average expected cost of 66 kV subtransmission outages cannot be readily applied to HILP events on the transmission grid or GXP, due to speculative probability of occurrence and the high concentration of load through key sites. This results in significant uncertainty around common-mode risks for multiple assets with large load at risk and long repair times.

Rather than attempt to estimate outage frequencies and durations, it may be more useful to examine what type of event will justify the added cost of building cross-GXP ties (\$8.6m p.a.).

The Islington GXP is located close to Christchurch International Airport Limited (CIAL), and in the Waimakariri river flood plain. Events such as major fires/explosions, floods, tsunamis,

earthquakes, plane crashes or sabotage could result in complete or partial destruction of a GXP site, with repair times on the scale of months.

In the Islington Disaster Recovery Plan¹³ prepared for Transpower by Tesla LineTech Mitton Consulting, it is suggested that following a catastrophe at Islington it would take 24 hours to restore 220 kV supply to Bromley and any other 220 kV GXPs in the region, and 3 months to restore Islington supply through emergency measures¹⁴.

For the generic network of 800 MW supplied from two 400 MW GXPs the following VOLL values apply to the total loss of either GXP, with no 66 kV supporting link capacity. A load factor of 0.6 is applied.

- One 3-day outage (or three 1-day outages) have a VOLL of \$283m. If this occurred once in 33 years, this represents an average annual VOLL of \$8.6m
- One 7-day outage has a VOLL of \$657m. If this occurred once in 76 years, this represents an average annual VOLL of \$8.6m
- One 3-month outage has a VOLL of \$8.5b. If this occurred once in 1000 years, this represents an average annual VOLL of \$8.5m

The only HILP event considered above is a catastrophe at a GXP site. A highly interconnected network with 11kV ties and cross-GXP links provides resilience to many foreseeable and unforeseeable situations, such as the recent earthquakes which did not cause much damage to GXPs but to many other parts of the network. VOLL is improved by reducing switching times and providing multiple options for re-routing supply.

As interconnection charges and the wholesale cost of energy rise, Architecture 1 becomes relatively more expensive compared to the other options. Given the remarks in section 4.1, and the fact that the \$8.6m premium for GXP ties is overstated due to the additional opex costs (quantify) of Architecture 1, it is appropriate to build a network with resilience against HILP events.

We can conclude that from a greenfields perspective, a ringed N-1 architecture with cross-GXP links is preferred.

¹³ Document MEL-R452 Rev 01, June 2009

¹⁴ Some load could be restored earlier than this due to existing cross-GXP ties, but at this point we are considering the value of having no ties vs. full tie capacity.

6 Applying the findings

6.1 Orion 2012-2060

Sections 1-5 of this report considered the best greenfields architectures; Sections 6-7 consider the best way to incrementally build on the existing Orion network, informed by the findings above. The following points are important.

6.2 33 kV network

The Islington 33 kV GXP is in early lifecycle and will be retained for at least 50 years. But the Springston 33 kV GXP is likely to be removed in the next 20 years with that network converted to 66 kV. This will leave ISL33 islanded; support must be at 11 kV from 66 kV substations. Some 33 kV zone substations will need to convert to 66 kV to manage this - probably Moffet and Shands due to their proximity to 66 kV supply.

6.3 Number of zone substations

Orion already has 22 urban substations, and growth in the north means another 3-4 will be required. Given that the 33 kV stations are 23 MVA capacity and the location of some 66 kV stations means they will probably never exceed 23 MVA, when the urban demand reaches ~900MW all 26 sites should be close to nominal capacity.

New 220/66 kV GXPs at Springston and/or West Melton are a preferred option over increasing load on Islington, and will cover growth in Selwyn District to the southwest of the city. The new GXP(s) will support Islington in a 66 kV outage and allow Bromley GXP to remain at no more than 420 MVA firm capacity.

6.4 Existing network

Orion's existing and planned urban substations (as in the 2012 AMP) are shown in Figure 4.

There are 10 substations on N-1 radial feeds. Limited cross-GXP ties already exist in the Halswell-Heathcote tower lines and the Lancaster-Armagh cable.

There are two other likely routes for GXP links – by connecting McFaddens to Dallington, and from Hawthornden to Rawhiti via the future Waimakariri and Marshland sites.

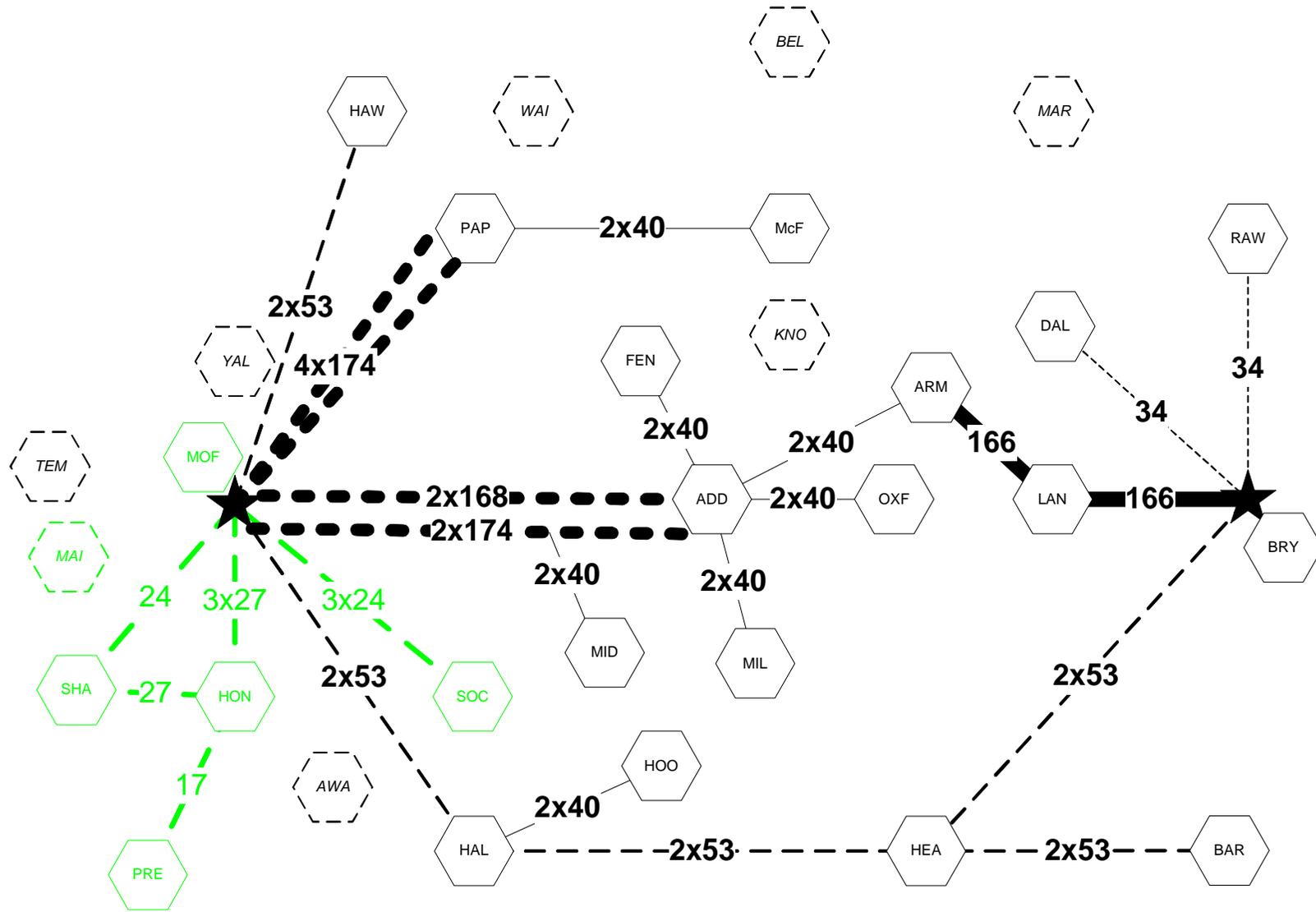
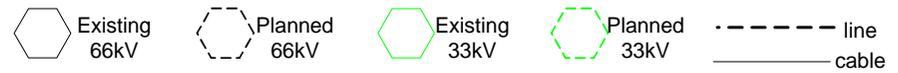


Figure 4: existing and planned urban substations (2011)



It has been established that ringed networks are more advantageous than radial networks, and although the Orion urban network is largely N-1 radial at present the following work assumes that further construction will incorporate closed rings where feasible.

With regard to GXP ties, two approaches are considered – building towards full tie capacity (section 7.1), and not adding to the existing ties (section 7.2). Existing ties are provided by the 2x40MVA Addington-Armagh cables and the 2x53MVA Halswell-Heathcote lines. Once GXP(s) in the Selwyn district are installed, the Islington-Springston and Islington-Weedons circuits will provide further GXP support for Islington.

7 Orion networks 2060

7.1 N-1 ringed network with full GXP ties

The existing layout does not match any of the idealised architectures discussed in sections 4 and 5 very well.

Given the current and planned site locations, and their natural grouping into 4 cross-GXP branches, the N-1 ringed arrangement in Figure 5 is a good fit and can be adapted to existing plans. It did not initially attract interest in the generic high-level study as it is not symmetrical (more load on Islington than Bromley, and Bromley cannot cover all of Islington load). However this suits the actual GXP capacities and the fact that Islington outages will be partially supported by new GXPs to the west.

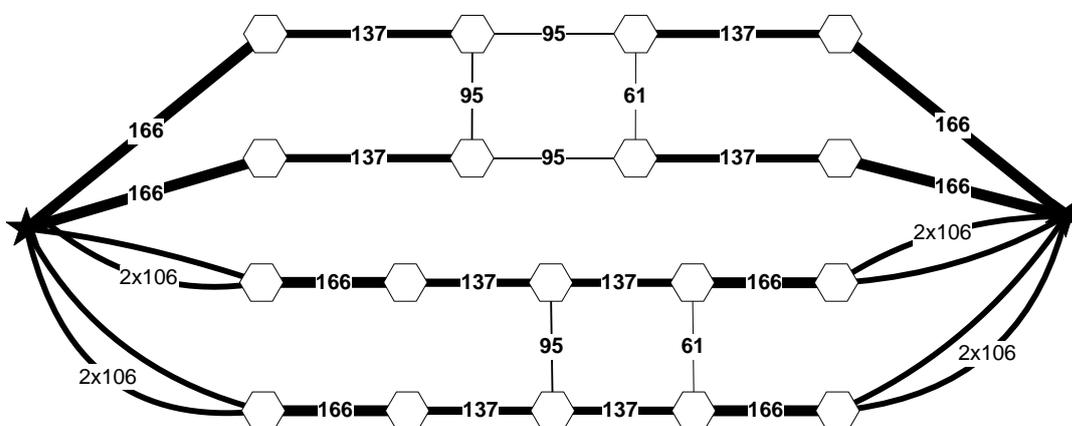


Figure 5

The network in Figure 5 is a more expensive greenfields option than the optimum N-1 ring plan in Figure A5b (see Table 6). However the fact that the 8x174 MW Islington-Papanui and Islington-Addington tower lines, and the Halswell-Heathcote tower lines, are already in service changes the economics. The existing 1600Cu Bromley-Lancaster cable also matches the requirements.

Arch.	Figure	cable cost \$m	breaker cost \$m	switchyard cost \$m	transformer cost \$m	11kV ties cost \$m	total \$m
N-1 radial, 2x40 transformers, GXP links, 11kV ties							
4	A4	198	25	18	62	6	309
N-1 rings, 2x40 transformers, GXP links, 11kV ties							
5	A5b	192	27	18	62	6	305
	5	246	30	18	62	6	361
N-2 rings, 2x40 transformers, GXP links, no 11kV ties							
6a	A6	216	34	18	62	6	336

Table 6

The diagrams on the next pages show the proposed network with full GXP links around 2060, assuming all zone substations are at capacity or their expected maximum load. All urban stations are no-break N-1. Some rural stations are switched N-1 or N.

Figure 7 shows existing and planned assets, Figure 8 has the normal operating state, Figure 9 shows the loss of Bromley GXP, and Figure 10 shows the loss of Islington 66 kV GXP. Red rings indicate the links at or near capacity.

The main point to emerge from this design apart from cable sizing, is that the Armagh-McFaddens cable in the 2012 AMP (which provides for Bromley a ring with 3 feeders and an open branch, Figure 6 left) is less useful than a Milton-Hoon Hay link (which provides for two 2-feeder rings, Figure 6 right).

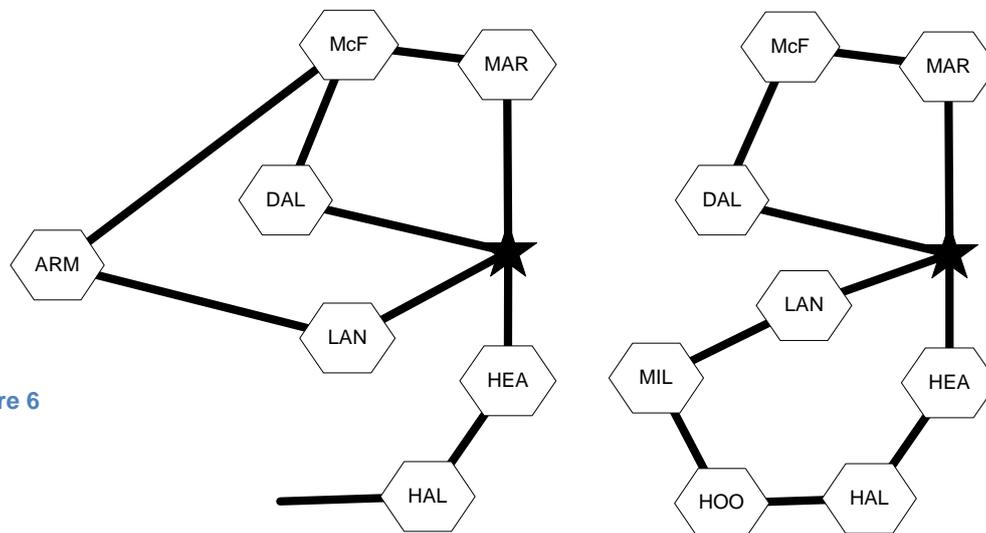


Figure 6

Figure 1: network with full GXP links

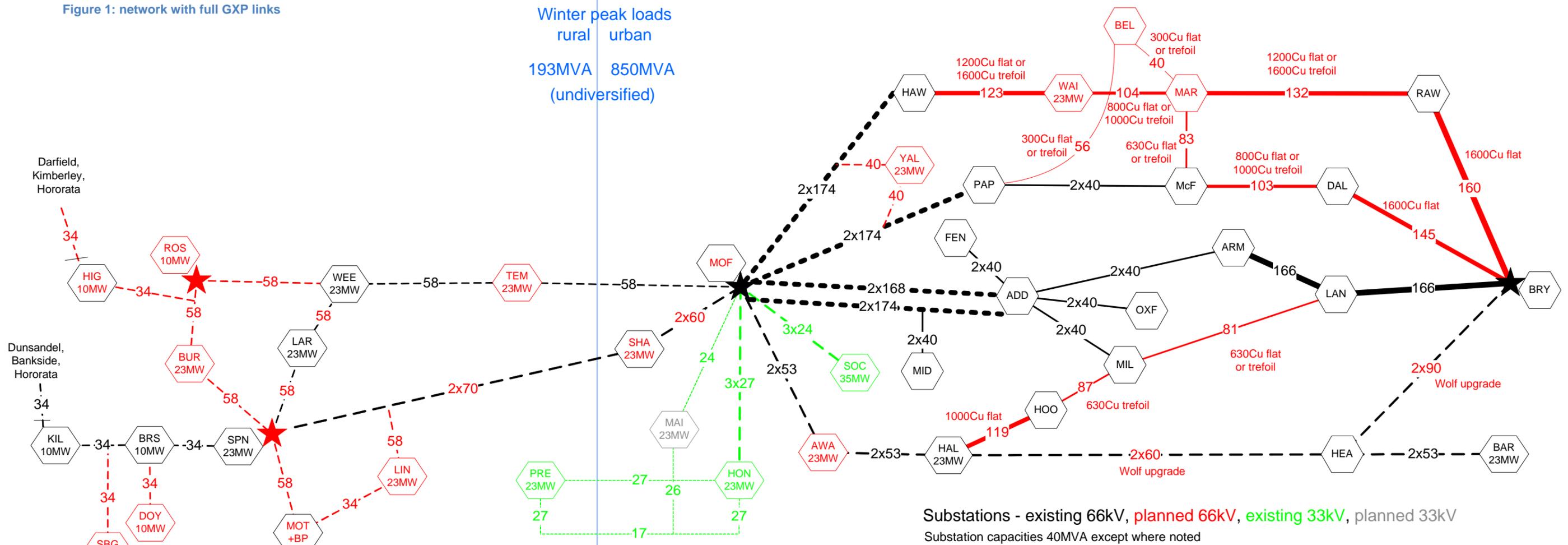
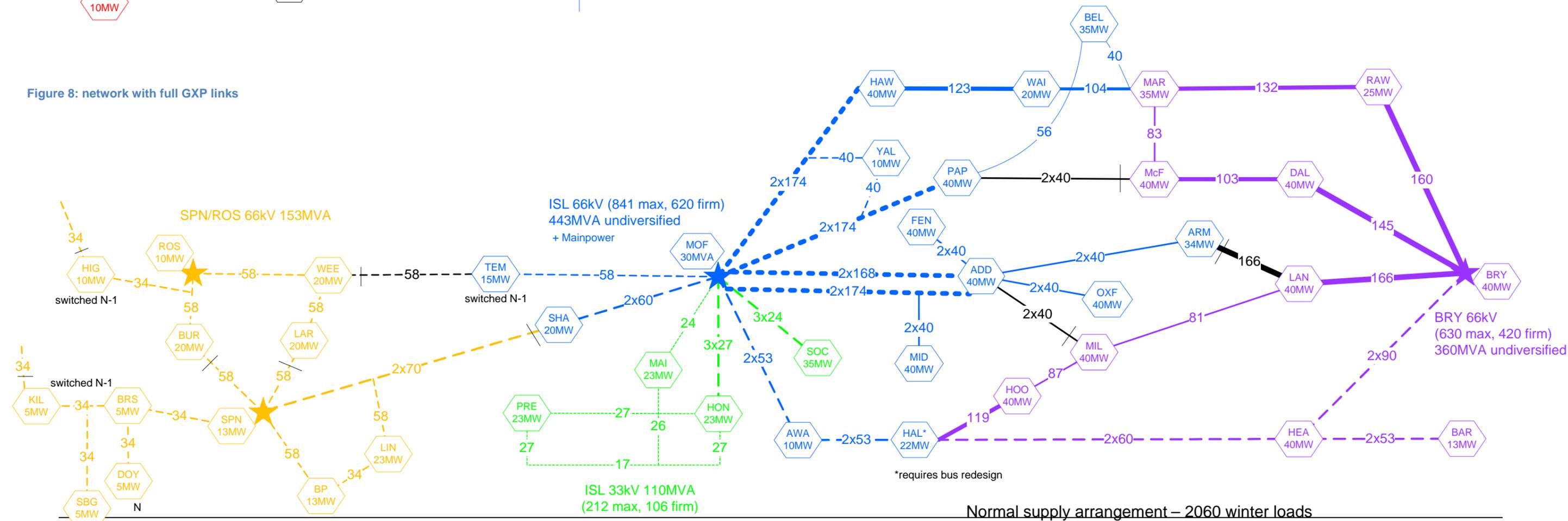


Figure 8: network with full GXP links



The supply to Rawhiti zone substation deserves mention. As a result of the earthquake it is served by a temporary single radial line; the Security Standard requires an N-1 supply. Retaining a single Bromley-Rawhiti circuit would mean an early commitment to the expensive Rawhiti-Marshland link plus either the Marshland-Waimakariri or the Marshland-McFaddens circuits to provide a second independent feed. In addition, space constraints do not permit the construction of a 4-bay bus at Rawhiti for the preferred arrangement of a 2-cable feed through substation.

The economic analysis which follows (for both full and partial GXP links) assumes a single large cable from Bromley to Rawhiti. A number of schemes to provide two feeds to Rawhiti before the provision of supply from the north are under investigation and will take into account the NPV of delaying the links north of Rawhiti.

7.2 N-1 ringed network with partial GXP ties

The approach here is to add zone substations in rings to the existing network, without constructing new cross-GXP links. One new ring is created to the north of each GXP; the rest of the urban network remains largely N-1 radial. McFaddens zone substation sits more naturally in the new Bromley ring and thus the existing Papanui-McFaddens 2x40MVA links become an extra GXP tie.

The diagrams on the next pages show the proposed network with partial GXP links around 2060, assuming all zone substations are at capacity or their expected maximum load. All urban stations are no-break N-1. Some rural stations are switched N-1 or N.

Figure 11 shows existing and planned assets and Figure 12 has the normal operating state.

7.3 Comparing the options

The build costs in the following table refer to those assets to be constructed in the future. This includes the cable network and differences in switchgear. Investments common to both plans (substation sites, transformers etc.) are not included.

Note that an NPV analysis has not been undertaken, as the timing of investment depends on the outcome of the Architecture Review and the unfolding of load growth. Much of the two options consist of equivalent projects (e.g. a Dallington-McFaddens cable) which would be installed at the same time in either option, but with different cost due to different cable size. In this case the project cost is a reasonable basis for comparison as the timing would be the same. There are projects in the full-link option which have no equivalent in the partial-link option (such as uprating the Bromley-Heathcote and Islington-Springston circuits) but these would take place later in the time frame as the load nears network capacity; as such their effect on NPV will be less than earlier projects. Thus an NPV analysis is likely to reduce the cost difference between the options from the absolute build costs listed below.

Cable lengths are derived from realistic measures of practical routes. The loss and capacitance effects are modelled in powerflow software and represent the entire 66kV network in each case (not just the planned extensions).

The 66 kV VOLL of the options is not analysed – both are N-1 schemes with 11kV ties between zones substations and as can be seen from Table 4 the difference in VOLL of interconnected systems is insignificant when compared to other factors.

network cost \$m	cost \$k p.a.	loss effects \$k p.a.	reduction in Var charges \$k p.a.	total cost \$m p.a.
Full GXP ties				
71	7,849	10,115	-340	17.6
Partial GXP ties				
36	3,940	10,188	-303	13.8

Table 7

The annualised difference in total costs is around \$3.8m, before considering the value of the complete vs. partial GXP links.

The increased capacity of the Islington-Springston GXP links (uprating the twin Wolf circuits) would improve Islington support in a Springston/Rosendale contingency. This adds further benefit to the increased link model but this case has not yet been analysed in detail and the following applies to Islington and Bromley outages only.

The partial GXP links will provide full cross-GXP support for a proportion of the time (when the load on the failed GXP is less than the tie support capacity). Loss of load only occurs when the tie capacity is exceeded, so the average annualised VOLL of GXP outages is much lower than when there are no GXP ties.

For the 2060 network with existing (partial) GXP links an estimated 133 MVA peak load would remain unserved following an Islington GXP failure and an estimated 115 MVA following a Bromley GXP failure. This assumes new Selwyn district GXP(s) can supply Islington to the full capacity of the existing Islington-Springston and Islington-Weedons lines.

Both Islington and Bromley load is expected to exceed existing tie capacity 25% of the time, assuming load duration profiles are similar to those of today.

The frequency of HILP events which would justify the cost of full GXP links include the following examples:

- One 7-day GXP outage in 8 years
- One 3-month GXP outage in 100 years

These expectations are much more pessimistic than those for full GXP ties in the idealised 20-substation 800 MW model. Even so, it should be noted that significant events occur in New Zealand at a frequency of several per decade. Examples include the 5-week Auckland blackout in 1998 and the shorter 2006 event (earth shackle failure), the 2009 Otahuhu forklift vs. 200 kV incident, the 2010 and 2011 Christchurch earthquakes, the gas pipeline fault and AUFLS event in 2012, plus numerous weather storms resulting in prolonged regional outages etc.

There are many imponderables involved in planning for major events and a national approach to planning for these would be helpful. HILP events by their nature do not occur in the same way often enough for statistical data to be as useful as it is for more common and repeatable events. From the studies involved in this report there is no indisputable clear-cut economic case either for or against augmenting the cross-GXP links in the Orion network as the way and it becomes a matter of reasonable and prudent judgement.

The immediate issue for Orion is the size of the cables to be installed over the next 2-3 years (Dallington-McFaddens, Bromley-Dallington, Bromley-Rawhiti), and whether to proceed with the proposed Rawhiti-Waimakariri connection. Choosing the smaller cables in the partial GXP link model would rule out the full link option from the beginning, and reduce the options available when future architecture reviews are undertaken. Given the customer and shareholder expectations of a robust power system and the general satisfaction with the recent performance of the existing assets in an extreme event, the recommendation is to plan for full GXP link capacity. Fortunately the staged nature of development means that at some decision points the direction does not need to be locked in and may be reviewed in the light of the pace and location of load growth.

The urban 33 kV network has not been included in the 66 kV ideal architecture analysis. An extra ~95 MVA would be required into the Islington area to cover these substations via 11 kV ties following an Islington 220 kV failure. Under the existing plan for Bromley the maximum interconnection capacity will be 630 MVA and this would be fully utilized in supplying Islington 66 kV load in a 220 kV contingency; any support for the 33 kV network would have to come via 11 kV ties from zone substations fed from Springston/Rossendale GXPs. The interconnection capacity of these future GXPs is yet to be determined, but the subtransmission links into Islington would have to be reinforced by an extra 95 MVA over the capacities assumed in the “full GXP links” plan.

The economics of this would be challenging (although overhead circuits are cheaper than cable) and would require a separate study. However choosing the stronger GXP link architecture in conjunction with modifications to the rural 66 kV network will provide greater options in the future.

8 Sub-transmission switchyard layout options

Process

Numerous conceptually possible layouts were considered and existing Orion substations were reviewed to give a set of layouts to examine. These included conventional bus layouts as typically used by Transpower and ring bus layouts as used by Orion in recent years.

Starting with 6 circuits and 2 transformers, the options were drawn up and worked backwards to 1 circuit and 1 transformer to eliminate options that didn't provide an incremental transition path.

The value of having a bus coupler was determined for various configurations.

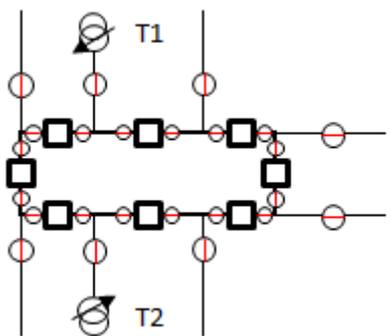
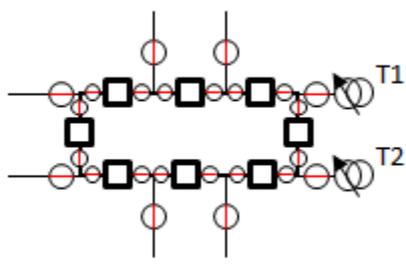
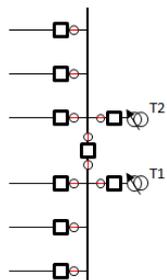
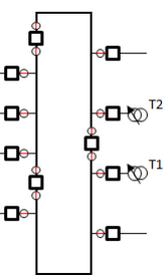
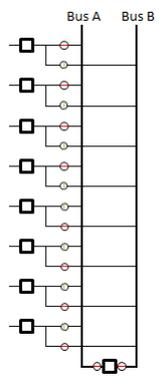
Resilience to a range of faults was checked (including considering the interaction with neighbouring switchyards for dual circuit failures) and land area needs were reviewed.

When considering switchyard layouts note there are external variables to the substation that could alter its layout:

- 3 circuit terminal. Circuits that are Tee'd together outside of a substation without the use of any switchgear. This mainly occurs in the rural overhead network, but examples can be found in the urban network i.e. Middleton.
- Layout of neighboring substations. A substation with 2 circuits will require a neighboring substation with 3 circuits to ensure switchable N-2 (this is shown later in this section).
- Future expansion. Extra circuit breaker bays require extra space and integration into the existing layout.

6 Circuits, 2 Transformers – Options

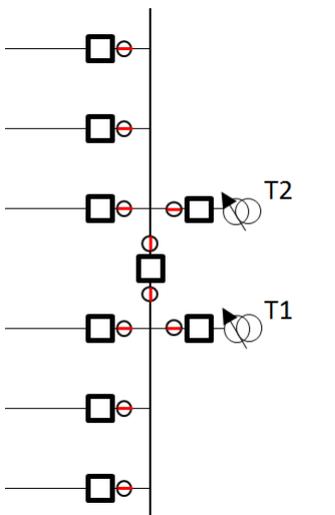
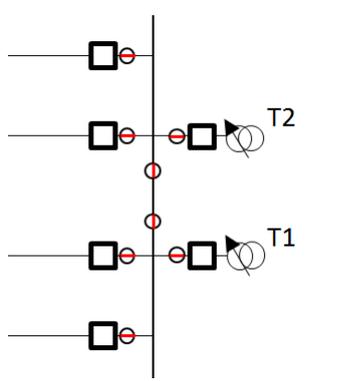
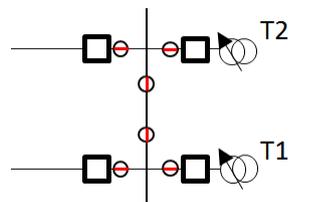
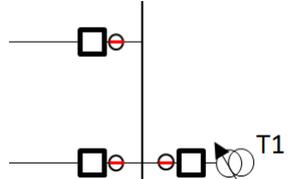
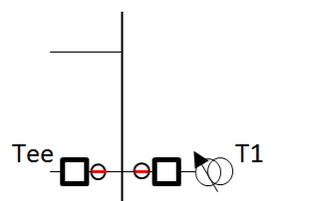
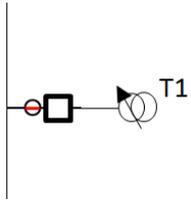
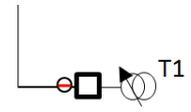
All options have disconnectors enabling a CB or transformer to be removed from service without affecting the operation of the remaining plant.

 <p>Ring Bus 1A</p> <p>This option has the circuits connected between the transformers. It allows for 2 rings to operate and is robust for Circuit, Tx, CB and Bus faults.</p>	 <p>Ring Bus 1B</p> <p>Transformers are adjacent without a circuit connected between them. If a CB fails between the 2 transformers, both Transformers will be lost.</p>
<p>2 – Conventional</p> <p>With a bus coupler it has 1 more circuit breaker than a ring bus.</p> <p>Note that a bus coupler fault causes a complete bus/station shutdown and may also affect neighbouring substations.</p> 	
 <p>3 –Conventional Bus Ringed</p> <p>More equipment, cost and no advantage over ring bus. Therefore not considered further.</p>	 <p>4 - Conventional double bus-bar.</p> <p>Any circuit is able to operate on either bus. However this layout does require many ABI's and an extra CB than a ring bus. Therefore not considered further.</p>

Appendix G compares the performance of Ring Bus 1A and 1B for network faults. It shows that 1A gives better performance for Transformer and Circuit Breaker faults.

Conventional Bus

The transition from 6 circuits, 2 transformers to just one circuit and transformer is shown here:

 <p>Site fully developed with 6 circuits, two transformers and a bus coupler*</p>	 <p>Site with 4 circuits and 2 transformers, without bus coupler*. There are 2 disconnectors on the middle of the bus to enable one to be taken out for maintenance without isolating the whole bus which would cut of supply to both transformers</p>	 <p>Site with 2 transformers and 2 circuits can readily be extended to incorporate a 3rd circuit</p>
 <p>Simple 2 circuit, 1 transformer site with ability to feed through between adjacent sites. Vulnerable to bus fault.</p>	<p>Alternative 2 circuit option</p> 	<p>Alternative 2 circuit option</p> 
 <p>1 circuit, 1 transformer</p>	<p>Single source with a radial tee so no need for a CB on the source side</p>	<p>2 circuit with single tee to transformer. Fault on either circuit prevents load being supplied therefore not preferred</p>

- *Appendix C gives the analysis of the value of having a bus coupler. It shows that it is not economic to have a bus coupler for 40 MW substations with less than 6 CB (4 circuits and 2 transformers). At this point the economics are close to breaking even using a pessimistic CB failure probability, therefore a bus coupler is not justified unless there are more than 4 circuits and 2 transformers. This conclusion holds true with the proposed design of the 66kV subtransmission network which for the loss of two 66kV circuits during a bus fault the 66kV supply to surrounding substations is still live. For sites with three or more 66kV circuits the economics of a bus coupler on a conventional bus need to be checked on a case by case basis.

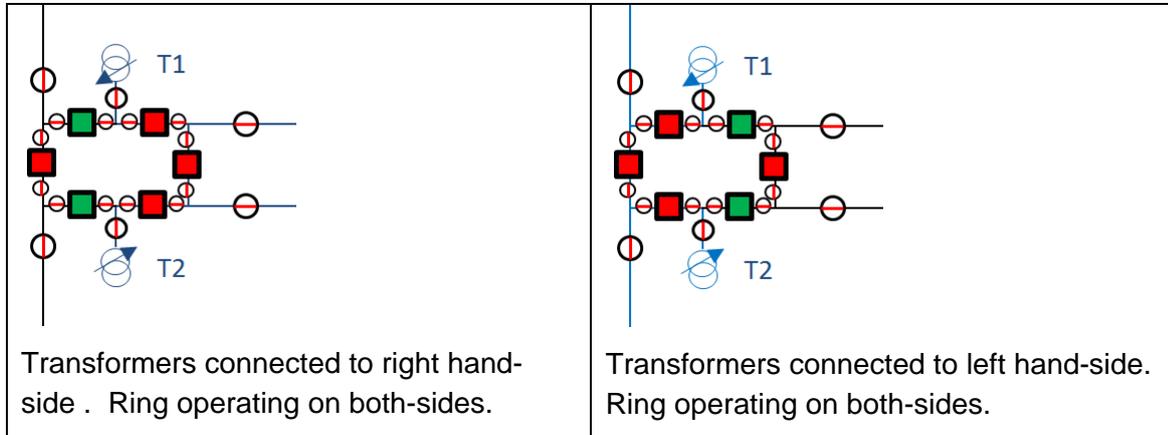
Ring Bus

<p>For a CB fault only 1 Transformer or 1 circuit is lost. No load lost.</p>	<p>Added security with 4th CB, however 2 Transformers or both circuits could be lost for a CB fault. Therefore not preferred.</p>	<p>Only 3 CB's used. No load lost for a circuit fault or a Transformer fault.</p>
<p>Single Transformer will stay live if either circuit is lost. If Transformer trips then circuit not fed through until ABI switched. Fits in well with above layout going forward.</p>	<p>Single Transformer will stay live if either circuit is lost. Design doesn't fit in with more circuits going forward.</p>	<p>Simple.</p>

Switching between GXP rings

The proposed 66kV network design and regulatory requirements (which can be overcome but are not economically justified) prevent permanent connection between 66kV GXPs.

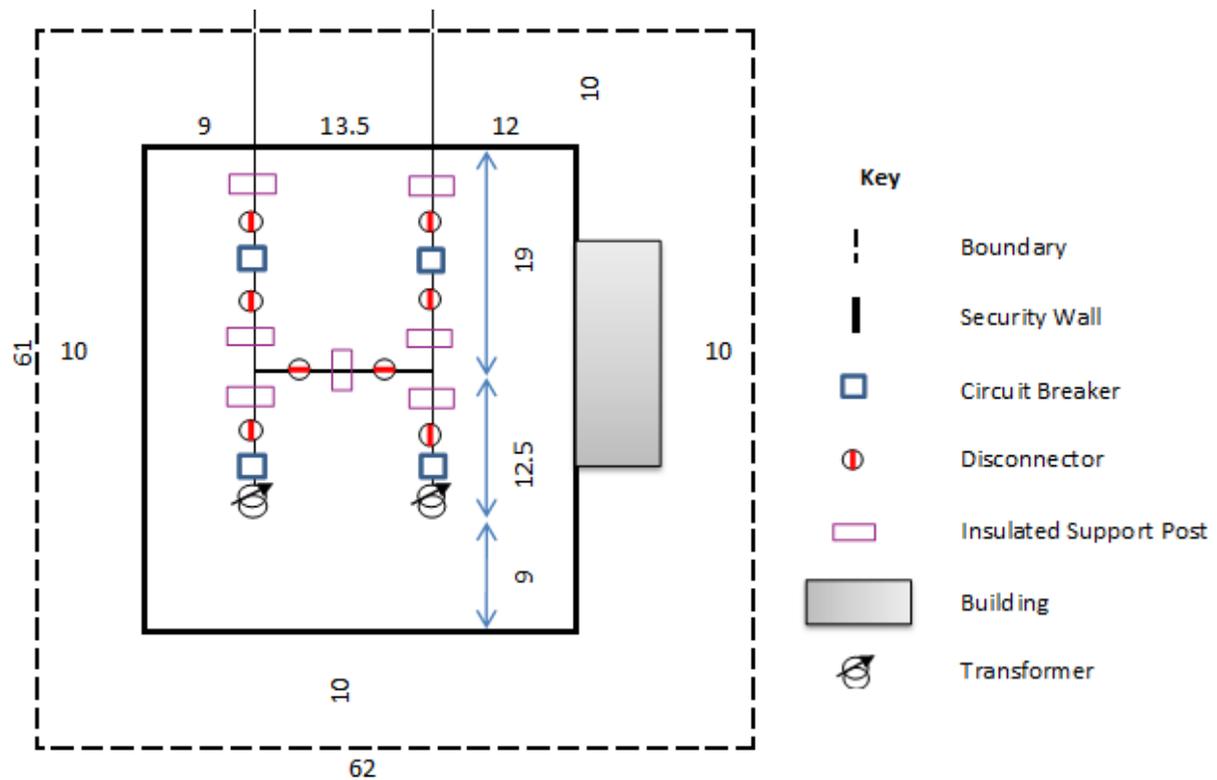
The following shows how Ring Bus 1A layout has the flexibility to allow a substation to be switched between an Islington GXP ring and a Bromley GXP ring. If a conventional bus was used, 2 busses (or 4 to avoid outages for bus faults) would be required.



Site Development

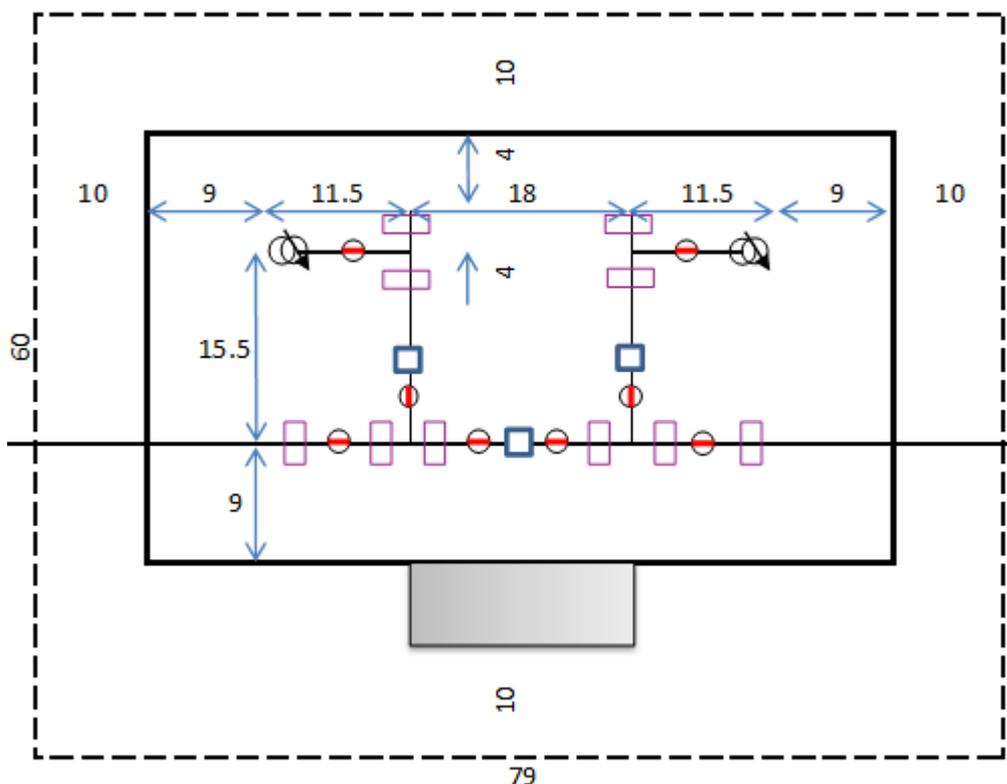
To understand 66 kV zone substation site development options the analysis now changes from Single Line Diagrams to site layouts. Appendix D shows how a site develops from 1 circuit, 1 transformer up to 4 circuits, 2 transformers for each bus option. Dimensions/spacings are based on recent substations constructed in Orion's network.

It is considered prudent to allow sufficient land to develop up to at least 2 circuits and 2 transformers (or in some cases 4 circuits – depending on the location within the network). For the 2 circuit case the conventional bus arrangement is shown in the following figure:



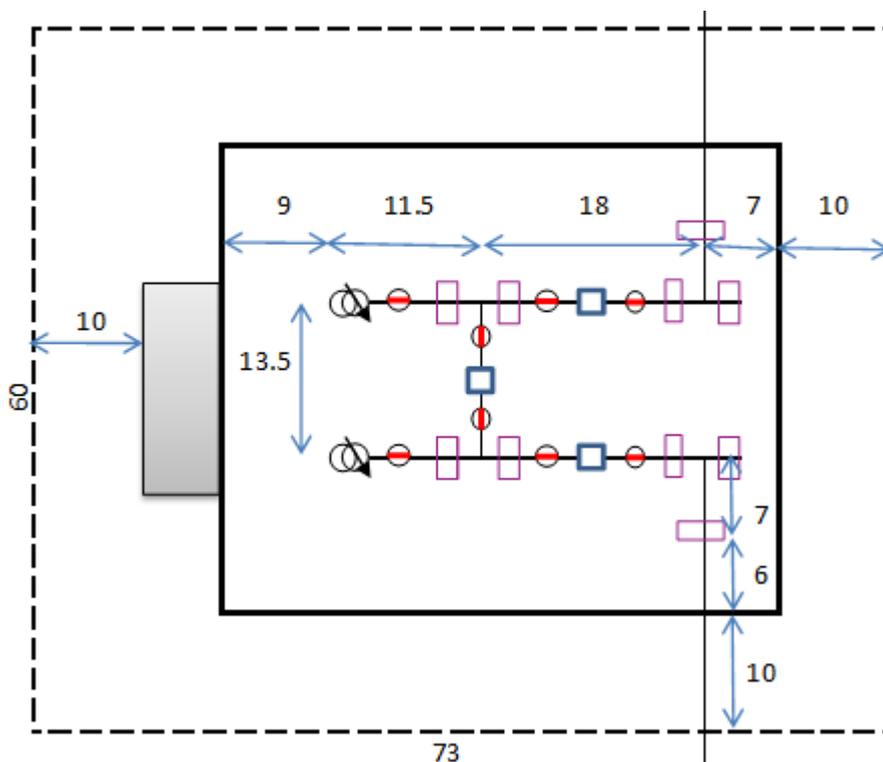
Of the options covered this has the smallest footprint of ~3700 m², but requires four circuit breakers.

The Ring Bus A option (with transformers opposite) is:



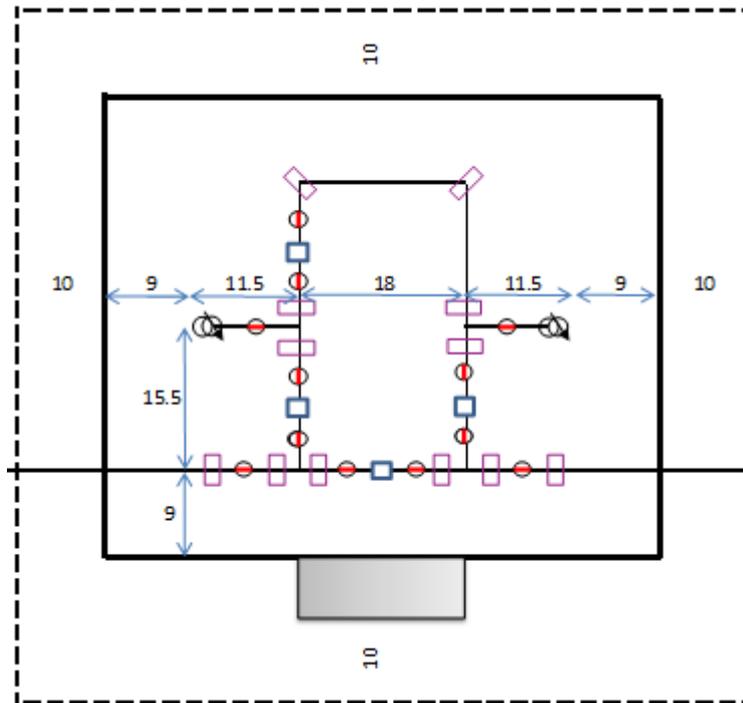
Although this has a larger footprint of ~4700 m² it requires only three circuit breakers. The extra land cost is more than compensated for by the reduction of a circuit breaker. Reliability is also improved through having less circuit breakers. See Appendix E for economic analysis.

The Ring Bus B option (with transformers adjacent) is:

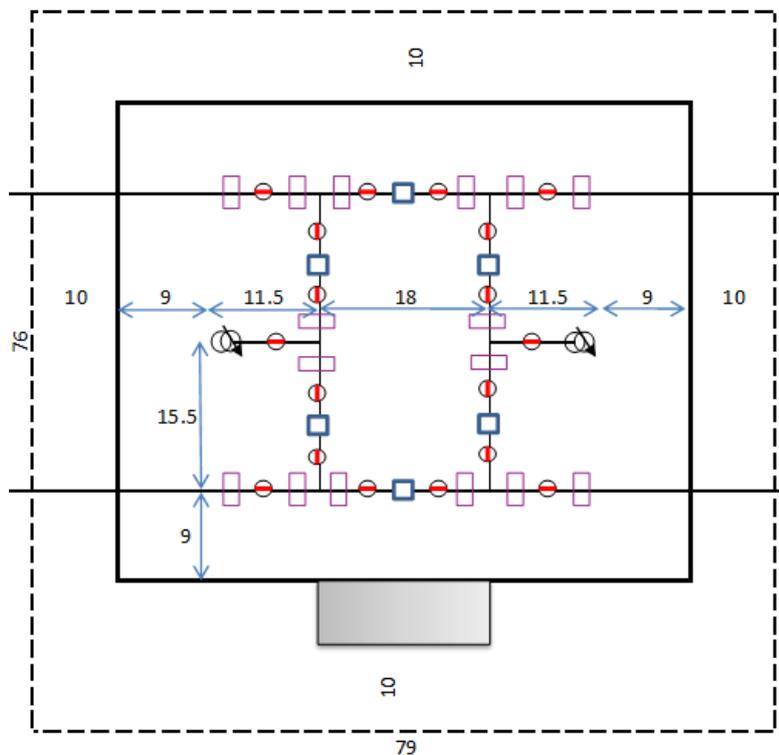


This has a slightly smaller footprint than Ring Bus A option at ~4300 m². However unless land is extremely tight and expansion to a third circuit is never going to be required, Ring Bus A option is preferred as it has better fault performance as shown in Appendix G.

If the zone substation is connected to other zone substations in such a way that through connectivity between the two circuits needs to be maintained with the middle circuit breaker out, then Ring Bus A option can be extended as shown below:

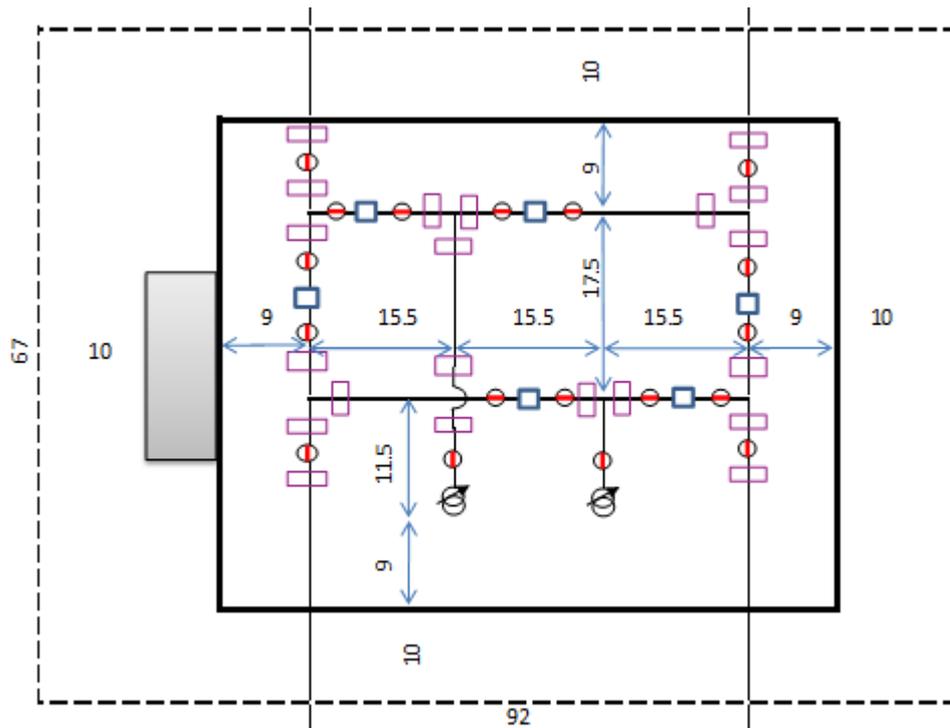


This layout facilitates the addition of further circuits, eg 4 circuits, 2 transformers as shown here:



For all 3 options (Conventional, Ring Bus A, Ring Bus B), the development up to 4 circuits and 2 transformers requires 6 circuit breakers in all options, and the land difference reduces. Hence there is no sufficient reason to choose an alternative bus configuration going beyond 2 circuits. The analysis in appendix E shows that Ring Bus A is the most economic for 3 or 4 circuit substation.

A variation of Ring Bus A with a transverse bus crossing over a bus to give adjacent transformers was considered as shown below.



However this requires more land at each stage of development, and would need both transverse buses to be isolated for safety if work is carried out on either of them.

Therefore Ring Bus A option (transformers opposite) is the preferred option, providing a suitable development path as the number of circuits and transformers increases. This option also has the advantage of greater separation between transformers which reduces the risk from an explosion in one transformer damaging the other transformer. Ring Bus B (transformers adjacent) provides an alternative for an area constrained site that will require no more than 2 circuits, and the ability to feed through to an adjacent substation is not required.

Implications of bus design on the subtransmission system

For High Impact Low Probability (HILP) events, the requirement that two 66kV cable/line faults must not affect any more than one zone substation means that every other substation will require a third circuit.

This ensures neighbouring substations have sufficient capacity to provide support for the effected zone substation.

The network shown to the left shows:

- 2 subs with 3 circuits and
- 2 with 2 circuits.

2 cables faults shown result in loss of 2 transformers at 2 different sites and no loss of load. The 3rd cable would have sufficient to keep the load going to both.

2 cables faults shown result in loss of a whole substation. The substations either side still have enough capacity left to meet their own load of 40 MVA plus another 20 MVA each making up for the 40 MVA lost.

Comparison of Ring Bus Verse Conventional

Ring

- Better fault performance eg Only 1 feeder tripped for a Bus fault, 2 CB's & 2 feeders tripped for a CB fail
- Can provide switching for 2 separate GXP rings
- Bus protection is simple as each section is small (see Appendix E for details)

Conventional (No Bus Coupler)

- Requires extra CB for 2 transformer, 2 circuit configuration
- Easier to extend
- Can be more compact in size
- Whole bus section lost for a CB fault
- Additional CB bays need to be added into the bus protection. More complex than for a ring bus.

9 Modelling tool

We have developed a network investment and reliability performance modelling tool which essentially allows a variety of network architectures to be analysed in terms of their construction costs and reliability performance. In this way capital investment and operations **costs** can be compared to the value that customers put on the reliability **benefits**.

The model and the data input assumptions (construction costs, fault rates, value of unserved energy, etc.) have been developed internally and have been subject to an internal review involving network development, asset management, operational and commercial staff members. This process has enabled the quality of input data assumptions and also the output calculation accuracy to be thoroughly challenged and checked.

Participants include GM Development, Network Planning Manager, GM Infrastructure, Operations Manager, Engineering Manager and the Commercial Analyst.

The model input values that have been used are shown in Appendix B.

10 Recommendations

It is recommended that future extensions to the Orion subtransmission network be in closed-ring N-1 topologies with plans for sufficient cross-GXP link capacity¹⁵ to provide full support in the loss of either urban 66 kV supply.

The recommendation for Dallington and Rawhiti will be written following feedback on this draft of the report.

11 kV tie capacity between adjacent zone substations should allow a substation's complete load to be carried by two neighbouring substations as a general principle (exact tie support details will depend on the number and location of adjacent substations and specifics of existing 11kV assets).

Ring bus A design be incorporated into Orion design standards for 66 kV switchyard design. This requires land area of ~60 m * ~79 m for a two circuit, two transformer site with a 10 m landscaping/noise buffer. For the development of sites with potential for three to four circuits in the future, the land area required is ~76 m * ~79 m. Deviations from this design may be appropriate where supported by documentation outlining the engineering or economic reasons.

To facilitate further analysis in the future it is recommended that Orion starts capturing data on circuit breaker failures and bus faults.

To improve knowledge of the extent of outages it is recommended that Orion develops functionality in Power On to calculate kWhrs lost during faults. This will enable the cost of outages to our customers to be more accurately modelled than is currently possible using the SAIDI and SAIFI indices.

To formalise a new value for VOLL it is recommended that we continue to work with the Electricity Authority to produce updated VOLL values in the following format.

	Outage duration					Discount factor (1)
Customer Category	10 min (2)	1 hour	3 hour	8 hours	2 days (3)	
Small industrial						
Commercial						
Agricultural						
Residential						

1. Assuming that the values in the above table would be VOLL at the worst possible time it would be useful if a typical discount value (%) to take account of season, day of week and time of day
2. In the absence of a 5-10 second value, we would use the 10 minute value to assess the impact of momentary outages caused by auto reclose operations or auto switching schemes which shift load post contingency
3. Supporting discussion about direct and indirect costs and the treatment of asymmetric risk for high impact low probability events is just as important as a VOLL value

¹⁵ It is understood that while the complete plan consists of rings with full GXP link capacity, the development stages may involve radial spurs or less than full GXP link capacity while load grows to justify more timely and economic upgrade capacity, as permitted under the Security of Supply Standard and supporting economic analysis.

11 Appendix A Network topologies

In the following diagrams, the numbers on the links refer to cable capacity as in Table 1.

1	N radial	no GXP links	restore 66kV in repair time for single fault	restore load by switching 11kV for single 66kV fault
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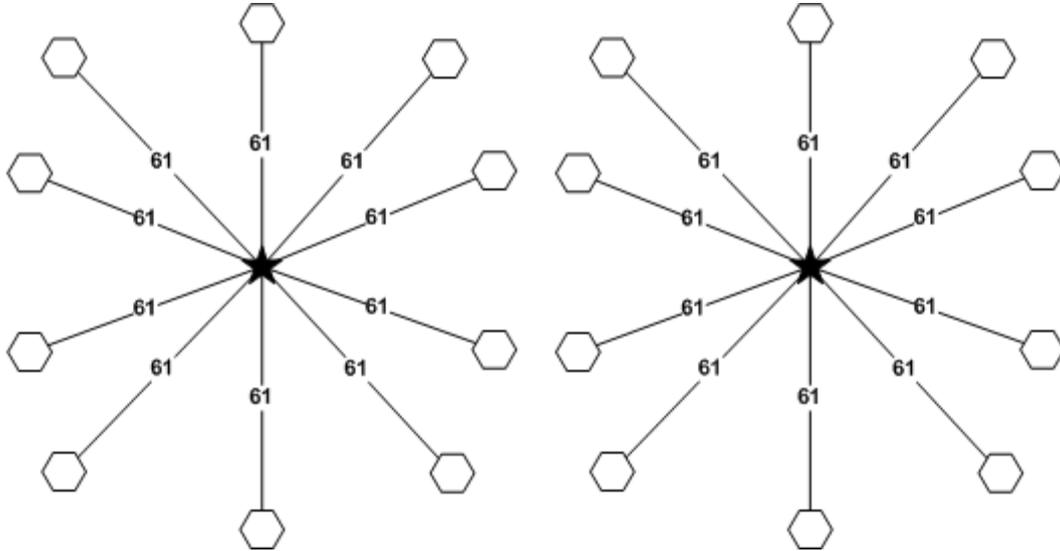


Figure A1: N radial without GXP links

Single cable to each substation (one transformer); no breakers at substations.

2	N-1 radial	no GXP links	no break in 66kV for single fault	restore load by switching 11kV (max. 1 sub) for 2 66kV faults
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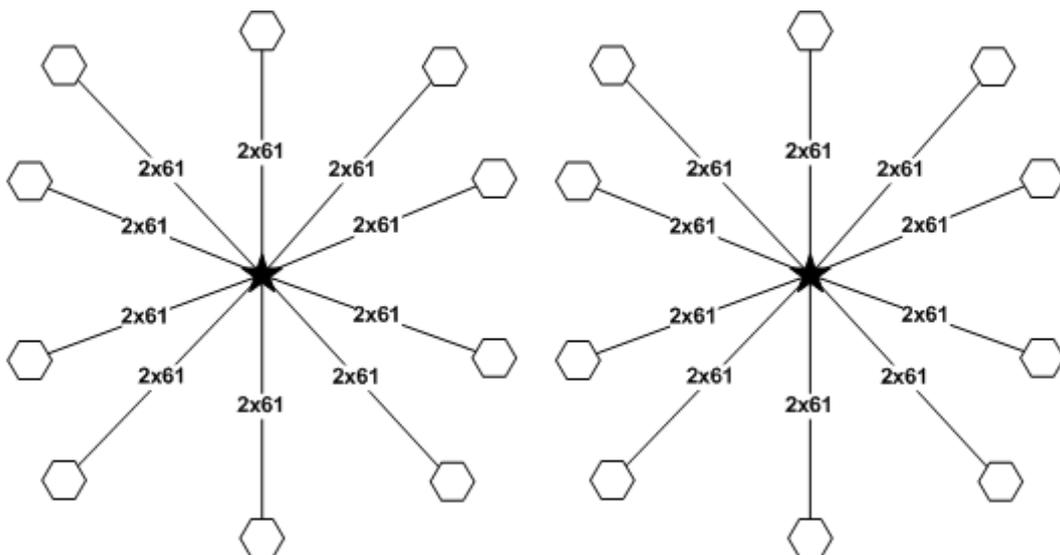


Figure A2: N-2 radial without GXP links

Two cables to each substation (two transformers); no breakers at substations.

3	N-1 rings	no GXP links	no break in 66kV for single fault	restore load by switching 11kV (max. 1 sub) for 2 66kV faults
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These designs have two transformers and at least two cables per substation, with a 66kV bus and breakers.

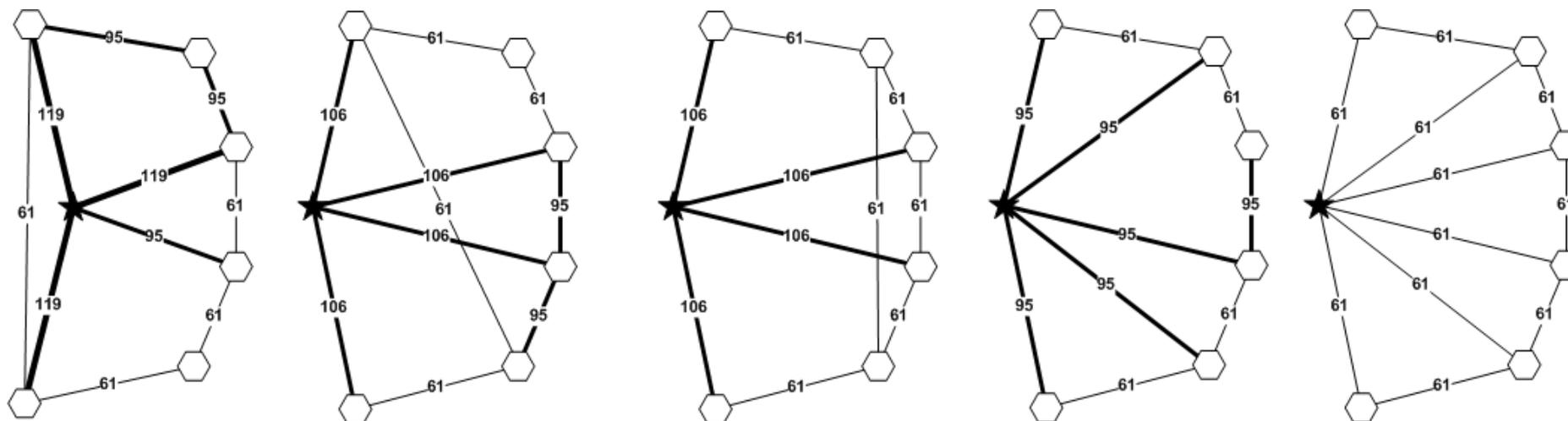
Cable sizes are chosen to ensure that for the loss of any 2 cables all the load may still be supplied (if a zone sub loses 66kV, neighbouring subs carry the load via 11kV ties).

All substations operate in closed rings providing continuous supply in the event of a single 66kV fault.

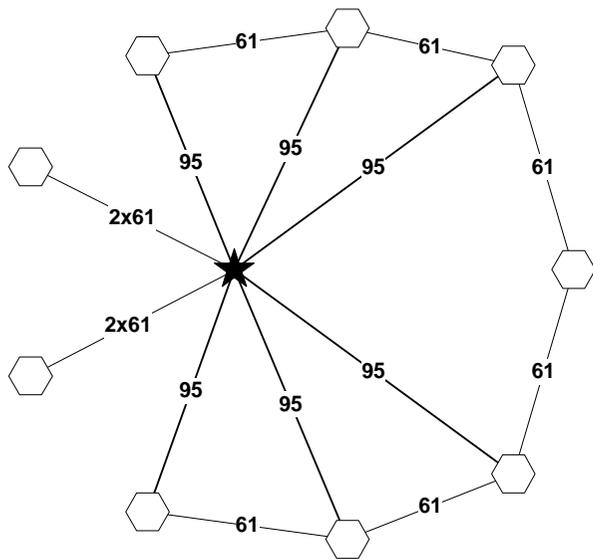
There is a number of possible ring arrangements of 18 zone substations, such as

- 2 rings of 9 subs
- 3 rings of 6 subs
- 2 rings of 4 subs + 2 rings of 5 subs
- 6 rings of 3 subs
- 9 rings of 2 subs

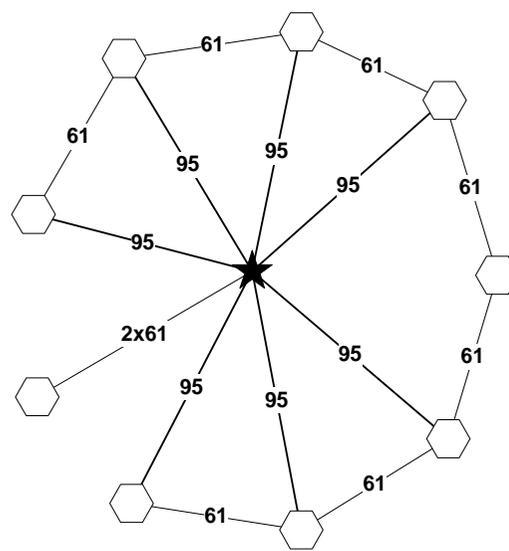
In addition, each arrangement has different permutations – for example, a ring of 6 substations could take the following forms and more:



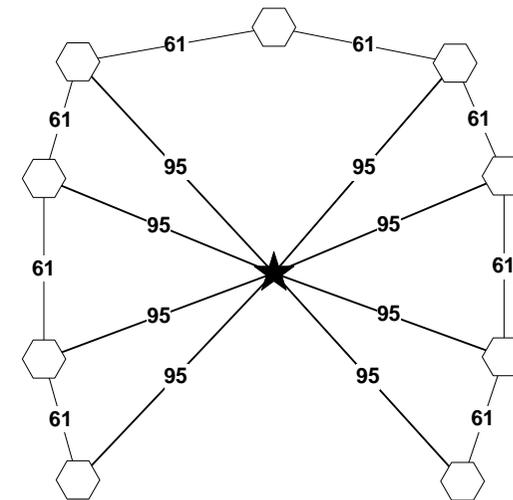
Clearly there are dozens of possibilities. Preliminary studies identified the most likely candidates for further investigation (Figure A3).



(a)



(b)



(c)

Figure A3: N-1 rings without GXP links

4	N-1 radial	GXP links	restore 66kV in switching time for single fault (possibly fast automated switching)	restore load by switching 11kV (max. 1 sub) for 2 66kV faults
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These designs have two transformers and at least two cables per substation, with a 66kV bus and breakers.

Cable sizes are chosen to ensure that for the loss of any 2 cables all the load may still be supplied (if a zone sub loses 66kV, neighbouring subs carry the load via 11kV ties).

Radial networks with GXP links consist of branches of substations connecting the GXPs with an open point. Because of Assumption 6 the designs are “nearly N-2;” rather than strictly radial there are extra links allowing groups of substations to be operated as closed rings. Not all substations are in closed rings, and a cable fault can result in outages which are restored by switching open points. Intelligent protection and control systems could provide for rapid sensing of fault conditions and automated switching (~300ms).

There is a number of possible radial arrangements of 18 zone substations, such as

- 2 branches of 9 subs
- 3 branches of 6 subs
- 2 branches of 4 subs + 2 branches of 5 subs
- 6 branches of 3 subs
- 9 branches of 2 subs

Each arrangement has different permutations and preliminary studies identified the most likely candidate for further investigation (Figure A4).

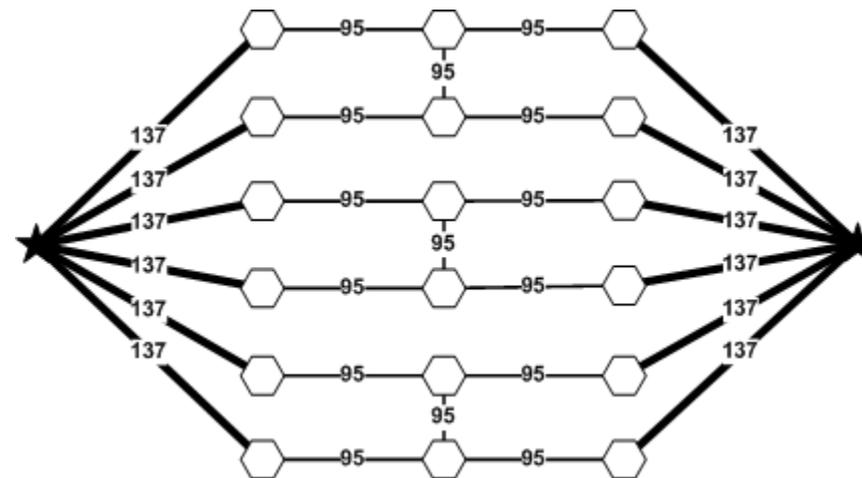


Figure A4: N-1 radial with GXP links

5	N-1 rings	GXP links	no break in 66kV for single fault	restore load by switching 11kV (max. 1 sub) for 2 66kV faults
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These designs have two transformers and at least two cables per substation, with a 66kV bus and breakers.

Cable sizes are chosen to ensure that for the loss of any 2 cables all the load may still be supplied (if a zone sub loses 66kV, neighbouring subs carry the load via 11kV ties).

All substations operate in closed rings providing continuous supply in the event of a single 66kV fault.

Numerous arrangements are possible. The networks in Figure A5 were chosen for further analysis:

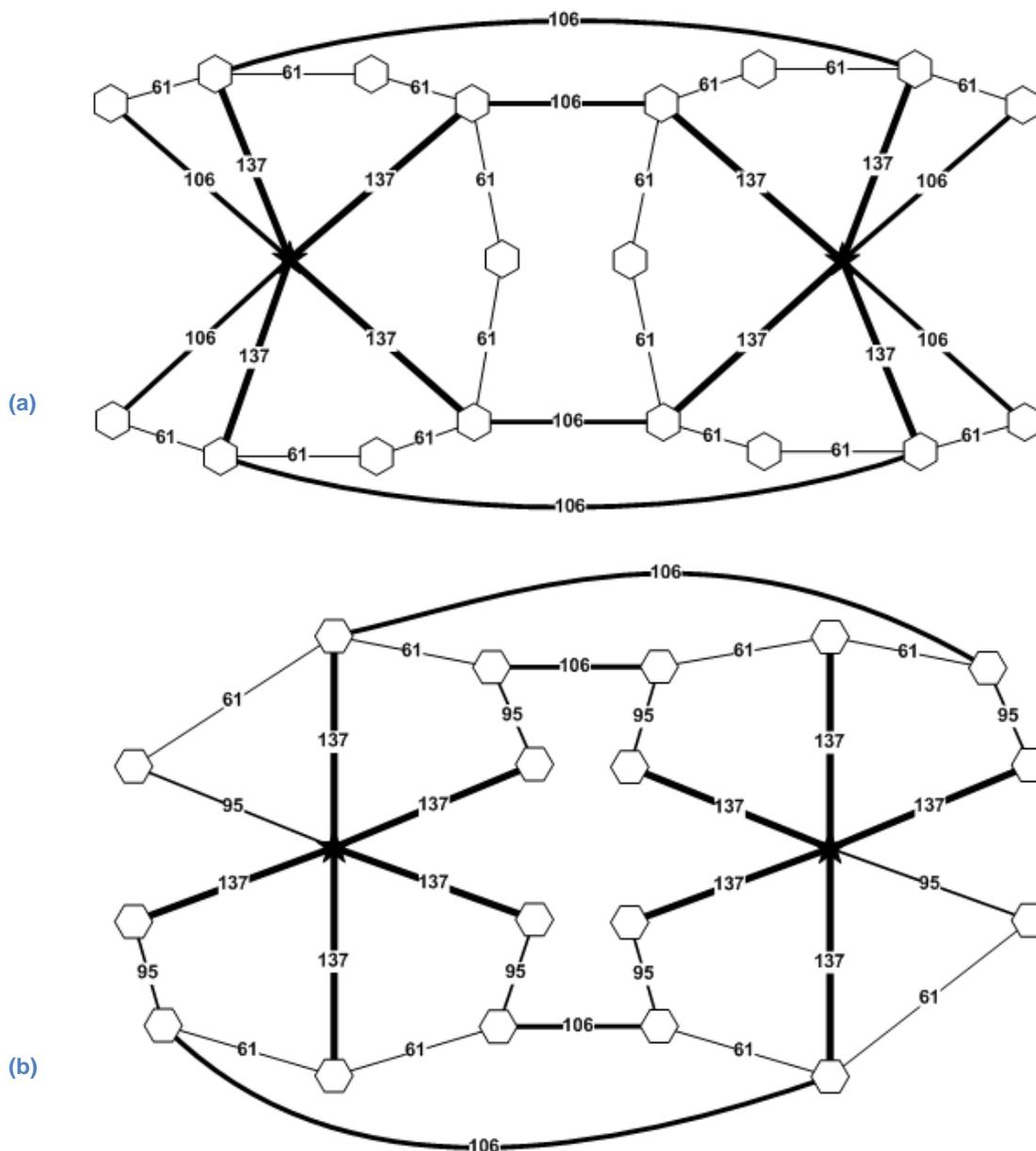


Figure A5: N-1 rings with GXP links

6	N-2 rings	GXP links	no break in 66kV for 1 or 2 faults
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These designs have two transformers and at least three cables per substation, with a 66kV bus and breakers.

Cable sizes are chosen to ensure that for the loss of any 3 cables all the load may still be supplied (if a zone sub loses 66kV, neighbouring subs carry the load via 11kV ties).

All substations operate in closed rings providing continuous supply in the event of a single or double 66kV fault. This arrangement provides N-2 security for cable or switchgear faults but N-1 for transformer (or transformer breaker) faults. Given the lower incidence of transformer failures, this is a reasonable option. In the economic analysis, a variant with 3 transformers per substation (full N-2) is included for comparison.

Numerous arrangements are possible. The networks in Figure A6 were chosen for further analysis (the top one relies on the GXP bus being usable in a contingency):

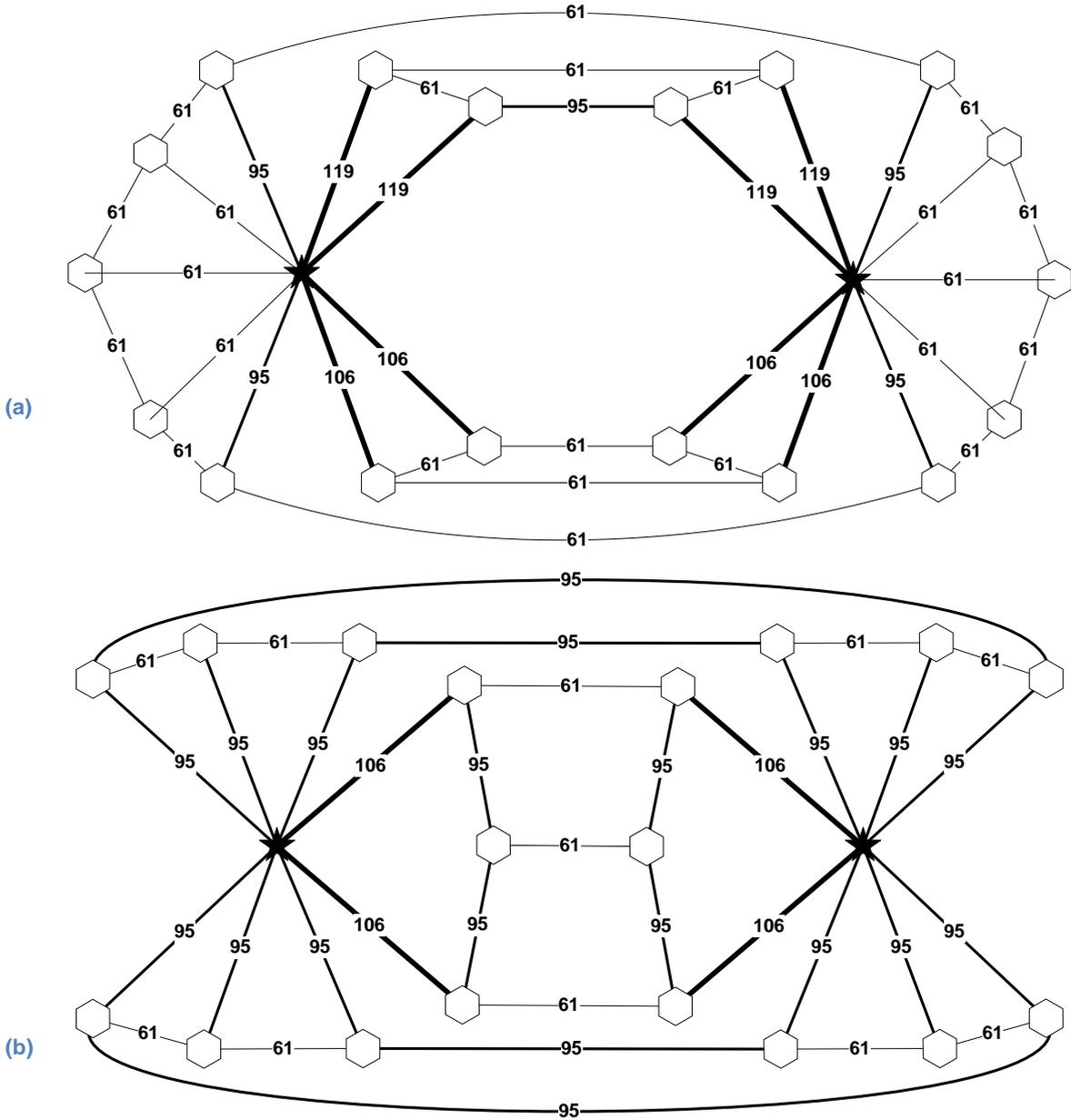


Figure A6: N-2 rings with GXP links

12 Appendix B Model Inputs

The **equipment failure rates** in the last column of the following table have been applied to the reliability and economic analysis model.

Asset Reliability Assumptions	2006 Review	EEA Guide Rate	IEEE Standard 493	Orion Risk Management Plan	Orion 2006 - 2011 Urban Avg	Orion 2006 - 2011 Rural Avg	Proposed 2011
	Faults per item or km pa	Faults per item or km pa					
66kV cable	0.02	0.01	0.02	0.011	0.005	-	0.01
33kV cable	0.02			0.011	0.014	0.032	0.02
66kV line	0.03			0.03	0.003	0.015	0.03
33kV line	0.03			0.04	0.022	0.039	0.04
66/11kV Xfmr	0.02	0.02	0.015	0.012	0.011	0.000	0.02
33/11kV Xfmr				0.012	0.000	0.030	0.02
66kV Bus	0.002	-	0.002				0.002
33kV Bus	0.002						0.002
66kV CB	0.025	-	0.018	0.002			0.02
33kV CB	0.025			0.002			0.02
11kV Bus	0.015	0.015	0.0036				0.015
11kV CB	0.02	0.015	0.0036	0.002			0.002
11kV cable & kiosks	0.035	0.04	0.03	0.024	0.026	0.035	0.03

The 66 kV/33 kV CB proposed faults rate may be high, but we have no evidence to support lowering these. This data is used for assessing the economics of a bus coupler in a conventional switchyard. Using 0.02 indicates the bus coupler is not justified and lower rates would further reduce the economics for a bus coupler. This review recommends a ring bus rather than a conventional bus arrangement so lower fault rates would not change this.

The 2006 – 2011 Orion data points come from a statistically small dataset for all but 11 kV data so provide a limited reality check.

Repair times have been updated and refined to reflect various failure modes as shown in the following table.

Asset	2006 Repair time hrs	2011 Proposed Repair time hrs	Notes
66kV cable - cable	240	330	XLPE 240, Oil filled 336 (14 days) - delay getting jointer onsite.
66kV cable - protection		6	
33kV cable - cable	240	72	
33kV cable - protection		6	
66kV or 33kV line	12	12	
66/11kV or 33/11kV Xfmr - urban	72	72	Urban Xfrm has more complex configuration requiring 4 days for swap, or 2 days for onsite repair
66/11kV or 33/11kV Xfmr - rural		48	Rural Xfrm takes 2 to 3 days for swap, or 2 days for onsite repair
66kV Bus	48	48	eg Transpower dropper fails
33kV Bus	48	48	Indoor could be weeks
66kV CB	48	48	Indoor would be longer
33kV CB	48	48	
11kV Bus	96	96	
11kV CB	24	24	
11kV cable & kiosks	8	10	Ranges from 8 to 12 (faults at night take longer)

Had 1 cable repair truck/crew, looking to get 2nd one
 Line faults - bring in resources as needed to repair all within 5 days

Capital Costs have been updated with the following:

Asset Description	Cost
66/11kV Site land. Location dependant. For 4700m2: \$50k - \$700k	
Rural - Establish substation site + 11kV building, fencing	\$801,000
66/11kV 40 MVA xformer + protn installed incl pad	\$1,549,000
66/11kV 23 MVA xformer + protn installed incl pad	\$1,311,000
66/11kV 10 MVA xformer + protn installed incl pad	\$1,013,000
66kV substation bay with breaker and protection	\$361,000
66kV bay without breaker	\$154,000
Single circuit 300Cu XPLE cable/m installed > 1 km	\$730
Single circuit 630Cu XPLE cable/m installed > 1 km	\$890
Single circuit 800Cu XPLE cable/m installed > 1 km	\$960
Single circuit 1000Cu XPLE cable/m installed > 1 km	\$1,090
Single circuit 1200Cu XPLE cable/m installed > 1 km	\$1,170
Single circuit 1600Cu XPLE cable/m installed > 1 km	\$1,350
Double circuit 300Cu XPLE cable/m installed > 1km	\$1,040
Double circuit 630Cu XPLE cable/m installed > 1 km	\$1,350
Double circuit 1200Cu XPLE cable/m installed > 1 km	\$1,910
Double circuit 1600Cu XPLE cable/m installed > 1 km	\$2,290
33/11kV 23 MVA xformer + protn installed incl pad	\$1,013,000
33kV outdoor circuit breaker	\$87,000
33kV indoor bay + zone and bus prot.	\$207,000
33kV indoor bay + basic o/c protection	\$138,000
33kV 300Al three single core cables per set + pilot	\$153
11kV cable laying - Transit (high traffic)	\$210
11kV cable laying - Rural berm	\$63
11kV 95 mm Al XLPE 3c, no pilot	\$34
11kV 300 mm Al XLPE 3c, no pilot	\$59
Pilot 7 pair	\$5

11 kV cable laying costs here are based on reinforcement projects rather than subdivision development and hence are at the high end of the range.

Asset Description	CAPEX	Components
Network Substation land and building	\$154,000	
Land		\$10,000
Legal/Title		\$9,000
Building		\$122,400
Design		\$13,000
11kV 630A CB with remote indication and control	\$52,000	
11kV 1250A CB with remote indication and control	\$61,000	
11kV 2500A CB with remote indication and control	\$103,500	
11kV zone protection -solkor	\$3,000	
MSU (2K1T)	\$38,100	
MSU		\$22,100
Kiosk - land consideration		\$2,000
Kiosk - legal/easement survey		\$4,500
Kiosk (full) shell and pad		\$9,500
MSU (3K1T)	\$42,300	
11kV MSU switch + cable termination - Marginal cost per circuit		\$4,200
XIRIA RMU 2*630A switches/2*500A CB without remote ind and ctrl	\$66,000	
XIRIA		\$23,600
GE F35 Protection Relay + rack		\$13,505
Assembly/wiring		\$7,000
2 sets CTs		\$970
Kiosk - land consideration		\$4,000
Kiosk - legal/easement survey		\$4,500
New XIRIA/Transformer kiosk		\$12,000
XIRIA RMU 2*630A switches/2*500 CB with remote ind and ctrl	\$77,000	
XIRIA KKTT		\$32,400
GE F35 Protection Relay/"RTU" + rack		\$13,505
Assembly/wiring		\$10,000
2 sets CTs		\$970
Kiosk - land consideration		\$4,000
Kiosk - legal/easement survey		\$4,500
New XIRIA/Transformer kiosk		\$12,000

Alternative Ring Main Unit options are being investigated. It is anticipated that there will be an option at lower cost than the XIRIA, and that MSUs will be phased out.

Operations and maintenance costs have been determined based on a years worth of records. This showed the average cost is \$28 for onsite manual switching compared with \$4 for remote switching via SCADA.

Regarding remote indication and control:

- SCADA system cost is a separate consideration as SCADA justified for overall business operation
- Indication much more valuable than Control
- Consider use of 'smart meter' at kiosk (comms cost to be included in Opex)

13 Appendix C Bus Coupler Analysis

Peak demand (kW)	40000						
Load factor	0.6						
Switching time to restore from bus fault assuming 11kV back up(hrs)	1						
VOLL (\$/kWh)	23						
Probability of bus fault	0.002						
Annual Capital, Maintenance and Operations recovery factor	14.6%						
Probability CB failure (either catastrophic or fail to open)		0.002	0.005	0.01	0.015	0.02	0.025
Number of circuit breakers		VOLL improvement of bus coupler					
in an out and two transformers	4	\$5,520	\$12,144	\$23,184	\$34,224	\$45,264	\$56,304
3 ccts and two transformers	5	\$6,624	\$14,904	\$28,704	\$42,504	\$56,304	\$70,104
4 ccts and two transformers	6	\$7,728	\$17,664	\$34,224	\$50,784	\$67,344	\$83,904
minus VOLL reduction because of bus coupler		\$1,104	\$2,760	\$5,520	\$8,280	\$11,040	\$13,800
Capital expenditure justified by VOLL improvement of bus coupler	4	\$30,247	\$64,274	\$120,986	\$177,699	\$234,411	\$291,123
	5	\$37,808	\$83,178	\$158,795	\$234,411	\$310,027	\$385,644
	6	\$45,370	\$102,082	\$196,603	\$291,123	\$385,644	\$480,164

Average time to connect customers - some will be reconnected almost immediately and others up to 2 hours

Bus coupler is an extra asset that can fail and therefore in itself can create a loss of supply

Input Information:

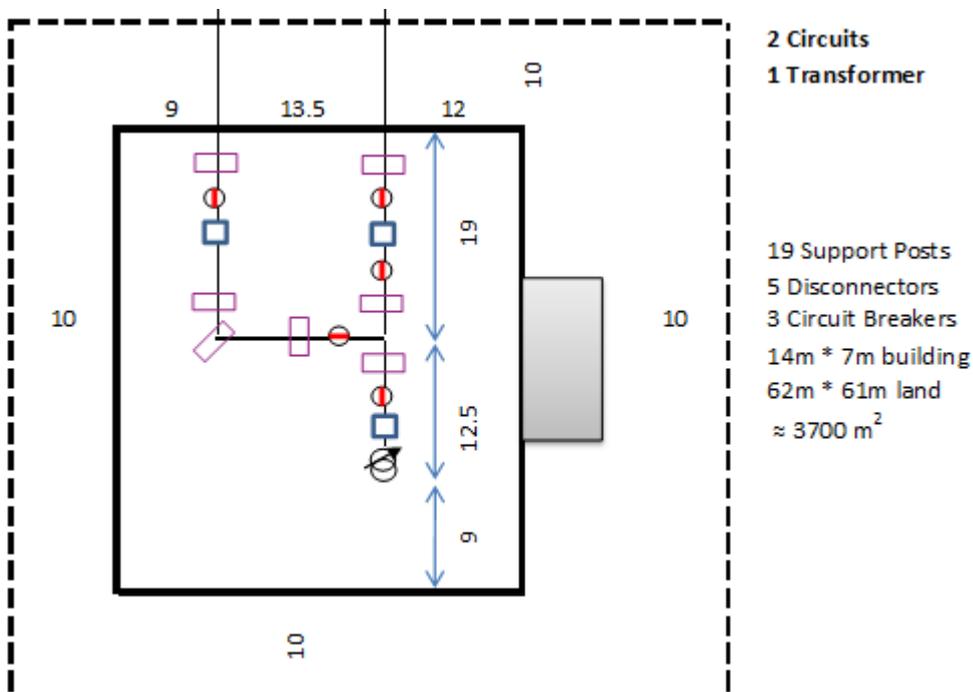
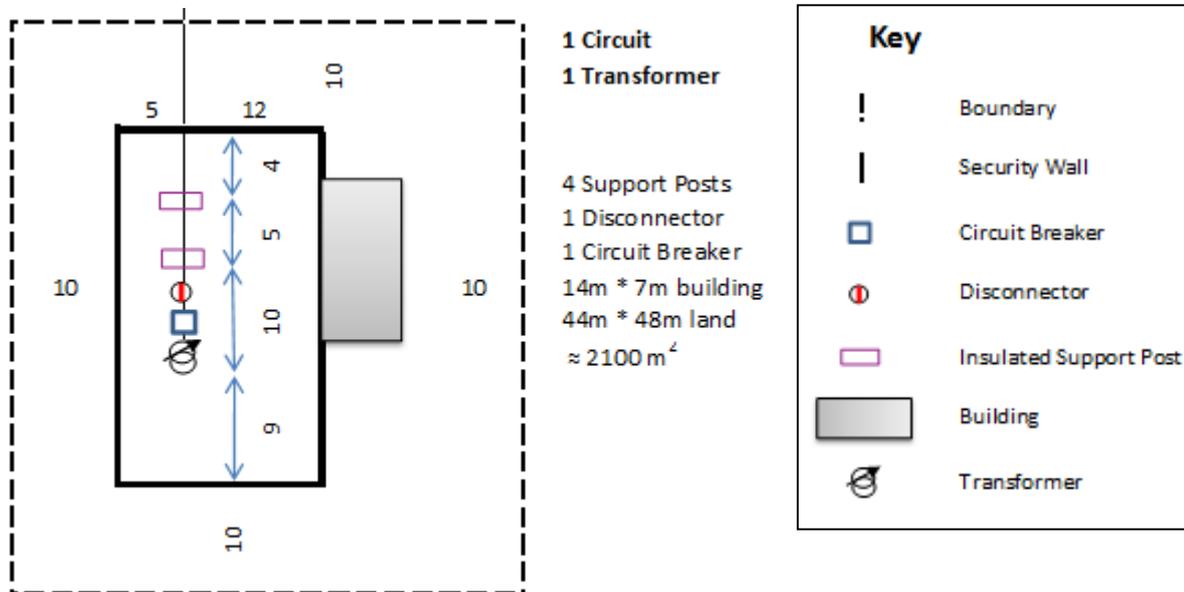
- Probability of a bus fault is 0.002 or once in 500 years. Likelihood is very low.
- Probability of a circuit breaker fault is 0.02 or once in 50 years.
- The more circuit breakers there are on a bus, the higher the probabilities of a CB fault occurring which will affect the bus.
- Adding a bus coupler also adds another CB increasing the probability of failure.
- Assumes the cost of a bus-coupler is \$360,000
- If a conventional bus failed without a bus-coupler (including CB failure), either of the two ABI's in the middle of the bus could be switched for half the site to be restored.
- The existing and proposed design of the 66kV subtransmission network means that the loss of two 66kV circuits for a bus fault will not effect the 66kV supply to surrounding substations. For sites with three or more 66kV circuits the economics of a bus coupler on a conventional bus need to be checked on a case by case basis.

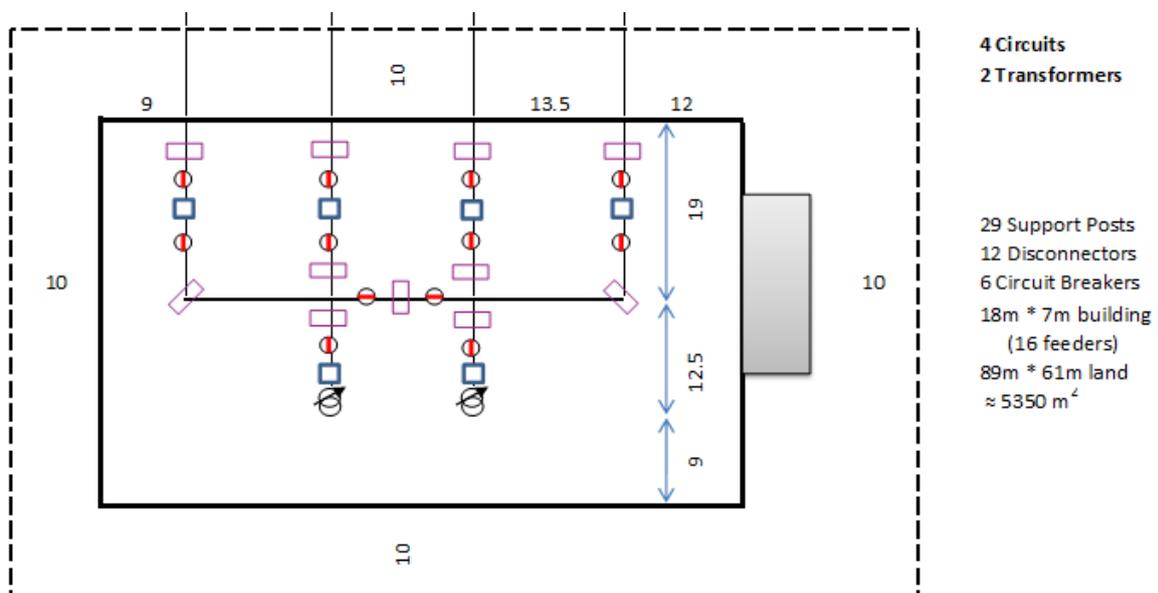
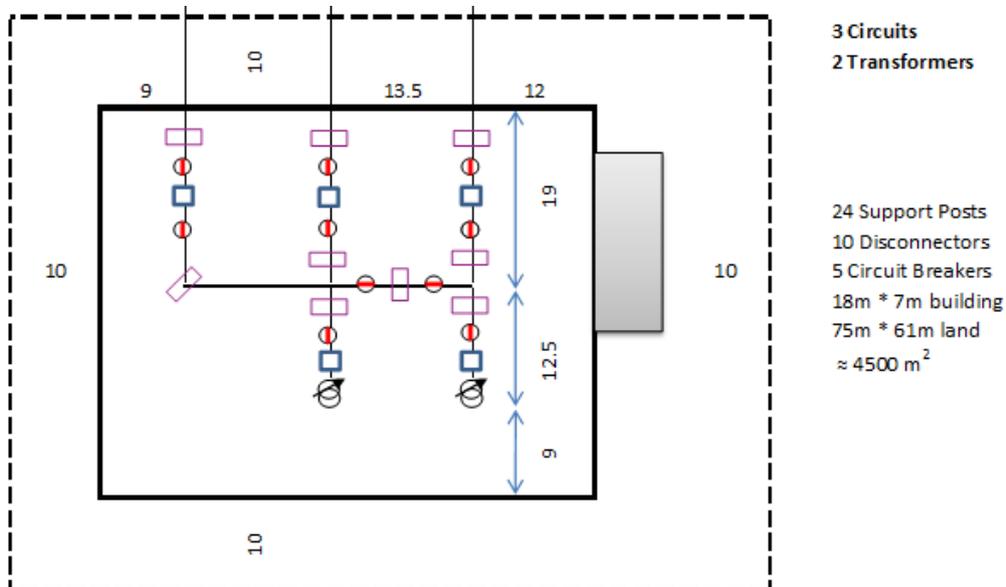
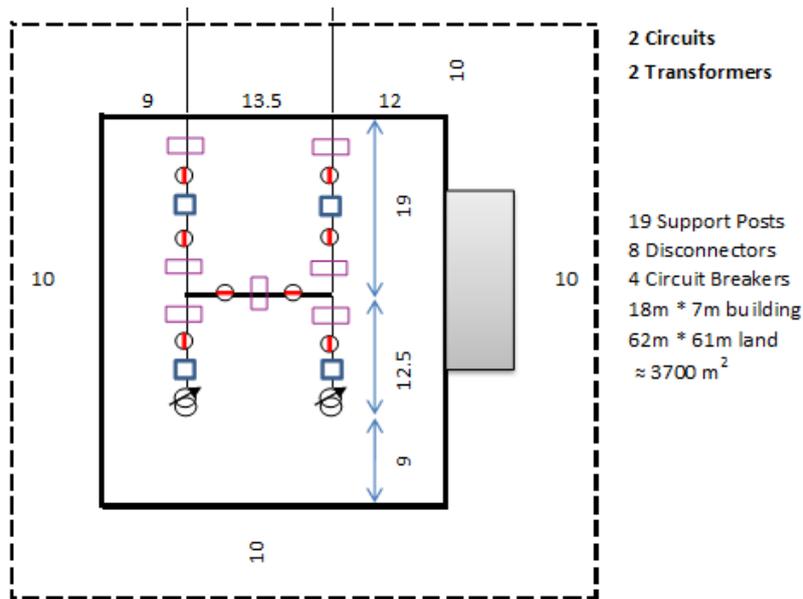
Summary:

- The gray column in the table above shows that for a CB probability of 0.02 it is not economic for a substation with 4 circuit breakers (2 circuits, 2 transformers) or 5 circuit breakers (3 circuits, 2 transformers) to have a bus-coupler installed.
- The economics are close to even with 6 circuit breakers (4 circuits, 2 transformers). However sensitivity analysis shows that is highly dependent on the CB failure probability. It becomes uneconomic if the fault rate moves from 0.02 to 0.018 (once in 50 years moves to once in 55 years).

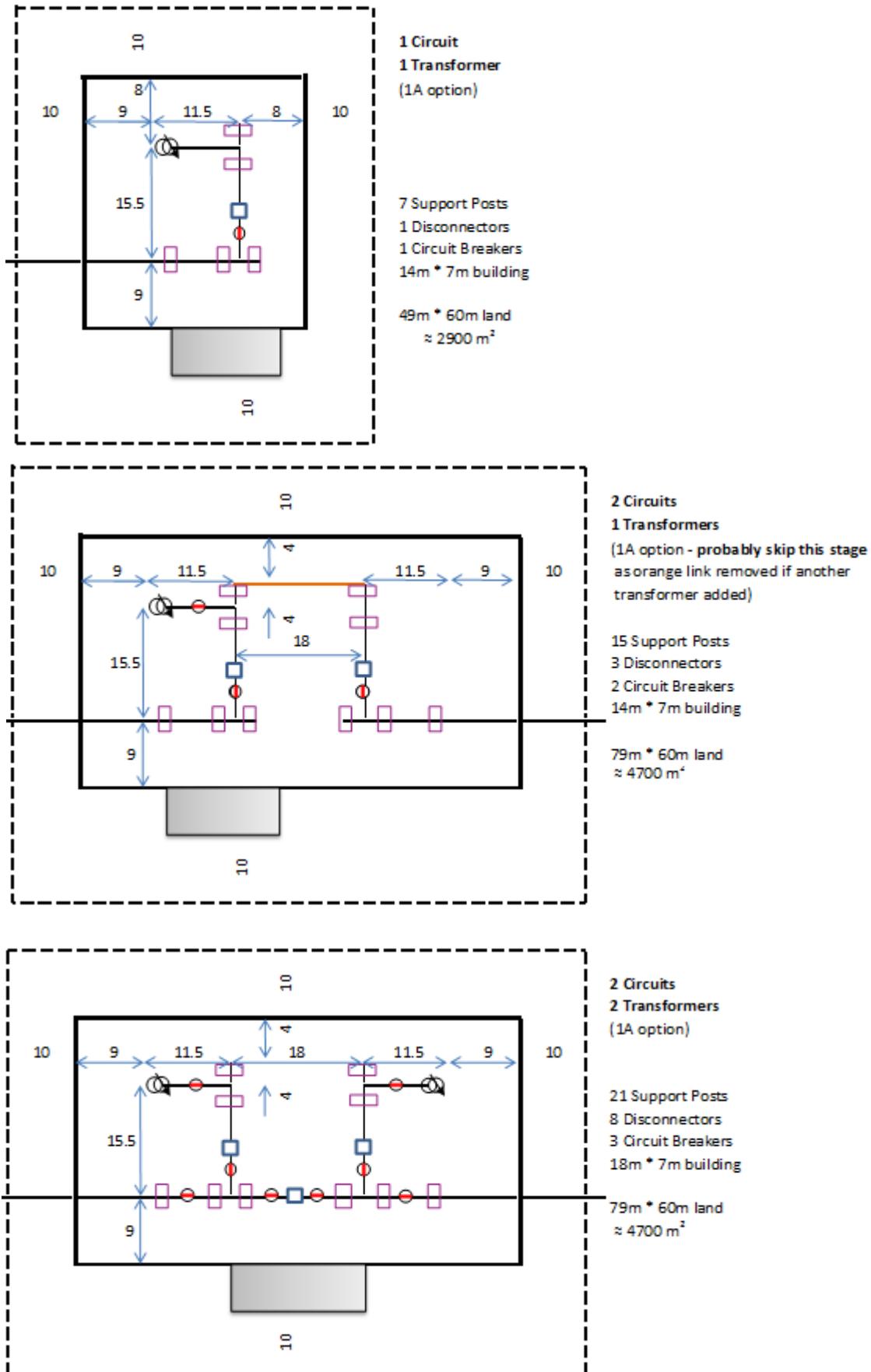
14 Appendix D Switchyard development options

Conventional Bus

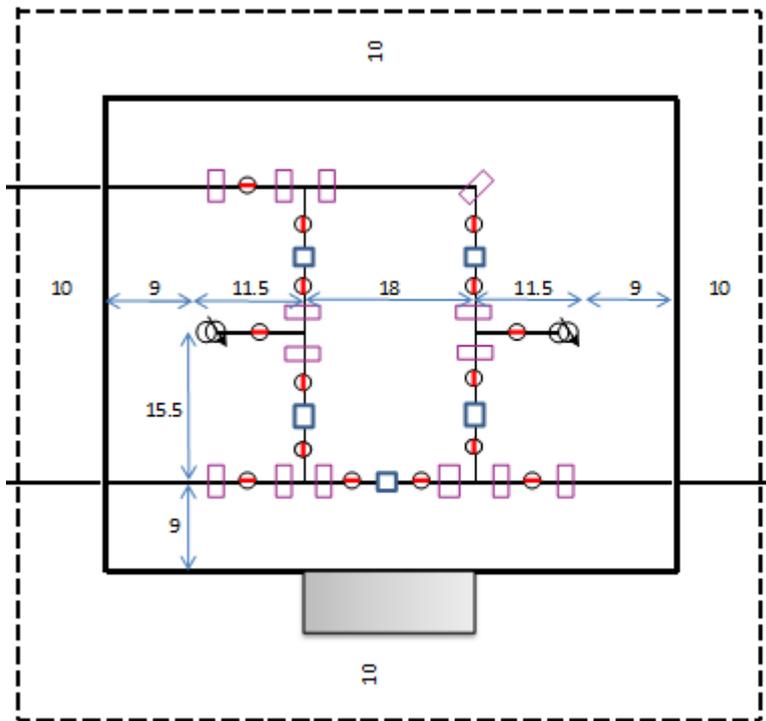




Ring Bus A (Transformers Opposite)

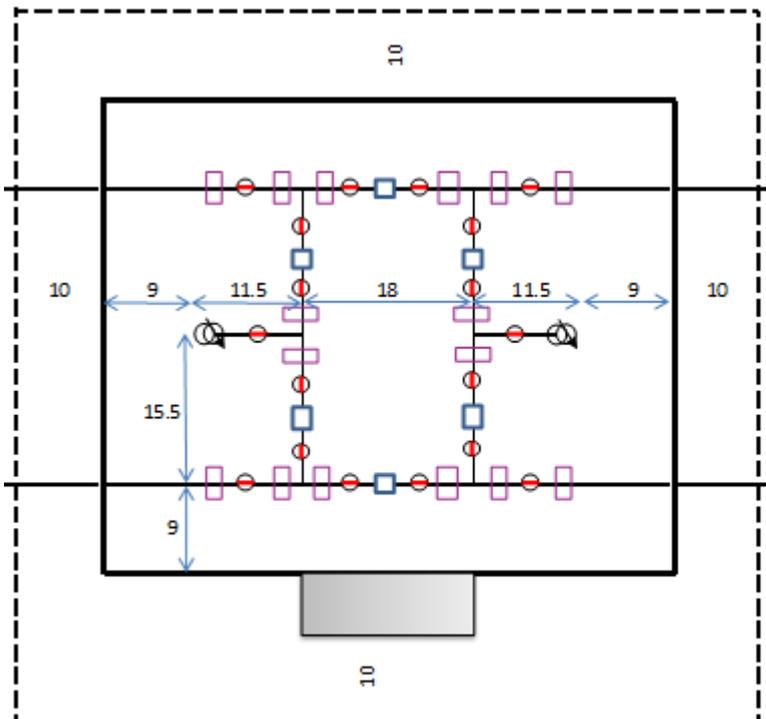


Ring Bus A (continued)



3 Circuits
2 Transformers

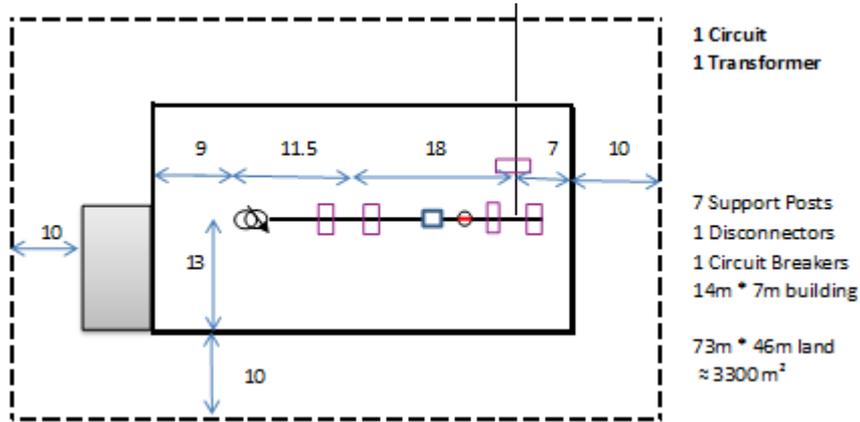
34 Support Posts
15 Disconnectors
5 Circuit Breakers
18m * 7m building
(16 feeders)
79m * 76m land
≈ 6000 m²



4 Circuits
2 Transformers

40 Support Posts
18 Disconnectors
6 Circuit Breakers
18m * 7m building
(16 feeders)
79m * 76m land
≈ 6000 m²

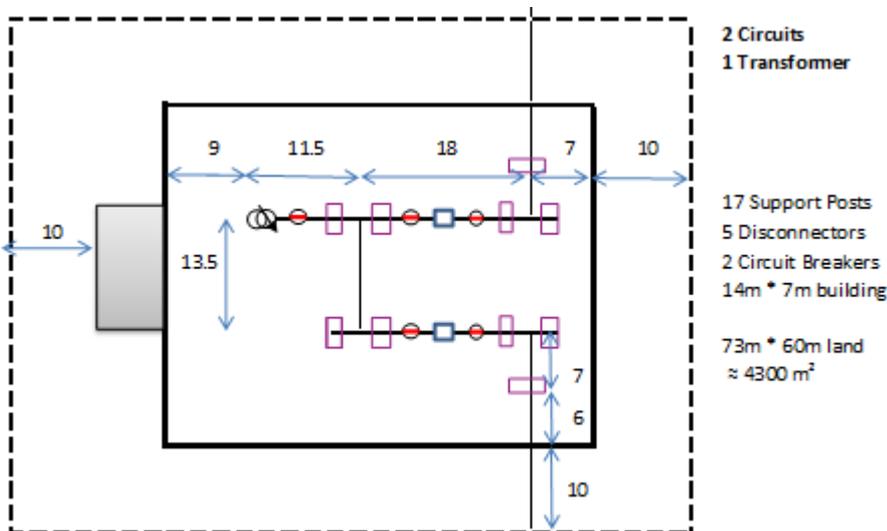
Ring Bus B (Transformers Adjacent)



1 Circuit
1 Transformer

7 Support Posts
1 Disconnectors
1 Circuit Breakers
14m * 7m building

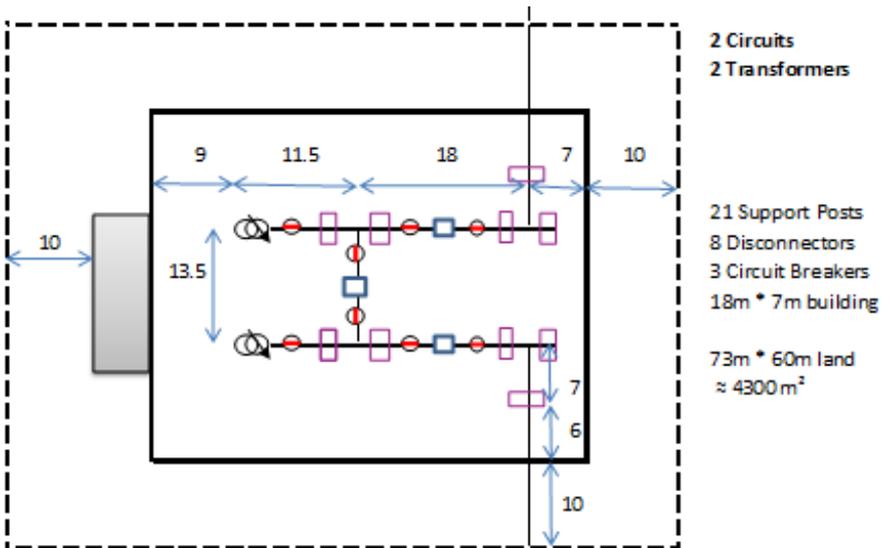
73m * 46m land
≈ 3300m²



2 Circuits
1 Transformer

17 Support Posts
5 Disconnectors
2 Circuit Breakers
14m * 7m building

73m * 60m land
≈ 4300 m²

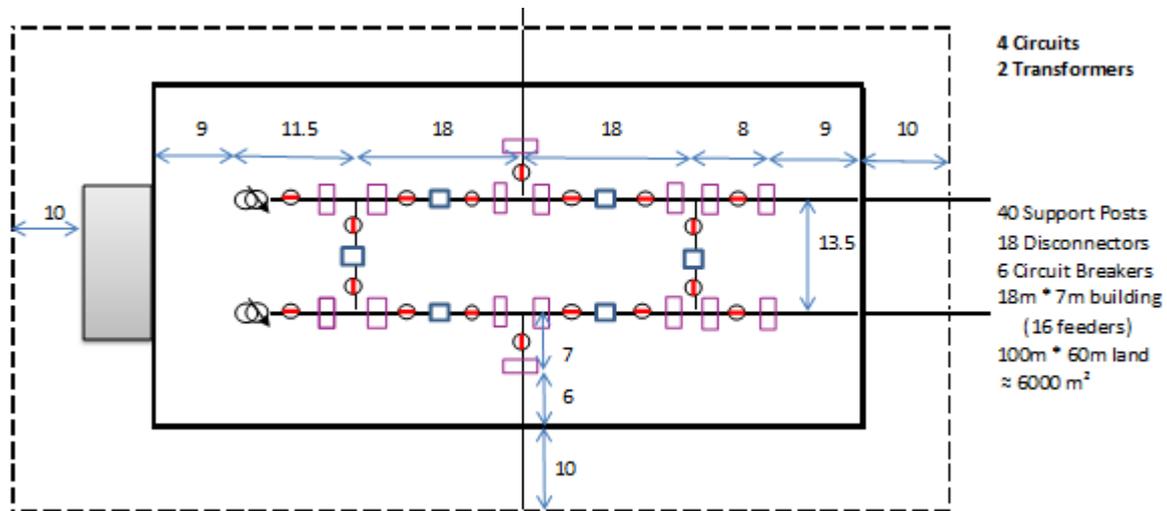
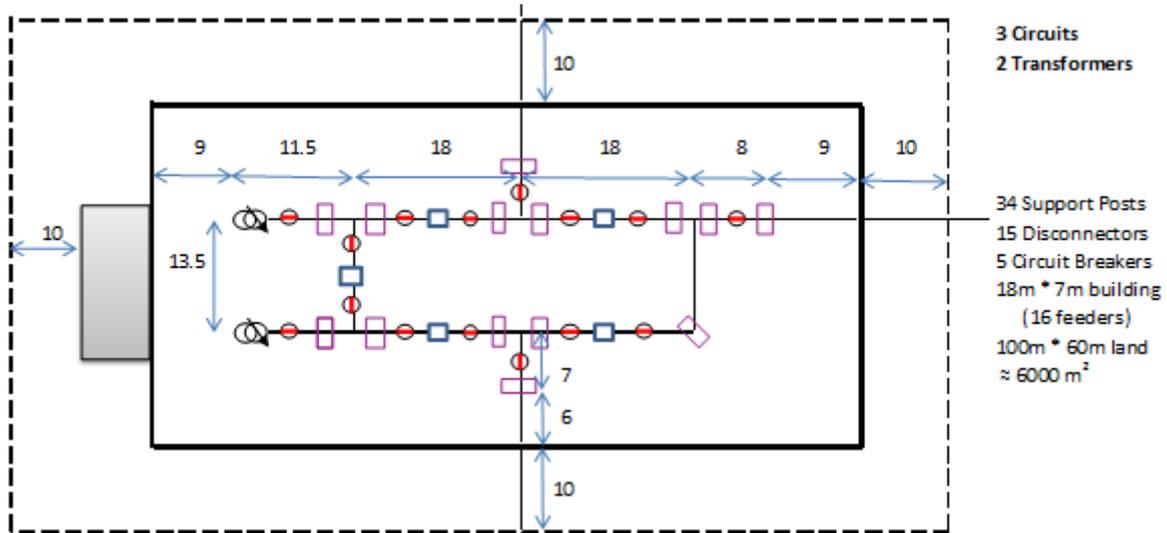


2 Circuits
2 Transformers

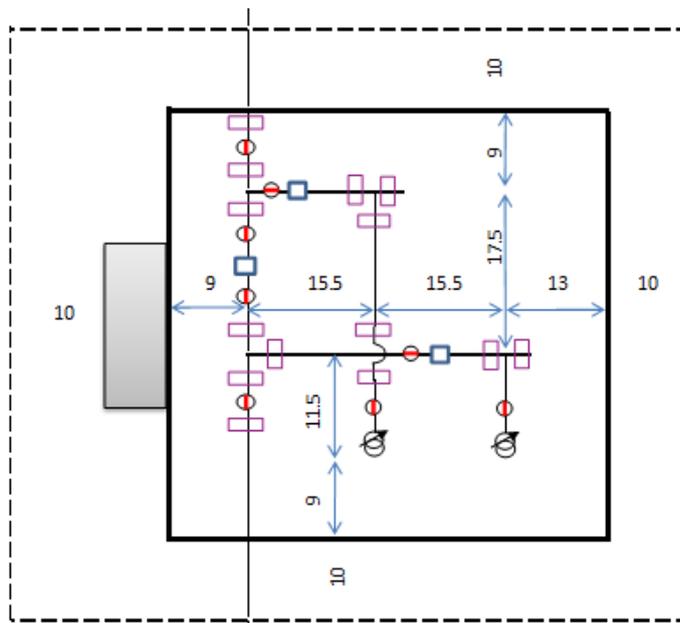
21 Support Posts
8 Disconnectors
3 Circuit Breakers
18m * 7m building

73m * 60m land
≈ 4300m²

Ring Bus B (continued)

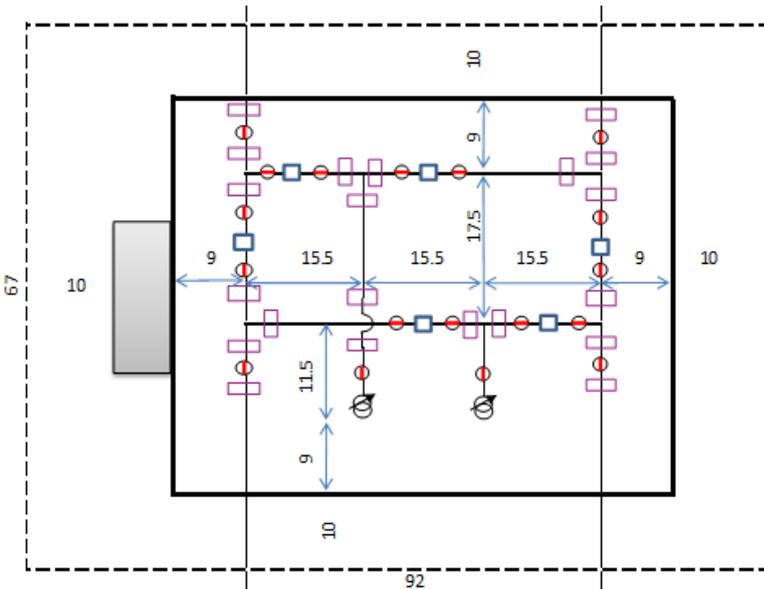


Ring Bus A (Transverse Bus)



2 Circuits
2 Transformers

25 Support Posts
8 Disconnectors
3 Circuit Breakers
18m * 7m building
(16 feeders)
80m * 67m land
≈ 5400 m²



4 Circuits
2 Transformers

45 Support Posts
18 Disconnectors
6 Circuit Breakers
18m * 7m building
(16 feeders)
92m * 67m land
≈ 6100 m²

Transverse bus option requires greater land area and requires extra isolation for work on transverse bus so not considered further.

Summary Comparison

Stage	Conventional	Ring Bus A	Ring Bus B
2 transformers, 2 circuits	4 Circuit Breakers 3700 m ² Land	3 Circuit Breakers 4700 m ² Land	3 Circuit Breakers 4300 m ² Land
2 transformers, 4 circuits	6 Circuit Breakers 5350 m ² Land	6 Circuit Breakers 6000 m ² Land	6 Circuit Breakers 6000 m ² Land

15 Appendix E Economic Analysis of bus configurations

Stage		Conventional	Ring Bus A	Ring Bus B
2 transformers,	CBs	4 \$ 212,000	3 \$ 159,000	3 \$ 159,000
	Land m2	3700 \$ 69,000	4700 \$ 88,000	4300 \$ 81,000
	2 circuits VOLL	\$ 44,000	\$ 11,000	\$ 11,000
	Annual Total	\$ 325,000	\$ 258,000	\$ 251,000
2 transformers,	CBs	5 \$ 265,000	5 \$ 265,000	5 \$ 265,000
	Land m2	4500 \$ 84,000	6000 \$ 112,000	6000 \$ 112,000
	3 circuits VOLL	\$ 55,000	\$ -	\$ 11,000
	Annual Total	\$ 404,000	\$ 377,000	\$ 388,000
2 transformers,	CBs	6 \$ 318,000	6 \$ 318,000	6 \$ 318,000
	Land m2	5350 \$ 100,000	6000 \$ 112,000	6000 \$ 112,000
	4 circuits VOLL	\$ 66,000	\$ -	\$ 11,000
	Annual Total	\$ 484,000	\$ 430,000	\$ 441,000

Can be worse than this as lose ability to feed through to adjacent substation for a transformer fault.

Conventional - In all stages, failure of transformer CB can trip CB on adjacent transformer, cutting off all local load.

Ring Bus A - For 2 circuits, failure of middle CB trips CBs to transformers, cutting off all local load.

Ring Bus B - In all stages, failure of CB between transformers can trip CBs to both transformers, cutting off all local load.

Circuit & transformer failures do not cut off load for any of these options.

Bus fault probability of 0.002 means its contribution to VOLL is insignificant

Land cost varies from \$50k to \$700k for 4700 m2

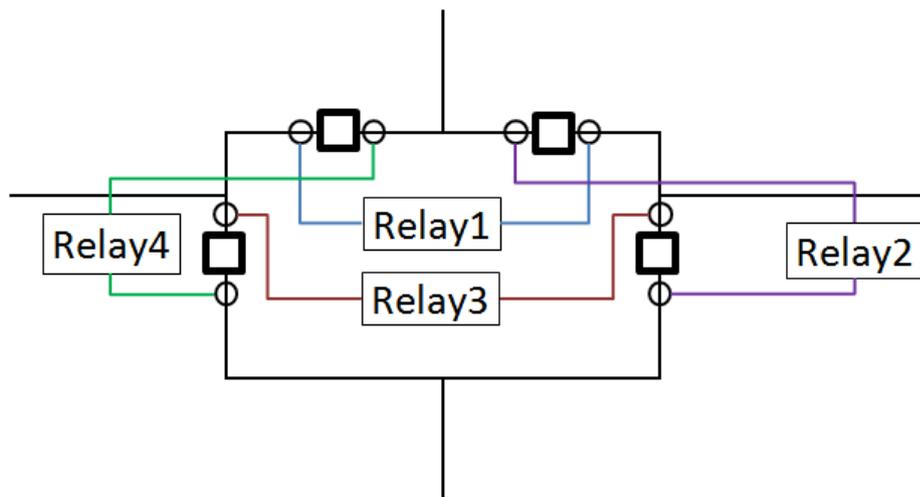
(ref \\Verdi\Groups\Network Development\Network planning\Architecture review 2011\111123 Model Inputs.xlsx, sheet "Costs")

Land value used	\$ 500,000	for	4700 m2
Land improvements	\$ 100,000		
Annualised Land + improvements	\$ 88,000		
CB cost	\$ 361,000		
Annualised CB cost	\$ 53,000		
Annual Capital, Maintenance and Operations recovery factor	14.6%		
Peak demand (kW)	40000		
Load factor	0.6		
Disconnecter switching time to restore from CB fault	1		
VOLL (\$/kWh)	23		
Probability of CB failure	0.02		

16 Appendix F Bus Protection

Busbar Protection – Ring Bus

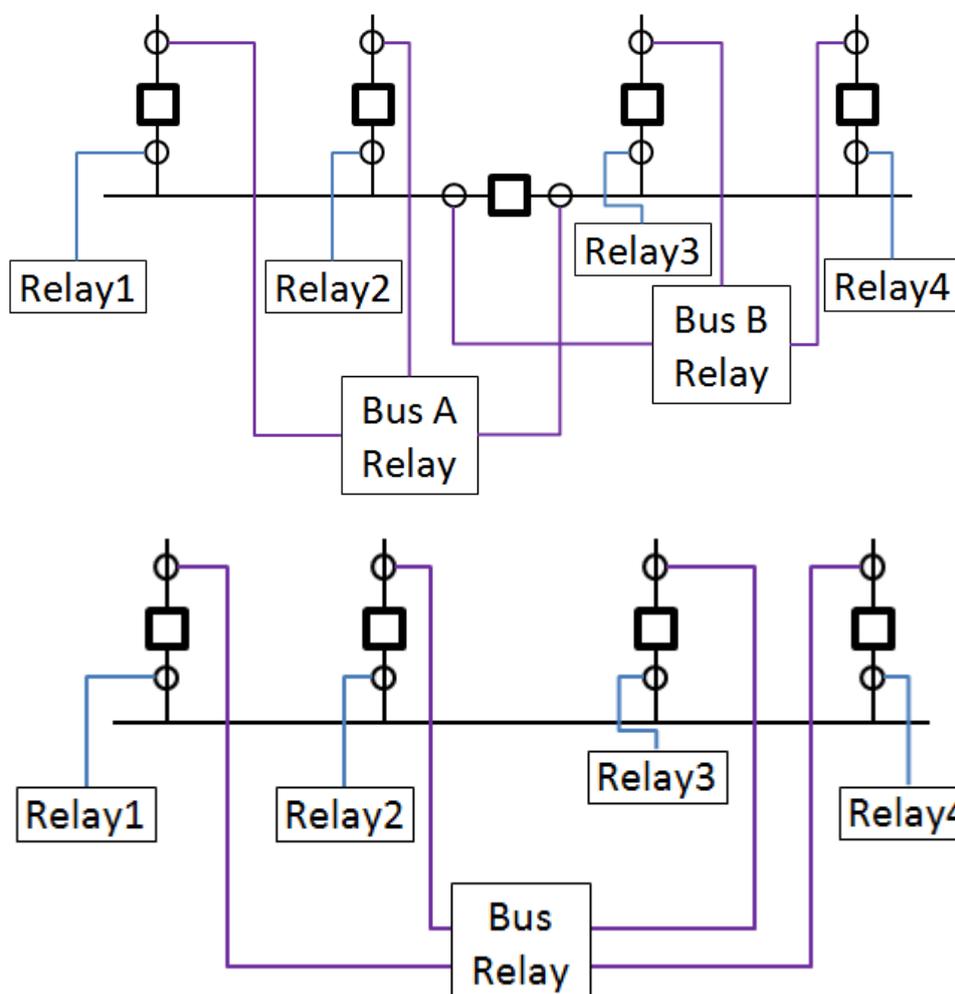
One of the advantages of a ring bus design is that for each feeder, 2 CT's are used and these overlap the adjacent feeder. The dead-tank circuit breakers provide CT's on both sides so that the furthest side from the feeder can be used for 2 adjacent feeders creating the overlap. Typically Orion use line differential protection on sub-transmission circuits so that each section of the ring bus is protected by overlapping differential zones using multiple relays i.e. 1 zone per feeder. Differential or distance protection would operate quickly to clear faults in zone.



If the primary protection on a circuit fails, backup over-current protection would operate via the protection at the far end and then the 2 adjacent relays. For bigger schemes backup protection can be provided via duplicate relays.

Busbar Protection – Conventional Bus

Two diagrams are shown below. One with a bus coupler and one without.



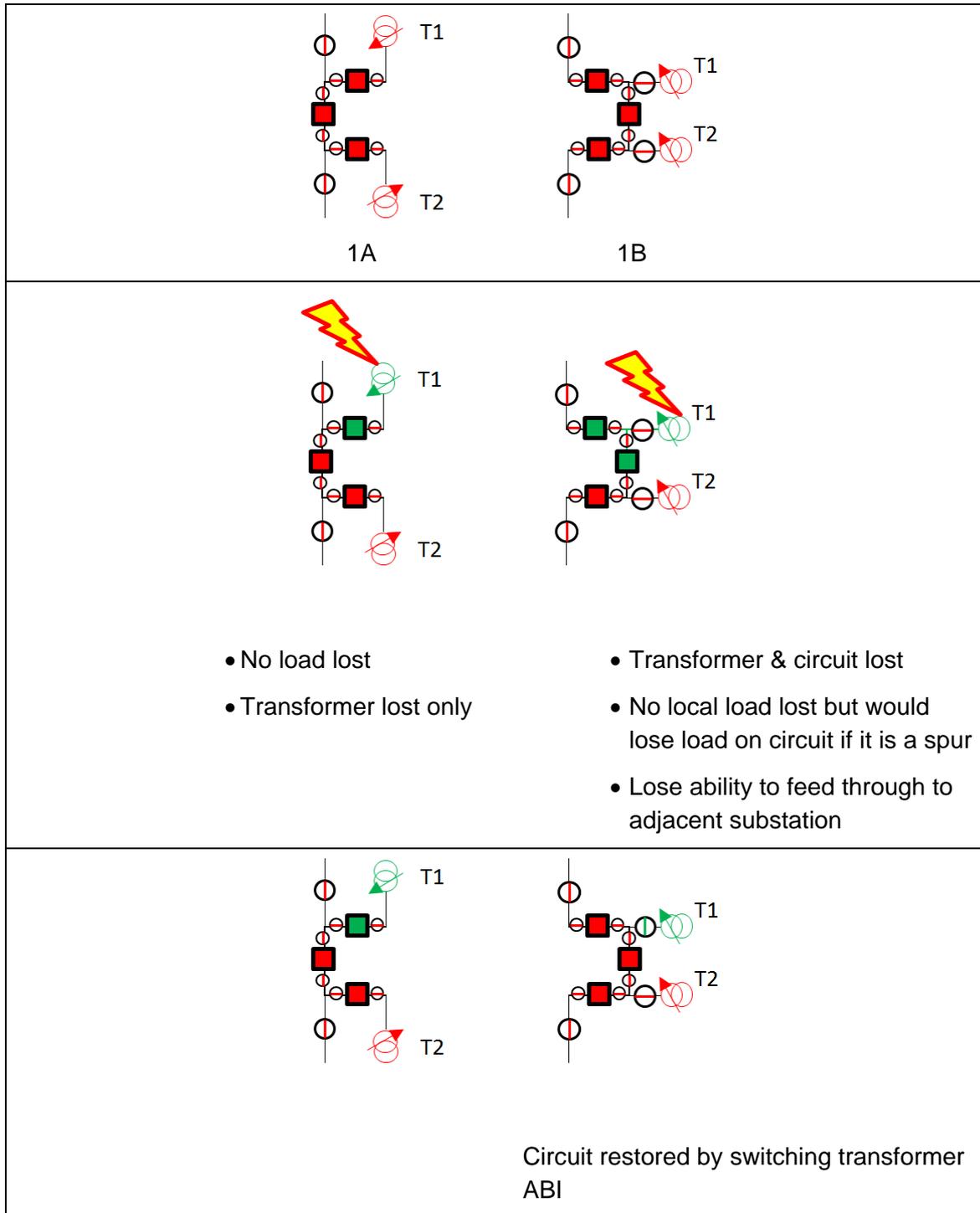
Historically bus protection was achieved using High Impedance Differential relays. The CT's from each phase are connected together in parallel. Resistors and MOV's are used to provide security against mal-operation from CT saturation. All CT's are required to be the same type and ratio. Bigger schemes typically have 1 relay for each bus and an additional relay covering all busses as an overall bus check. Both the local and overall bus relay must operate together for the circuit breakers to trip. To take a circuit out of service for testing, the CT's for the circuit must be shorted out.

With the advent of modern multifunction relays the typical approach is to use a differential bus relay. The main difference is each individual CT is wired to the relay. Relays of this type generally allow for up to 18 CT's or 6 circuits. Multiple relays can be ganged together for larger schemes. The big advantage with this scheme over the high impedance is that every set of CT's can be different, the stability is better and they are easier to alter at a later date. The bus relay can also provide backup over-current protection for the each circuit. A circuit can be taken out of service for testing internally using the logic settings of the relay. Orion uses this type of protection for its 11 kV zone substations.

Both conventional bus schemes would be more expensive than a ring bus. However if backup protection was required then they might be closer in cost.

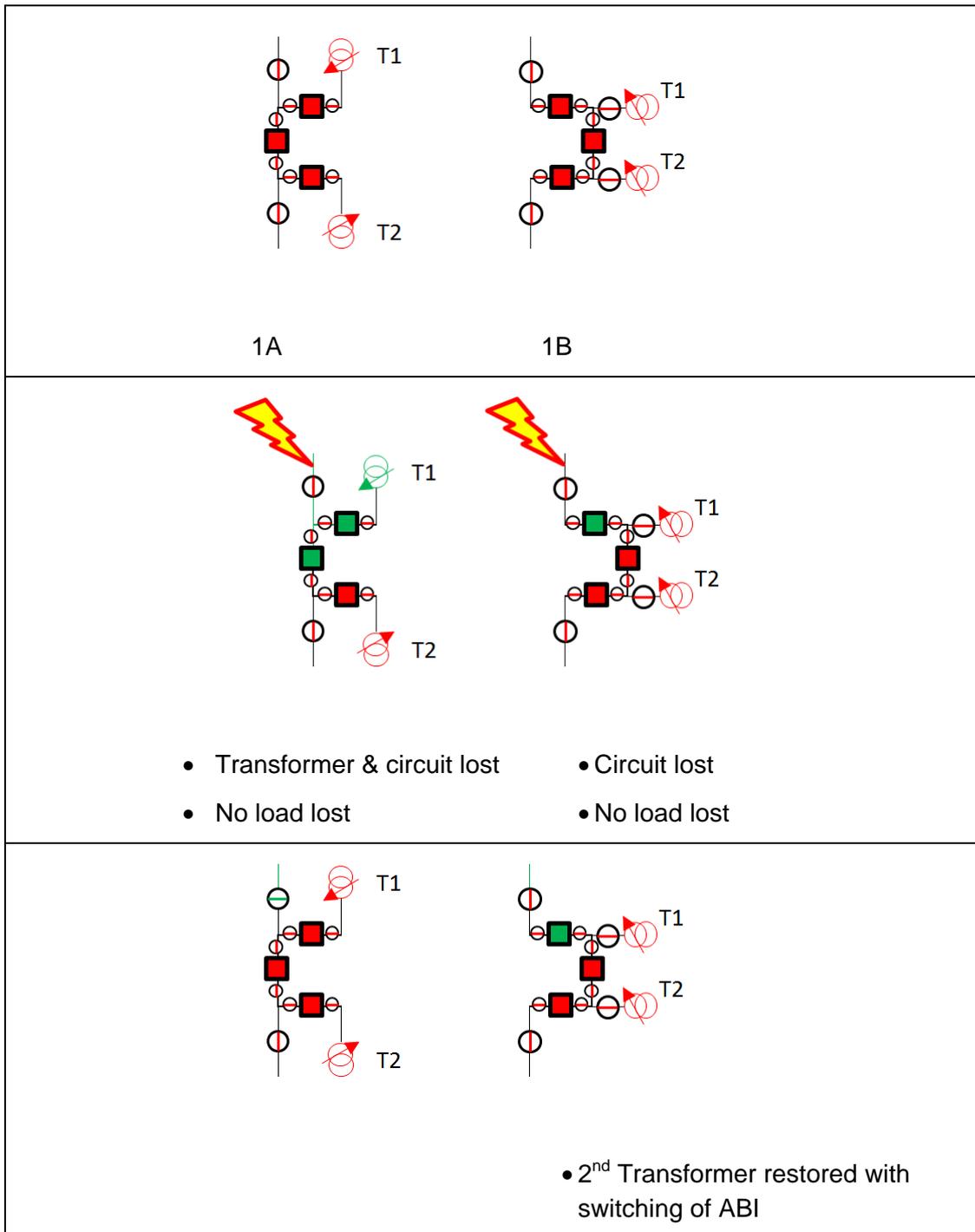
17 Appendix G Comparison of Ring Layout Options 1A & 1B for Network Faults

Transformer Fault



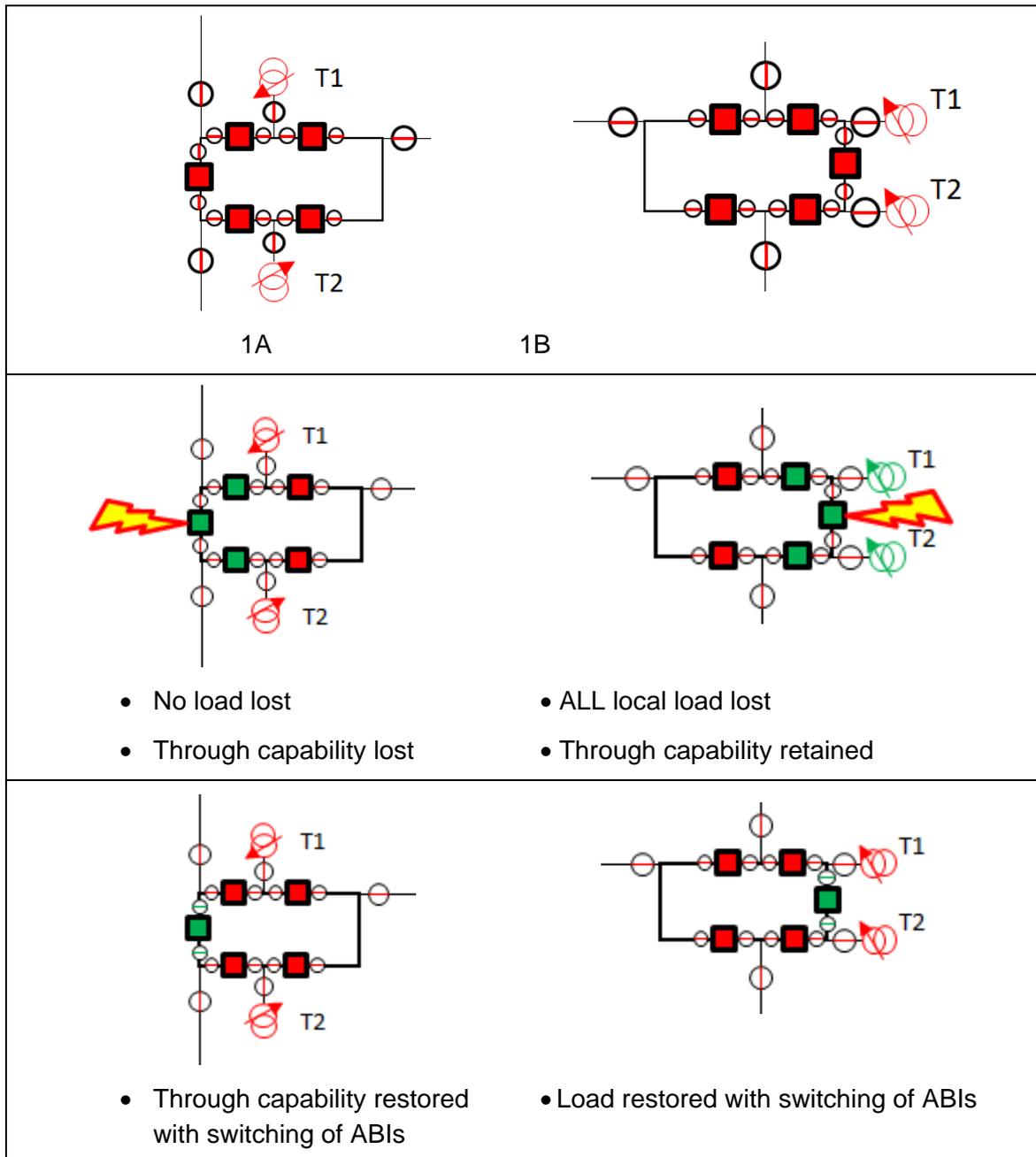
Option 1B therefore gives lower performance for a transformer fault, until the transformer ABI is switched to take the faulted transformer out of service. Depending on the how the substation is configured within the overall network, the loss of ability to feed through to an adjacent station can reduce network resilience to multiple faults.

Circuit Fault



Both Ring Bus 1A and 1B options give effectively the same performance for a circuit fault.

Circuit Breaker fault

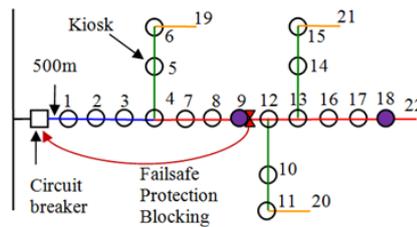
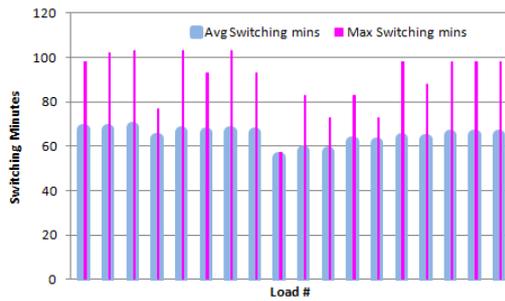
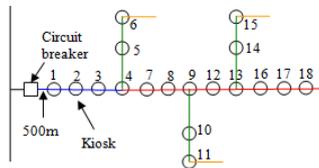


The impact of losing through capability depends on interconnections with neighbouring substations. Ring Bus 1B option is considered to have weaker fault performance as it is vulnerable to losing all local load for a circuit breaker fault (regardless of interconnections with neighbouring substations).

Appendix 7

11kV urban network architecture review

Urban 11 kV Network Architecture Review



...

Draft: 28 September 2012

NW 70.60.06

Table of Contents

Executive Summary	3
Process	4
Key Findings for Greenfields	10
Recommendations	11
Appendix A Model & Inputs	12
Appendix B Ring Main Unit Paper for 11kV Architecture review	17
1.1 Background	18
1.2 Arc Flash	18
1.3 Use of the Magnefix Switching Units in our 11kV architecture	19
1.4 Conclusion.....	20

Executive Summary

In view of the unprecedented investment by Orion in new and replacement assets over the next 50 years, due to:

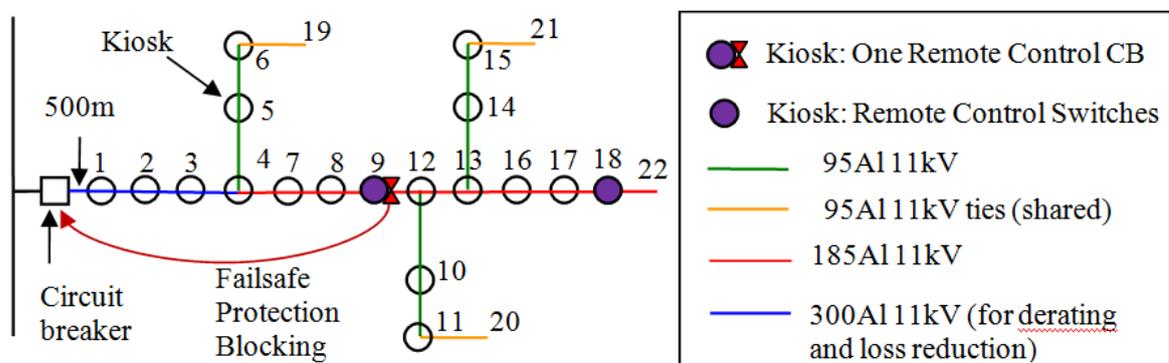
- earthquake damaged assets
- changes in load due to post-earthquake reconstruction and relocation
- projected load growth in the western urban regions, independent of earthquake effects

it is appropriate to review the network design principles. The subtransmission topologies have been examined and this report is the next step in that process and covers 11 kV configurations. To conclude this process it is proposed that the 400 V system will be assessed and then the subtransmission and 11 kV reports will be reviewed in light of this.

It is recommended that the current radial architecture continues to be used as the design for urban feeders. Twelve of these feeders deliver electricity from a 40 MW zone substation to serve ~12,000 customers. The recommended cable design gives capacity to transfer load between zone substations should one zone substation be out of service ie supports N-2 at subtransmission level.

The use of intermediate circuit breakers, Remote Indication from kiosks, and kiosks with Remote Control & Indication was considered. The latter two give better options for future development as technology is developed which facilitates improved customer service. A decision to change to a new type of 11 kV RMU switchgear now requires a trial to confirm the as built costs for kiosks. This will enable refinement of the analysis to give the best permutation of Remote Indication and Control functionality.

Current information shows the best configuration is:



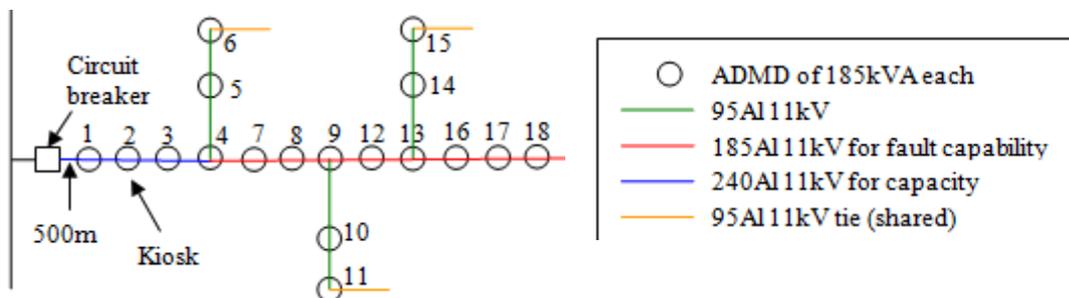
The kiosks shown with Remote Control also have Remote Indication. The addition of Remote Indication only to a number of the other kiosks will be reviewed as part of the 400V architecture review to be carried out next.

Process

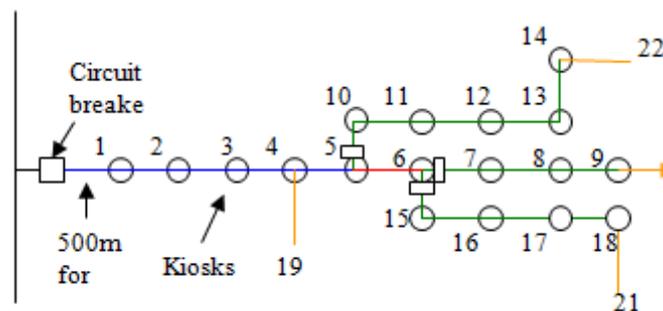
The Orion 2007 Security Standard review recommended the introduction of a radial 11 kV architecture design with N-2 subtransmission capability. That is, the 11 kV feeder cables shall be configured and have capacity to provide restoration of power for a complete failure (N-2) of a zone substation. The current review builds on that piece of work to include consideration of 11 kV losses, capacitance, safety, latest pricing and reliability data, and considers the use of remote control and/or monitoring.

The 2007 architecture review included an economic assessment of many different 11kV networks. It was not considered necessary to revisit the economics of all the 2007 architecture options. A review of the 2007 work concluded that an update of the economic analysis for the following 4 layouts would provide sufficient results for us to conclude whether our current practice is still appropriate and what refinements would deliver additional benefit. Each option assumes the use of a 40 MW zone substation with each kiosk placed at 300m intervals unless otherwise stated.

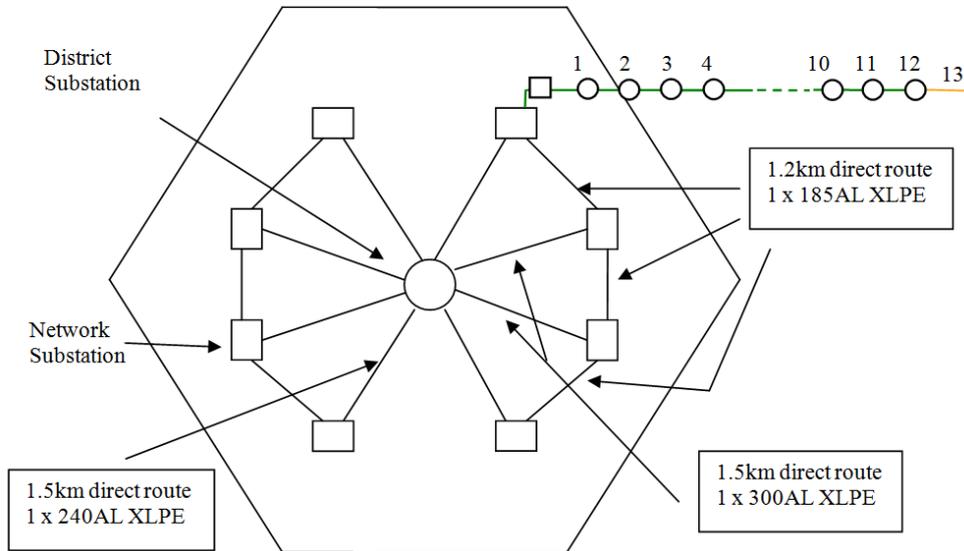
- Option 1: 12 feeders N-2 Inter zone substation capacity (current Orion practice for new build).



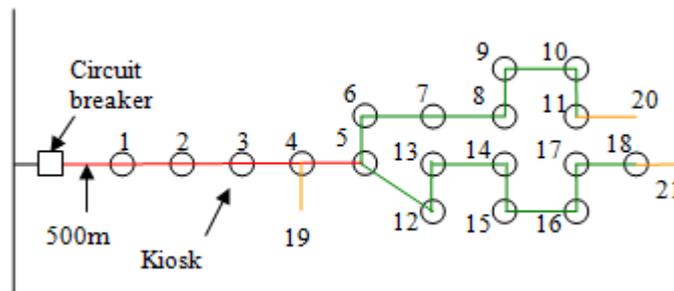
- Option 2: 12 feeders N-2 inter zone substation capacity with 3 intermediate circuit breakers (minimising outage costs by reducing number of customers losing supply for a fault on the feeder).



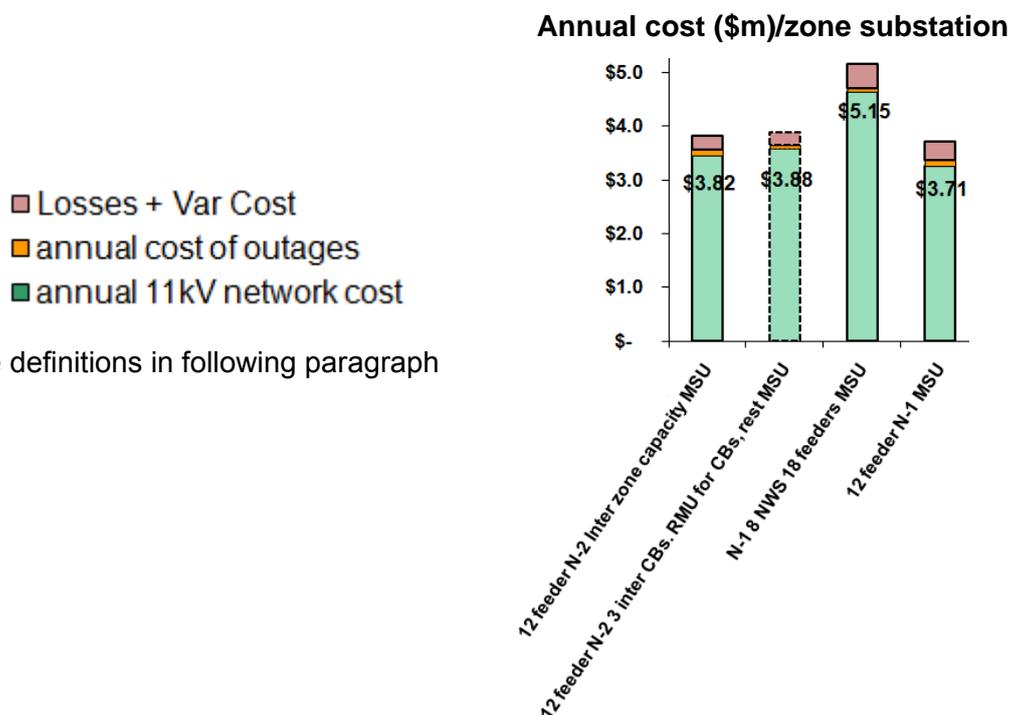
- Option 3: A primary ring architecture with 8 Network Substations (NWS) and 18 secondary feeders. This design does not provide N-2 inter zone substation capacity but is similar to the 11kV network architecture used by Orion prior to the 2007 architecture review.



- Option 4: 12 feeders N-1 inter zone substation capacity (to assess the difference between N-2 and N-1)



The analysis showed the following results (Appendix A gives the inputs for this assessment):



The annual 11kV network cost is the total cost of providing the 11kV network including the required return on capital, administration, maintenance and operations over the expected life of the assets. The annual cost of outages represents the estimated economic cost of outages to our customers. This cost is calculated by adding the Value Of Interruption (VOI- \$/kW interrupted) and the Value Of Lost Load (VOLL - \$/kWh interrupted). The load and duration used to determine VOI and VOLL was calculated by considering the probability and impact of each 11 kV cable and feeder CB fault on each kiosk on the feeder.

The loss cost is dependent on the length and size of cable and the amount of load distributed on each cable section. Energy losses are calculated by multiplying peak losses by a load loss factor and a \$/kWh value. The reduction of losses at peak also has a value to the transmission and generation sector of the electricity industry. We assume that peak load loss reduction has a per annum value of \$91/kW transmission¹ and \$125/kW generation².

The Var cost is calculated by multiplying the peak MVar consumption by a \$/MVar value³. This approach is in line with proposed changes to the Transpower Transmission Pricing Methodology (TPM) which is to include a \$/MVar charge at regional transmission peak.

Option 3 - the **Network Substation**/primary ring design - has a significantly higher capital cost due to the extra cost of cable and CBs (ie much longer green bar) and the benefits of this design for decreasing outage costs are an order of magnitude smaller (the reduction in height of the orange bar). This layout has the benefit of reducing the operations costs of planned outages, but this would need to exceed \$1M/zone substation per year before it would be a competitive option – this is clearly not the case.

The graph shows that all three radial options (1, 2 and 4) are relatively similar in overall cost. Although option 4 has a slightly lower total cost than option 1, it is fundamentally a weaker network design and does not provide:

- the strong 11kV network connections between zone substations of option 1&2 to provide for planned and unplanned 11kV ripple plant shutdowns.
- the same level of resiliency for zone substation shutdowns – the economic cost of N-2 zone substation shutdowns is included in the analysis for each architecture but the benefit of the inherent extra capacity in the option 1&2 design is not captured for other rare but severe events that involve more than just one zone substation failure.
- the same level of spare capacity as option 1&2 to shift open points for unexpected load growth or defer new subtransmission investment in the short term

For the above reasons, option 3 & 4 were discarded from further analysis. Further analysis is focussed on refining options 1&2.

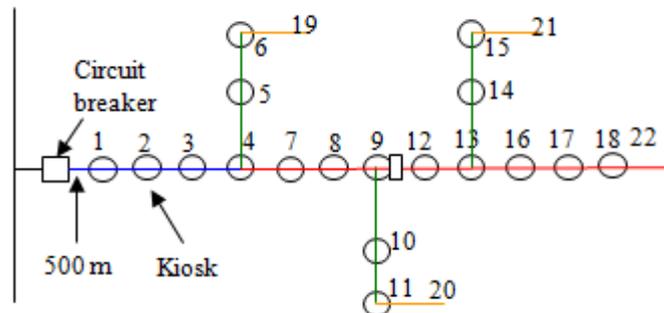
Comparing the first two options shows that introducing three intermediate circuit breakers gives a reduction in the outage cost. However it is very difficult to implement in practise. Subdivision enquiries from developers tend to be staged with changes in roading design occurring and poor coordination with other developers/developments in the area. These

¹ Transpower interconnection charge

² [\\Verdi\Groups\\$\Network Development\Network planning\Demand Side Management\Presentations and Reports\111010 Demand Side Management Stage 2.pdf](\\Verdi\Groups$\Network Development\Network planning\Demand Side Management\Presentations and Reports\111010 Demand Side Management Stage 2.pdf)

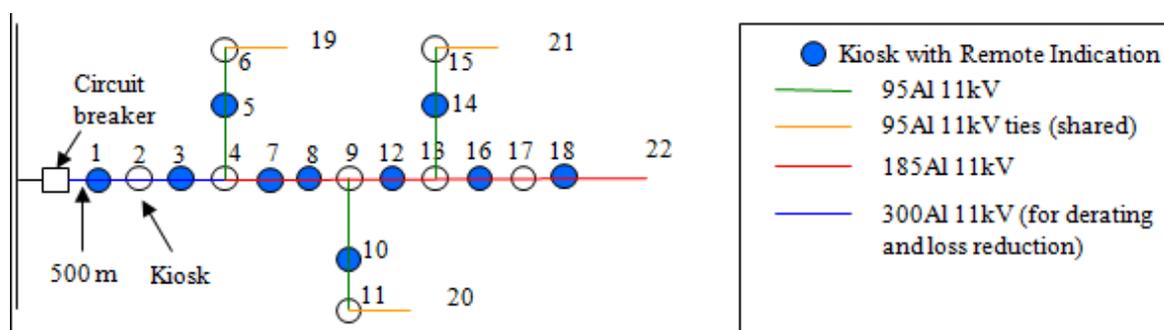
³ [\\Verdi\Groups\\$\Network Development\Network planning\Demand Side Management\Presentations and Reports\110824 Demand Side Management review Stage 1.pdf](\\Verdi\Groups$\Network Development\Network planning\Demand Side Management\Presentations and Reports\110824 Demand Side Management review Stage 1.pdf)

practical issues make the placement of the three limbs and associated circuit breakers difficult on a regular basis. The reduction in outage costs by using intermediate breakers to reduce the number of customers losing power for an 11 kV fault is desirable. Therefore a 5th configuration was considered with just one intermediate breaker as shown in the diagram below.



This gave an increase in total annual cost (2%, \$87k/yr/zone substation), but with the benefit of improved SAIDI (12 minutes → 9 minutes) and SAIFI values (0.19 → 0.14) for the 11 kV components. As with all intermediate circuit breaker options, this configuration introduces a potential issue with ensuring reliable discrimination (with fast clearance times for safety and power quality) between the zone substation feeder breaker and the intermediate breaker. This may be addressed by adding communications (eg pilot cable) to enable blocking of feeder breaker protection when the intermediate breaker intends to clear the fault.

To further reduce the outage cost, **remote indication** was added to the original option 1 (Inter zone capacity No intermediate breaker configuration):



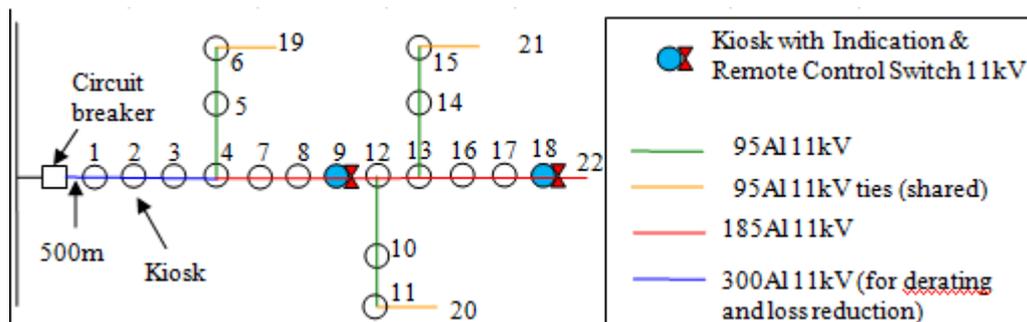
This enables quicker fault location and eliminates unnecessary temporary switching (which is used to get lots of customers back on sooner whilst fault locating continues). The cost is slightly higher (0.2%, \$9k/yr/zone substation), but with significantly less outage time for the last customer to be restored (~100 mins → ~60 mins).

The option analysed in detail used remote indication at every 2nd kiosk which enables an Operator to be sent directly to a kiosk that is at one end of the faulted cable. The number of indicating kiosks could be reduced from the option shown here to reduce capital cost, however this would be small (~\$130/kiosk/yr), and the outage cost would increase. Having remote indicators at every 2nd site has the advantage of minimising the outage cost regardless of multiple faults ie most resilient option. Trying to reduce the number of remote indicating sites leaves the feeder vulnerable to a sub optimum configuration of indicating sites when a fault has led to it being supplied from a neighbouring feeder.

Remote indication also provides other benefits - power quality monitoring, metering information including maximum demand and time of use and real time monitoring such as

kiosk door security switches. These other benefits are to be quantified as part of a review of our low voltage network architecture.

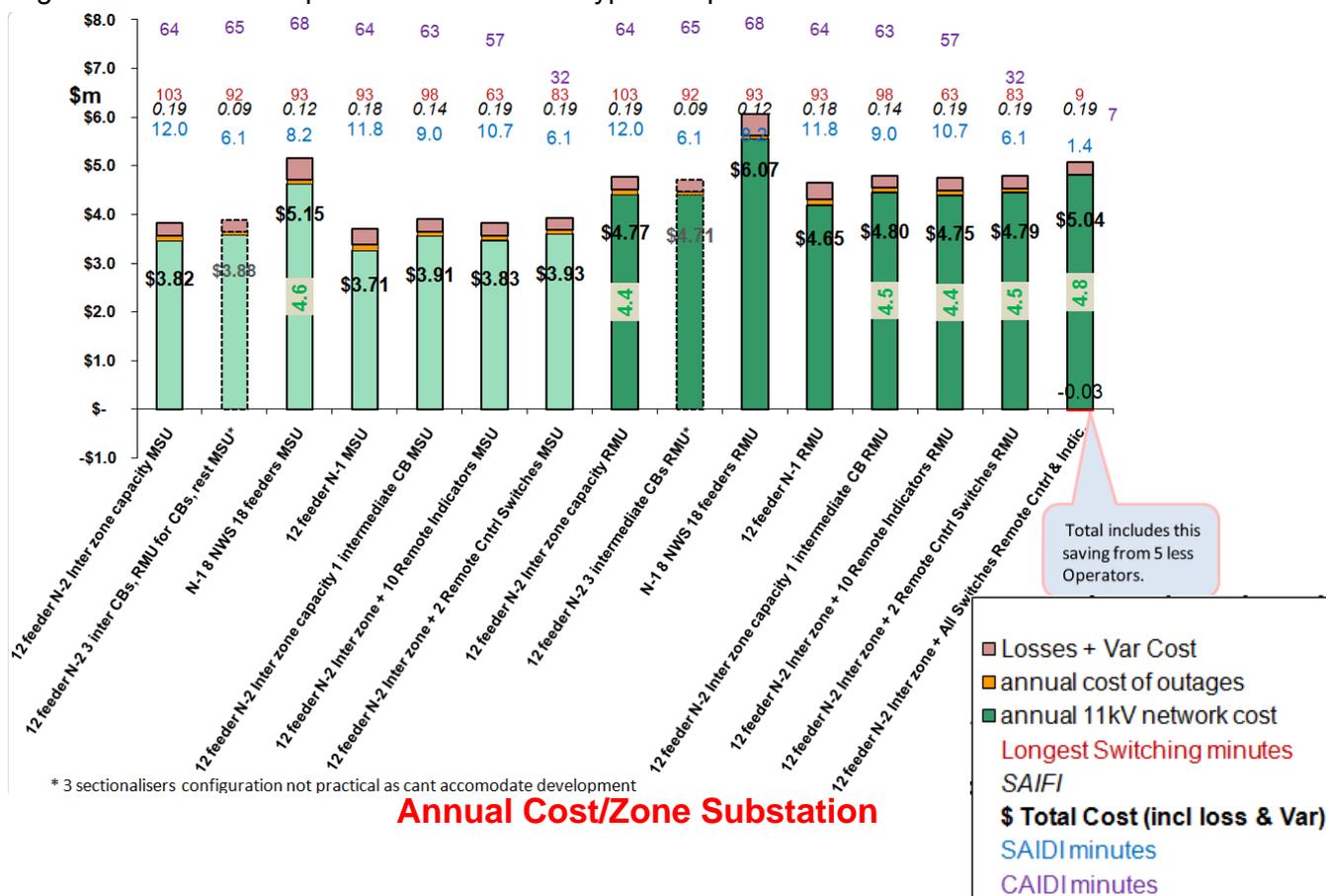
Another way to reduce outage times is to have **Remote Control & Indication** to save travelling time (the single largest delay in power restoration switching). The lowest cost addition of remote control is two kiosks as shown in the following diagram.



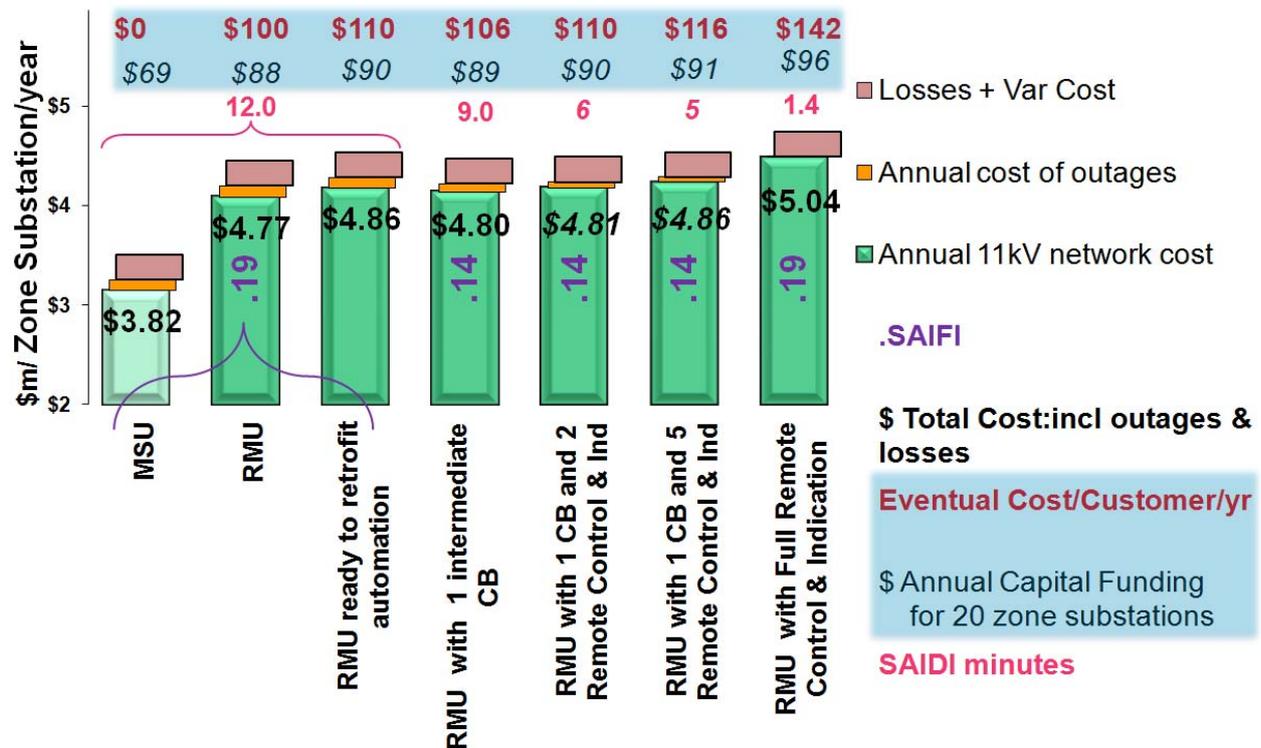
This enables half the kiosks to be restored remotely giving a significant decrease in Customer Average Interruption Duration Index (CAIDI) minutes from over 63 to under 33.

At this point, a report was received recommending that new 11 kV switchgear should not be based on the Magnefix MSU (Appendix B). Alternatives are significantly more expensive, so the analysis was extended to show the implications for all the options considered for this review.

The results are shown below, with light green for the options using Magnefix MSU, and dark green for the same options but with a new type of replacement RMU.



A workshop of Orion staff took the recommendation to cease using MSUs and agreed to focus on permutations using a new RMU, with an intermediate circuit breaker, and a number of kiosks having remote control & indication. The results of this are shown in the next picture.



In August the Corporate Group accepted the proposed change from Magnefix MSU → RMU 11kV switchgear. Over the next 50 years this will lead to increased charges of \$13 to 19M/yr.

Engineering staff will now proceed to trial new RMUs over the following year which will confirm the cost input for 11 kV switchgear in the model. Analysis can then also be done on the option of using Remote Controlled Circuit Breakers instead of Remote Controlled Switches. All this will enable refinement of the Total cost, which together with a subjective HILP benefit consideration will determine the appropriate 11 kV architecture.

The chart above indicates the preferred option is likely to include one intermediate circuit breaker as this reduces SAIFI. Note this option alone has a small disadvantage for customers past this breaker as the Controller is not aware of any outage until someone calls in (ie no remote indication of an outage). Adding Remote Control and Indication to at least 2 kiosks/feeder removes this disadvantage and reduces SAIDI. Both these gains come for a Total Cost of around \$40k/zone substation/year (<1%).

An intermediate circuit breaker increases resilience by reducing the number of customers affected by some faults. This is particularly valuable as the probability of a damaging Canterbury based fault is now higher than the probability of an Alpine based fault (27% probability of a Canterbury quake over the next 20 years exceeding magnitude 6.5, this is equivalent to the energy release of 1 mega tonne of TNT).⁴

⁴ Supplied by GNS through CERA Utility Transport and Network Providers Forum on 13 February 2012: Probability (Canterbury wide) of 6 – 6.4 quake: 13% (1 year), 34% (5 yr), 64% (20 yr); 6.5 -6.9 quake: 4% (1 yr), 11% (5 yr), 27% (20 yr)

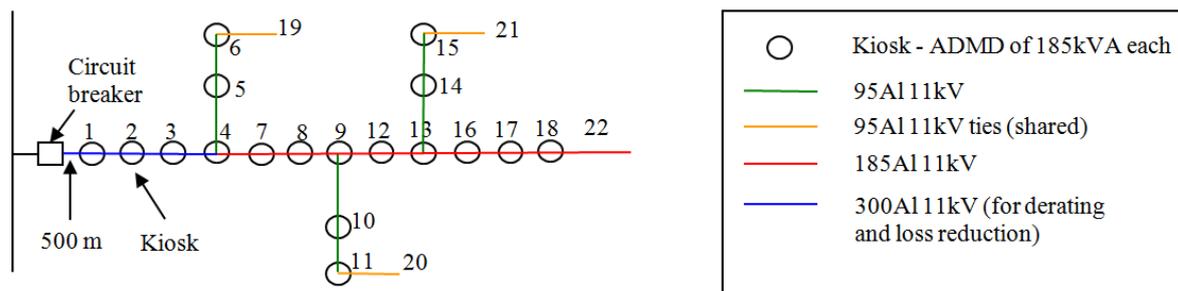
Consideration of having Remote Indication at every 2nd kiosk (or more) is to be revisited when the 400 V review is carried out (currently planned for 2013). Note when it comes to confirming the design for a specific feeder it may be worth slightly refining the placement of remote control depending on the location of major customer load ie remote control is at load centroid rather than kiosk centroid eg if major customer is at kiosk 5 then add remote control at kiosk 4 towards 7 & 6 towards 19 so Controller can isolate cable faults on 7,8,9 and turn 5 (& 6) back on remotely.

The remote indication and control enhancements give flexibility to build on as more product/service options develop in the power supply arena. They give the possibility of interfacing with sophisticated controllers, Home Area Networks or smart phones, which the sectionaliser option does not have.

Full Remote Control and Indication reduces the number of Operators required. If all urban 11kV switchgear was remote switchable (except for site earthing, etc), this could save \$625k/year (based on 5 Operators at \$125k/yr). The ~\$30k/zone substation saving has been taken off the total for the last option shown in the previous chart.

Key Findings for Greenfields

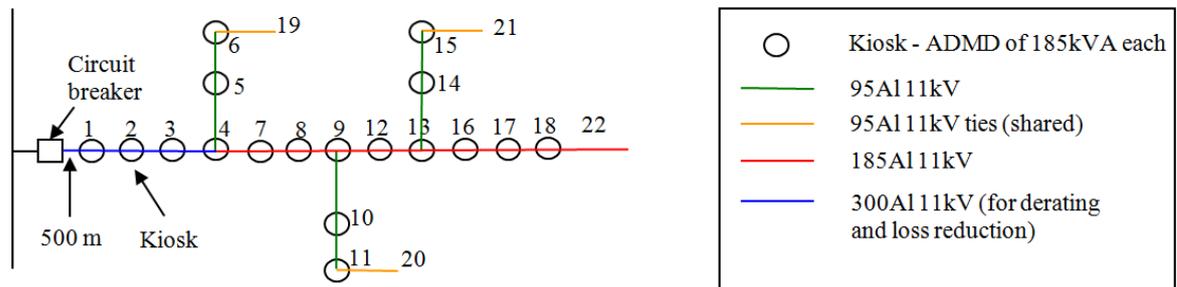
- 1) Optimum feeder layout & cable sizing is the same as current radial practice:



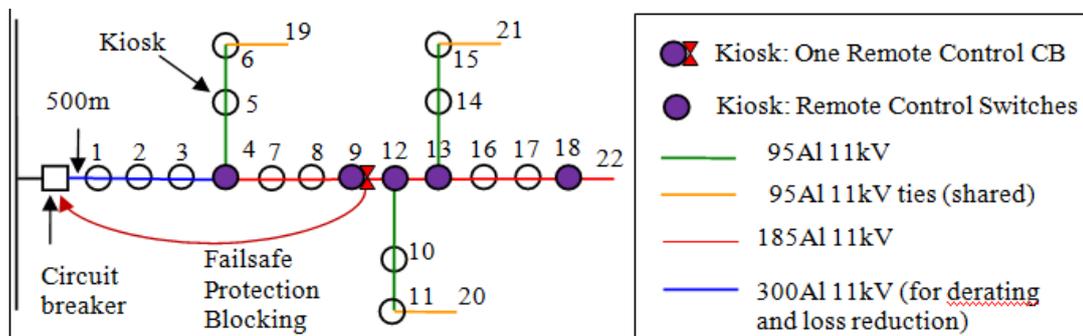
- 2) N-2 subtransmission capacity is appropriate when considering HILP events
- 3) Adding Remote Indication is low cost and significantly reduces the time for the last customer to be restored (from ~100 mins down to ~60 mins)
- 4) Adding Remote Control gives the lowest SAIDI (6.1 mins), and significantly reduces CAIDI (~60 mins to ~30 mins).
- 5) Adding an Intermediate Circuit Breaker is the only way to reduce SAIFI, lowering 0.19 down to 0.14
- 6) Details of best use of partial Remote Control & Indication along feeder to be confirmed once as built costs of new RMU switchgear to replace Magnefix MSU are established (expected in 2013)
- 7) Long term Capital cost increase of ~ 25% due to ceasing use of MSU, with Remote Control & Indication options adding another 2% to 3%
- 8) The four lowest Total cost options are similar (< 2% variance)

Recommendations

- 1) For 40 MW zone substation development, continue using 12 feeder N-2 Inter zone capacity feeder configurations:



- 2) Trial new 11 kV RMU switchgear in 2013 to confirm as built costs
- 3) Use these costs to analyze permutations with an intermediate circuit breaker and Remote Control switches/circuit breakers at some kiosks eg at kiosks 4, 12 and 13:



- 4) Review Remote Indication options as part of LV review
- 5) Let greenfields conclusions guide brownfields approach but assess economics for conversion on an area by area basis.

Appendix A Model & Inputs

Modelling Tool

We have developed a network investment and reliability performance modelling tool which essentially allows a variety of network architectures to be analysed in terms of their construction costs and reliability performance. In this way capital investment and operations **costs** can be compared to the value that customers put on the reliability **benefits**.

The model and the data input assumptions (construction costs, fault rates, value of unserved energy, etc.) have been developed internally and have been subject to an internal review involving network development, asset management, operational and commercial staff members. This process has enabled the quality of input data assumptions and also the output calculation accuracy to be thoroughly challenged and checked.

Participants include GM Development, Strategic Planning Manager, GM Infrastructure, Operations Manager, Engineering Manager, Infrastructure Lifecycle Manager, Engineering Support Manager, Technical Support Manager and the Commercial Analyst.

Inputs

				For sensitivity analysis on Graph tab				
				2006 Review	Factored/Unit \$	Per Unit Cost	Source	
Annual revenue requirement expressed as a % return on capital investment	13.6%			Equipment/Asset Costs				
RMU (no remote) p.a. revenue requirement as % return on capital investment	13.7%			Cable Trench & Reinstale	\$90	\$100	\$100	Pricing DB (63 Rural berm, \$158)
RMU Remote Control p.a. revenue requirement as % return on capital investment	14.0%			11kV 4.4MVA 95AI cable and laying	\$59	\$54	\$54	Connectics + M Miles
15 yr life asset p.a. revenue requirement as % return on capital investment	17.6%			11kV 6.4MVA 185AI cable and laying	\$69	\$65	\$65	Connectics + M Miles
Unplanned Outages VOLL \$kWhr	15.97			11kV 7.2MVA 240AI cable and laying	\$75	\$71	\$71	Estimate + M Miles
Value of Interruption (VOI)	23.18			11kV 8.3MVA 300AI cable and laying	\$81	\$79	\$79	Connectics + M Miles
Load factor for 11kV feeder level sub analysis	0.45			11kV 4.4MVA 95AI cable installed	\$149	\$154		Addition from rows above
				11kV 6.4MVA 185AI cable installed	\$159	\$165		Addition from rows above
				11kV 7.2MVA 240AI cable installed	\$165	\$171		Addition from rows above
				11kV 8.3MVA 300AI cable installed	\$171	\$179		Addition from rows above
				11kV 1250 A CB with remote I & C incl termination		\$85,400	\$61,000	Pricing DB-CB 1200A installed
				11kV 630 A CB with remote I & C incl termination	\$40,000	\$72,800	\$52,000	Pricing DB-CB 630A
				MSU (2K1T)		\$53,340	\$38,100	overcurr + earthfault
				Additional MSU switch and termination	\$4,000	\$5,880	\$4,200	Staff refer Costs July 2012 tab*
				RMU 2 switch, 1 CB (kiosk 1)		\$84,000	\$60,000	Pricing DB
				RMU 2 switch, 2 CB		\$128,800	\$92,000	Staff refer Costs July 2012 tab*
				RMU 1 switch, 3 CB		\$134,400	\$96,000	Staff refer Costs July 2012 tab*
				RMU 3 switch, 1 CB		\$96,600	\$69,000	Staff refer Costs July 2012 tab*
				RMU 2 switch, 1 CB (1 switch remote controlled)		\$93,800	\$67,000	Staff refer Costs July 2012 tab*
				RMU 2 switch (all remote controlled), 1 CB & Indic		\$95,200	\$68,000	Staff refer Costs July 2012 tab*
				RMU 3 switch (all remote controlled), 1 CB & Indic		\$109,200	\$78,000	Staff refer Costs July 2012 tab*
				RMU 2 switch, 1 CB (Remote Retrofit Ready)		\$86,800	\$62,000	Staff refer Costs July 2012 tab*
				RMU 3 switch, 1 CB (Remote Retrofit Ready)		\$100,800	\$72,000	Staff refer Costs July 2012 tab*
				RMU 1 remote ctrl switch, 2CB(1 rmt controlled)		\$124,600	\$89,000	Staff refer Costs July 2012 tab*
				MDI Metering	\$1,290	\$1,547	\$1,547	2006 Review + inflation 20%
				Smart Meter with cell ph comms		\$800	\$1,600	S Milmine
				Network Centre land and Buildings	\$150,000	\$215,600	\$154,000	Staff refer Costs July 2012 tab*
				Operational Costs				
				Operational cost/remote switching		\$4	\$4	Stu Kilduff
				Operation cost/manual onsite switching		\$28	\$28	Stu Kilduff

Ref: [\\Verdi\Groups\\$\Network Development\Network planning\Architecture review 2011\11kV\120926 Economics and Reliability Model.xlsx](\\Verdi\Groups$\Network Development\Network planning\Architecture review 2011\11kV\120926 Economics and Reliability Model.xlsx)

11 kV Inputs including Switchgear WITHOUT Remote Control or Indication

Asset Description	CAPEX	Components	Source
Network Substation land and building	\$154,000	Land \$10,000 Legal/Title \$9,000 Building \$122,400 Design \$13,000	D Wade D Wade R Woods Ref Northwood Boulevard 2005: \$102,000 R Woods
11kV 630A CB with remote indication and control	\$52,000		Pricing DB-CB 630A overcurr + earthfault
11kV 1250A CB with remote indication and control	\$61,000		Pricing DB-CB 1200A installed
11kV 2500A CB with remote indication and control	\$103,500		A Tong
11kV zone protection - solkor	\$3,000		A Parr
MSU (2K1T)	\$38,100	MSU Installation \$9,888 Kiosk - land consideration \$12,200 Kiosk - legal/easement survey \$2,000 Kiosk (full) shell and pad \$4,500	I Wells Pricing DB-2K1T installed D Wade D Wade C Owen
MSU (3K1T)	\$42,300	11kV MSU switch + cable termination - Marginal cost per circuit \$4,200	Pricing DB
RMU 2 switch/1 CB without remote ind and ctrl (with relay on CB)	\$60,000	Entec DC Supply Installation \$24,822 Kiosk - land consideration \$1,000 Kiosk - legal/easement survey \$12,200 New Entec/Transformer kiosk \$4,000	3% Short life (15 yr) portion J Coursey/Steve Mac G Coates J Coursey/I Wells D Wade D Wade C Owen Half Kiosk + Low Kiosk+pads : \$14,000. New Taller Kiosk 2.6m * 2.3m (font & side doors) + 1 easement strip: \$13,000?
RMU 2 switch/2CB without remote ind and ctrl (with relay on CB)	\$92,000	Entec DC Supply Protection Blocking Installed (Fibre link) Installation \$35,324 Kiosk - land consideration \$1,000 Kiosk - legal/easement survey \$20,000 New Entec/Transformer kiosk \$14,800	2% Short life (15 yr) portion J Coursey/Steve Mac G Coates S MacDonald J Coursey/I Wells D Wade D Wade C Owen Half Kiosk + Low Kiosk+pads : \$14,000. New Taller Kiosk 2.6m * 2.3m (font & side doors) + 1 easement strip: \$13,000?
RMU 1 switch/3CB without remote ind and ctrl (with relay on CB)	\$96,000	Entec DC Supply Protection Blocking Installed (Fibre link) Installation \$38,896 Kiosk - land consideration \$1,000 Kiosk - legal/easement survey \$20,000 New Entec/Transformer kiosk \$14,800	4% Short life (15 yr) portion J Coursey/Steve Mac G Coates S MacDonald J Coursey/I Wells D Wade D Wade C Owen Half Kiosk + Low Kiosk+pads : \$14,000. New Taller Kiosk 2.6m * 2.3m (font & side doors) + 1 easement strip: \$13,000?
RMU 3 switch/1 CB 1 without remote ind and ctrl (with relay on CB)	\$69,000	Entec DC Supply Installation \$32,192 Kiosk - land consideration \$1,000 Kiosk - legal/easement survey \$14,800 New Entec/Transformer kiosk \$4,000	3% Short life (15 yr) portion J Coursey/Steve Mac G Coates J Coursey/I Wells D Wade D Wade C Owen Half Kiosk + Low Kiosk+pads : \$14,000. New Taller Kiosk 2.6m * 2.3m (font & side doors) + 1 easement strip: \$13,000?

Without remote indication & control

\$28 for onsite manual switching

11 kV Switchgear WITH Remote Control (\$4/switching Operations cost):

RMU 2 remote controlled switches/1 CB + remote ind (Includes Relay and RTU) Entec Radio DC Supply Installation GE F35 Protection Relay "RTU" + rack Load-Fault Indicator Kiosk - land consideration Kiosk - legal/lease survey New Entec/Transformer kiosk	\$67,000	12% \$30,105 \$1,000 \$1,000 \$13,200 \$0 \$0 \$4,000 \$4,500 \$13,000	Short life (15 yr) portion J Coursey/Steve Mac S MacDonald G Coates J Coursey/I Wells J Coursey S Milmine D Wade D Wade C Owen Half Kiosk +Low Kiosk+pads : \$14,000. New Taller Kiosk 2.6m * 2.3m (front & side doors) + 1 easement strip: \$13,000?
RMU 1 remote control switch/1 remote control CB/1 CB + remote ind (Includes Relay and RTU) Entec Radio DC Supply Installation Protection Blocking Installed (Fibre link) Load-Fault Indicator Kiosk - land consideration Kiosk - legal/lease survey New Entec/Transformer kiosk	\$89,000	31% \$32,630 \$1,000 \$1,000 \$13,200 \$20,000 \$0 \$4,000 \$4,500 \$13,000	Short life (15 yr) portion J Coursey/Steve Mac S MacDonald G Coates J Coursey/I Wells S MacDonald S Milmine D Wade D Wade C Owen Half Kiosk +Low Kiosk+pads : \$14,000. New Taller Kiosk 2.6m * 2.3m (front & side doors) + 1 easement strip: \$13,000?

11 kV Switchgear READY for Remote Control and Indication to be fitted AND Remote Indication OPTION:

RMU 2 switch/1 CB ready for retrofitting remote ind and ctrl (with relay on CB) Entec DC Supply Installation Kiosk - land consideration Kiosk - legal/lease/survey New Entec/Transformer kiosk	\$62,000	3% Short life (15 yr) portion \$26,922 J Coursey/Steve Mac \$1,000 G Coates \$12,200 J Coursey/I Wells \$4,000 D Wade \$4,500 D Wade C Owen Half Kiosk+Low Kiosk+pads: \$14,000. New Taller Kiosk 2.6m * 2.3m (front & side doors) + 1 easement strip: \$13,000?	Ready for Remote Control to be retrofitted Installing remote RTU/radio at a later date would have additional costs of establishing on site, outages, testing and installing the relay & Radio.
RMU 2 switch/2CB ready for retrofitting remote ind and ctrl (with relay on CB) Entec DC Supply GEF25 Protection Relay + rack Installation Kiosk - land consideration Kiosk - legal/lease/survey New Entec/Transformer kiosk	\$75,000	4% Short life (15 yr) portion \$37,424 J Coursey/Steve Mac \$1,000 G Coates \$0 J Coursey \$14,600 J Coursey/I Wells \$4,000 D Wade \$4,500 D Wade C Owen Half Kiosk+Low Kiosk+pads: \$14,000. New Taller Kiosk 2.6m * 2.3m (front & side doors) + 1 easement strip: \$13,000?	
RMU 1 switch/3CB ready for retrofitting remote ind and ctrl (with relay on CB) Entec DC Supply GEF25 Protection Relay + rack Installation Kiosk - land consideration Kiosk - legal/lease/survey New Entec/Transformer kiosk	\$77,000	5% Short life (15 yr) portion \$39,946 J Coursey/Steve Mac \$1,000 G Coates \$0 J Coursey \$14,600 J Coursey/I Wells \$4,000 D Wade \$4,500 D Wade C Owen Half Kiosk+Low Kiosk+pads: \$14,000. New Taller Kiosk 2.6m * 2.3m (front & side doors) + 1 easement strip: \$13,000?	
RMU 3 switch/1 CB 1 ready for retrofitting remote ind and ctrl (with relay on CB) Entec DC Supply Installation Kiosk - land consideration Kiosk - legal/lease/survey New Entec/Transformer kiosk	\$72,000	3% Short life (15 yr) portion \$35,342 J Coursey/Steve Mac \$1,000 G Coates \$14,600 J Coursey/I Wells \$4,000 D Wade \$4,500 D Wade C Owen Half Kiosk+Low Kiosk+pads: \$14,000. New Taller Kiosk 2.6m * 2.3m (front & side doors) + 1 easement strip: \$13,000?	
Remote Indication Smart Meter Load-Fault Indicator Installation	\$1,600	\$900 S Milmine \$0 S Milmine (not needed as incl in Entec RMU) \$700 S Milmine	

NB All 11kV installed & terminated

Note that the Entec is still in development stage and a comparable 25W/1CB product that is available on the market now is about \$ 34,300 but would still need RTU

Reference: [\\Verdi\Groups\\$\Network_Development\Network_planning\Architecture review 2011\11kV\120926 Economics and Reliability Model.xlsx](#), Sheet:11 kV Costs July 2012”

Appendix B Ring Main Unit Paper for 11kV Architecture review

Author: Steve Macdonald

Date: 18 July 2012

Version: Draft

Approved: _____

Date: _____

Table of Contents

8.1 Background	18
8.2 Arc Flash	18
8.3 Use of the Magnefix Switching Units in our 11kV architecture.....	19
8.4 Conclusion.....	20

1.1 Background

Within the Orion network and other networks throughout New Zealand, distribution companies use a ring main unit (RMU) to distribute the HV network around the area. The supplier and types of these vary greatly between companies.

Our current ring main unit, the Magnefix Switching Unit (MSU) has been in manufacture for over 40 years. There has been no significant development of the product recently that would align to safety requirements (arc containment) of IEC standard 62271 Part 200. We consider the product to be a “twilight” product in that while its performance does not warrant removal from our network; it is not suitable for new installations to be introduced into the network. New products are now becoming available to the market that deliver a much improved safety and operational outcome. We are actively looking for suitable switchgear that will meet our safety, environment, technical and network operational requirements.

1.2 Arc Flash

The EEA Guide for Arc Flash Hazards says that “If the potential employee exposure to an incident energy of greater than 1.2 cal/cm² exists the asset owner shall take all practicable steps to

- Eliminate the exposure, i.e. reduce it to no more than 1.2cal/cm², or
- If elimination is not practicable, isolate the exposure from employees, or

If elimination or isolation is not practicable, minimise the exposure and provide protective equipment to employees

The Electricity Safety Regulations require “... the effect of the safety management system is that all practicable steps are taken to prevent the works from presenting a significant risk of—

- (i) serious harm to any member of the public; or
- (ii) significant damage to property owned by a person other than the safety management system operator

The EEA “Guide for the Management of Arc Flash Hazards (Oct 11)” states that:

“An arc flash protection boundary shall also be established for work in public areas, and all persons not wearing appropriate PPE shall remain beyond the boundary. Note: Arc flash protection boundaries cannot be used where the public has uncontrolled access to the vicinity of the equipment, e.g. on roadsides and other public areas, except when a workparty is at the site. For protection of the public when work is not taking place, controls need to be inherently safe, e.g. barriers, safety by design etc.”

The IEEE standard 1584 has rapidly become the definitive authority for the analysing of arc flash and it is now widely adopted.

This standard has been used to develop strategies that have the goal of minimising burn injuries.

The Orion PPE standard NW21.07.03 was developed using the calculation method of the model formed from IEEE 1584.

The model not only determines the required level of PPE gear to sustain a flash without suffering burns, but also determines the Arc Flash Boundary where everyone inside that boundary must be dressed in the specified protective equipment or specifically excluded from the area.

If we use the IEEE 1584 model with a 14 Ka fault level, then a clearance delay of 100 milliseconds results in requiring PPE equipment that can withstand 2.69 cal/cm². Our PPE standard is set to 16.0 cal/cm² and the Arc Flash boundary required is 1.32 metres. An operator should be able to ensure no one else is inside this boundary, particularly members of the public.

If we model the slower clearance time of 510 milliseconds, as is required with one of the network architecture options involving intermediate switchgear, the PPE gear must withstand 13.7 cal/cm². This is close to the maximum rating of NW21.07.03 and the ARC Flash boundary has increased to 7.13 metres, meaning we would need to close the footpath and or road?

The requirement to prevent access to the public inside the Arc Flash area is present even when workers are not on site so barriers are required to exclude access.

Orion's ongoing strategy around managing arc flash is:

- By using the safety by design criteria, ensure new switchgear installations being installed contain arc containment appropriate for the environment, i.e. IEC standard 62271 Part 200. We are currently investigating suitable equipment for installation in the network.
- Ensure existing installations with arc flash risk are appropriately risk managed by minimising exposure levels, use of procedures and PPE

1.3 Use of the Magnefix Switching Units in our 11kV architecture

The greatest risk for Orion around the continuation of the installation of MSUs in both new and existing substations is the level of safety from Arc Flash Prevention that it affords.

As the MSU switchgear is a cast resin switching unit, it does not provide for Arc Flash protection to either the worker, adjacent property or the public.

Although it has proven to be a reliable product in the past, the changing nature of the network means the Magnefix is being subjected to different operating criteria, including switching of higher currents than in the past. So is it a operator safety switching issue - not a public issue.

Discussions with two other NZ companies who had a large number of MSU's has shown that due to safety concerns, they are no longer installing MSUs into their network. There are no proposals from the manufacturer to install Magnefix in an arc contained environment. Therefore to remove or limit future exposure we must look to install new switchgear to standard 62271 Part 200. This is in line with current international practise.

The move from our traditional primary based 11kV network to some of the radial network options being considered has brought a concern that protection clearance times are becoming longer and poses a greater safety risk to the public and workers. However, these radial network options are not proposed feasible/acceptable without additional communication signalling to achieve fast clearance times and therefore this is not a justified concern.

When switching at kiosks that have MSU's fitted protective clothing conforming to NW21.07.03 is required to be worn which only addresses the risk to the worker and not the public.

Management of risk associated with existing installations will need to be addressed. This will include, monitoring of incidents, reviews of levels of site risk exposure levels, possible targeted risk mitigation procedures, and ensuring appropriate maintenance and operating programmes and procedures are in place

1.4 Conclusion

Orion's network requirements in the future will require new purchases of ring main units that meet IEC 62271 Part 200. This will mean that new Magnefix switchgear will not be purchased when a suitable alternative that meets the safety, quality and operational objectives of the business is available.

We propose to risk manage existing live front MSU's to ensure safety to workers and public safety.

Any future planning and budget modelling should allow for a change in switchgear type and costings. Our review of the current suitable switchgear available on the market means that we will change our RMU purchasing during 2013.

Appendix 8

Wire Scan's Cable Testing Report



Orion
Christchurch

Via Siemens New Zealand

Att: Darran Mumford

Your reference:

Our reference: rev1

Sarpsborg 06.04.2011

Wirescan AS

Sundløkkaveien 75
1659 Torp

Norway

E-mail: info@wirescan.no

Web: www.wirescan.no

Org No · 988777107 MVA

Summary measurements in Christchurch March 2011

Measurements performed 24 and 25 March 2011. The uncertainty in the measurements is ± 20 meter from the given length unless otherwise stated.

Armagh – Lancaster 2363m XLPE (186-146), measured from Armagh

Very strong indications of impedance changes at 4 locations that were not in area of joints:
568 (± 3 m), 1150 (± 3 m), 1750 (± 15 m) and 2060 meter

Armagh – Addington no 2 4416 m oil (ADD126-ARM136), measured from Armagh

Strong indications of impedance changes at 5 locations not in area of joints:
350, 1355, 2085, 2764 and 3460 meter.

Armagh – Addington no 1 4282 m oil (ADD66B-ARM116), measured from Armagh to joint at 1461

Indications of impedance changes at 1 locations: 350 meter

Knox – Addington (Addington unit 11 – Knox unit 17) 3177 m oil measured from Knox

Only indications of impedance changes in the regions of known joints.

Addington – Milton 66 kV 3990 m oil measured from Addington

Only indications of impedance changes in the regions of known joints.
In area around 3100 meter there is indications in one of the phases (blue).

Addington - Oxford Tuam No 2 measured from Addington

Only indications of impedance changes in the regions of known joints.

Papanui – McFadden 66kV Oil measured from Papanui

Only indications of impedance changes in the regions of known joints.
The impedance change in the joint at 2651 meter is however significant larger than in the other observed joints.

Papanui – McFadden 66kV Oil measured from Papanui

Only indications of impedance changes in the regions of known joints.
There is however a significant impedance change in the area of 250 meter. This is probably caused by several joints close together in this area.

Sincerely yours / Best regards

Jon Ivar Juvik
Senior Engineer
Wirescan AS

Mobile: +47 48 13 86 01
E-mail: jjj@wirescan.no

Appendix 9

Detailed data tables for proposed quality standards

Appendix 9 Supporting SAIDI and SAIFI Data

SAIDI	Reference Dataset 1					Reference Dataset 2					YTD	Post EQ Part Year 2011	2012 Calendar YTD Jan-12	05 - 09 Average	08 - 12 Average	Post Quake Average	µSAIDI					
	2005	2006	2007	2008	2009	2008	2009	2010	2011	2012							2013	2014	2015	2016	2017	2018
Rural																						
11kV											Aug-12											
3rd Party Damage	1.130	2.277	2.044	1.125	0.857	1.125	0.857	1.855	1.770	1.477	1.345	1.238	2.247	1.487	1.417	2.030	1.417	1.417	1.417	1.417	1.417	1.417
External Factors	12.051	14.726	21.997	10.863	13.012	10.863	13.012	8.822	15.987	22.898	16.096	12.980	24.087	14.530	14.316	25.987	14.316	14.316	14.316	14.316	14.316	14.316
System Failure	6.133	9.570	6.893	5.811	9.596	5.827	9.596	9.062	10.947	11.624	5.704	7.406	10.084	7.601	9.411	12.367	12.367	11.414	10.461	9.507	8.554	7.601
Planned Outage	6.691	4.669	6.025	8.719	17.916	8.728	17.916	19.464	4.974	7.772	2.020	2.609	6.660	8.804	11.771	6.201	11.771	11.771	11.771	11.771	11.771	11.771
Sub Total	26.006	31.242	36.959	26.518	41.381	26.543	41.381	39.202	33.678	43.772	25.165	24.233	43.078	32.421	36.915	46.585	39.871	38.918	37.965	37.011	36.058	35.105
33kV																						
3rd Party Damage	0.000	0.000	0.111	0.000	0.167	0.000	0.167	0.000	0.000	0.000	0.000	0.000	0.000	0.056	0.033	0.000	0.033	0.033	0.033	0.033	0.033	0.033
External Factors	3.839	2.737	1.105	3.007	1.851	3.007	1.851	1.453	8.043	1.540	0.120	5.524	1.264	2.508	3.179	3.592	3.179	3.179	3.179	3.179	3.179	3.179
System Failure	0.237	1.611	0.888	3.684	3.342	3.684	3.342	2.205	1.155	0.250	0.739	1.155	1.005	1.953	2.127	1.072	2.127	2.127	2.127	2.127	2.127	2.127
Planned Outage	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Sub Total	4.076	4.348	2.105	6.691	5.361	6.691	5.361	3.657	9.198	1.790	0.859	6.679	2.270	4.516	5.340	4.664	5.340	5.340	5.340	5.340	5.340	5.340
66kV																						
3rd Party Damage	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.430	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
External Factors	0.000	0.766	0.054	0.000	0.106	0.000	0.106	0.000	0.243	0.067	0.000	0.243	0.000	0.185	0.083	0.155	0.083	0.083	0.083	0.083	0.083	0.083
System Failure	0.108	0.000	0.000	0.000	0.021	0.000	0.021	0.000	0.086	0.000	0.041	0.000	0.041	0.026	0.021	0.020	0.021	0.021	0.021	0.021	0.021	0.021
Planned Outage	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Sub Total	0.108	0.766	0.054	0.000	0.127	0.000	0.127	0.000	0.329	0.067	0.041	0.243	1.471	0.211	0.105	0.175	0.105	0.105	0.105	0.105	0.105	0.105
Rural Total	30.190	36.357	39.118	33.210	46.869	33.235	46.869	42.860	43.205	45.629	26.065	31.155	46.819	37.149	42.359	51.425	45.316	44.362	43.409	42.456	41.502	40.549
Urban																						
11kV																						
3rd Party Damage	1.047	0.895	2.251	0.930	2.003	0.930	2.003	1.274	0.747	1.602	1.081	0.147	1.729	1.425	1.311	1.415	1.889	1.889	1.889	1.889	1.889	1.889
External Factors	5.941	4.706	4.672	3.857	4.171	3.857	4.171	5.292	7.056	13.105	4.669	5.536	10.315	4.670	6.696	11.655	6.696	6.696	6.696	6.696	6.696	6.696
System Failure	12.806	7.792	4.542	5.057	5.398	5.057	5.398	6.241	12.324	26.468	4.770	8.494	12.860	7.119	11.097	19.866	19.866	17.316	14.767	12.218	9.668	7.119
Planned Outage	0.989	1.312	2.755	1.459	3.271	1.459	3.271	1.253	1.170	2.154	0.221	0.840	1.247	1.957	1.861	1.607	3.723	3.723	3.723	3.723	3.723	3.723
Sub Total	20.783	14.706	14.220	11.303	14.843	11.303	14.843	14.059	21.298	43.328	10.740	15.017	26.151	15.171	20.966	34.543	32.173	29.624	27.075	24.525	21.976	19.427
33kV																						
3rd Party Damage	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
External Factors	0.000	0.000	0.008	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.135	0.000	0.135	0.002	0.000	0.067	0.000	0.000	0.000	0.000	0.000	0.000
System Failure	0.109	0.577	1.430	0.005	0.016	0.005	0.016	0.000	0.001	0.000	0.000	0.001	0.000	0.428	0.004	0.000	0.004	0.004	0.004	0.004	0.004	0.004
Planned Outage	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Sub Total	0.109	0.577	1.438	0.005	0.016	0.005	0.016	0.000	0.001	0.000	0.135	0.001	0.135	0.429	0.004	0.068	0.004	0.004	0.004	0.004	0.004	0.004
66kV																						
Baseline 66kV Urban	0.569	0.451	0.000	0.303	0.000	0.303	0.000	4.225	0.000	7.070	0.000	0.000	6.794	0.265	2.320	3.535	0.265	0.265	0.265	0.265	0.265	0.265
Not Subject to 66kV Urban Upgrades																						
Subject to 66kV Urban Upgrades																						
Sub Total	0.569	0.451	0.000	0.303	0.000	0.303	0.000	4.225	0.000	7.070	0.000	0.000	6.794	0.265	2.320	3.535	18.032	18.249	13.413	13.376	9.002	4.349
Urban Total	21.461	15.735	15.657	11.612	14.859	11.612	14.859	18.283	21.299	50.398	10.874	15.018	33.080	15.865	23.290	38.145	50.210	47.877	40.492	37.905	30.983	23.780

SAIFI	Reference Dataset 1				
Rural	2005	2006	2007	2008	2009
11kV					
3rd Party Damage	0.008	0.029	0.029	0.019	0.015
External Factors	0.153	0.165	0.237	0.110	0.119
System Failure	0.078	0.098	0.089	0.077	0.133
Planned Outage	0.022	0.018	0.022	0.033	0.061
Sub Total	0.260	0.310	0.378	0.239	0.328
33kV					
3rd Party Damage	0.000	0.000	0.002	0.000	0.002
External Factors	0.055	0.050	0.044	0.063	0.028
System Failure	0.031	0.038	0.018	0.100	0.058
Planned Outage	0.000	0.000	0.000	0.000	0.000
Sub Total	0.085	0.088	0.063	0.163	0.088
66kV					
3rd Party Damage	0.000	0.000	0.000	0.000	0.000
External Factors	0.000	0.011	0.001	0.000	0.001
System Failure	0.002	0.000	0.000	0.000	0.004
Planned Outage	0.000	0.000	0.000	0.000	0.000
Sub Total	0.002	0.011	0.001	0.000	0.006
Rural Total	0.348	0.409	0.442	0.403	0.422

Reference Dataset 2					YTD	Post EQ Part Year	2012 Calendar YTD
2008	2009	2010	2011	2012	2013	2011	
					Aug-12		
0.019	0.015	0.022	0.033	0.009	0.011	0.024	0.020
0.110	0.119	0.113	0.145	0.204	0.118	0.110	0.202
0.078	0.133	0.098	0.091	0.157	0.059	0.060	0.116
0.033	0.061	0.077	0.028	0.028	0.011	0.009	0.025
0.240	0.328	0.310	0.297	0.398	0.198	0.202	0.364
0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
0.063	0.028	0.019	0.061	0.015	0.004	0.026	0.023
0.100	0.058	0.038	0.033	0.002	0.015	0.033	0.019
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
0.163	0.088	0.057	0.094	0.017	0.019	0.060	0.042
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.074
0.000	0.001	0.000	0.002	0.005	0.000	0.002	0.000
0.000	0.004	0.000	0.001	0.000	0.001	0.000	0.001
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
0.000	0.006	0.000	0.003	0.005	0.001	0.002	0.075
0.403	0.422	0.366	0.394	0.419	0.219	0.264	0.481

05 - 09 Average	08 - 12 Average	Post Quake Average
0.020	0.019	0.022
0.157	0.138	0.216
0.095	0.111	0.137
0.031	0.046	0.024
0.303	0.315	0.399
0.001	0.000	0.000
0.048	0.037	0.023
0.049	0.046	0.025
0.000	0.000	0.000
0.098	0.084	0.048
0.000	0.000	0.000
0.003	0.002	0.003
0.001	0.001	0.001
0.000	0.000	0.000
0.004	0.003	0.004
0.405	0.401	0.451

µSAIFI					
2014	2015	2016	2017	2018	2019
0.019	0.019	0.019	0.019	0.019	0.019
0.138	0.138	0.138	0.138	0.138	0.138
0.137	0.129	0.121	0.112	0.104	0.095
0.046	0.046	0.046	0.046	0.046	0.046
0.341	0.332	0.324	0.315	0.307	0.298
0.000	0.000	0.000	0.000	0.000	0.000
0.037	0.037	0.037	0.037	0.037	0.037
0.046	0.046	0.046	0.046	0.046	0.046
0.000	0.000	0.000	0.000	0.000	0.000
0.084	0.084	0.084	0.084	0.084	0.084
0.000	0.000	0.000	0.000	0.000	0.000
0.002	0.002	0.002	0.002	0.002	0.002
0.001	0.001	0.001	0.001	0.001	0.001
0.000	0.000	0.000	0.000	0.000	0.000
0.003	0.003	0.003	0.003	0.003	0.003
0.427	0.419	0.410	0.402	0.393	0.385

SAIFI	Reference Dataset 1				
Urban	2005	2006	2007	2008	2009
11kV					
3rd Party Damage	0.024	0.020	0.043	0.016	0.032
External Factors	0.101	0.063	0.065	0.057	0.054
System Failure	0.225	0.162	0.070	0.098	0.077
Planned Outage	0.005	0.008	0.010	0.007	0.016
Sub Total	0.356	0.253	0.188	0.177	0.179
33kV					
3rd Party Damage	0.000	0.000	0.000	0.000	0.000
External Factors	0.000	0.000	0.000	0.000	0.000
System Failure	0.002	0.011	0.046	0.005	0.000
Planned Outage	0.000	0.000	0.000	0.000	0.000
Sub Total	0.002	0.011	0.047	0.005	0.000
66kV					
Baseline 66kV Urban	0.032	0.068	0.000	0.040	0.000
Not Subject to 66kV Urban Upgrades					
Subject to 66kV Urban Upgrades					
Sub Total	0.032	0.068	0.000	0.040	0.000
Urban Total	0.390	0.332	0.235	0.223	0.179

Reference Dataset 2					YTD	Post EQ Part Year	2012 Calendar YTD
2008	2009	2010	2011	2012	2013	2011	Jan-12
							Nov-12
0.016	0.032	0.024	0.019	0.034	0.024	0.003	0.038
0.057	0.054	0.060	0.084	0.097	0.048	0.067	0.090
0.098	0.077	0.087	0.155	0.544	0.115	0.104	0.278
0.007	0.016	0.007	0.005	0.015	0.001	0.004	0.003
0.177	0.179	0.178	0.263	0.690	0.188	0.178	0.409
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.002
0.005	0.000	0.000	0.000	0.000	0.000	0.000	0.000
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
0.005	0.000	0.000	0.000	0.000	0.002	0.000	0.002
0.040	0.000	0.032	0.000	0.167	0.000	0.000	0.121
0.040	0.000	0.032	0.000	0.167	0.000	0.000	0.121
0.223	0.179	0.210	0.263	0.858	0.190	0.178	0.533

05 - 09 Average	08 - 12 Average	Post Quake Average
0.027	0.025	0.030
0.068	0.070	0.106
0.126	0.192	0.382
0.009	0.010	0.010
0.231	0.298	0.528
0.000	0.000	0.000
0.000	0.000	0.001
0.013	0.001	0.000
0.000	0.000	0.000
0.013	0.001	0.001
0.028	0.048	0.084
0.028	0.048	0.084
0.272	0.347	0.613

µSAIFI					
2014	2015	2016	2017	2018	2019
0.042	0.042	0.042	0.042	0.042	0.042
0.070	0.070	0.070	0.070	0.070	0.070
0.382	0.331	0.280	0.229	0.177	0.126
0.020	0.020	0.020	0.020	0.020	0.020
0.514	0.463	0.412	0.361	0.310	0.259
0.000	0.000	0.000	0.000	0.000	0.000
0.000	0.000	0.000	0.000	0.000	0.000
0.001	0.001	0.001	0.001	0.001	0.001
0.000	0.000	0.000	0.000	0.000	0.000
0.001	0.001	0.001	0.001	0.001	0.001
0.028	0.028	0.028	0.028	0.028	0.028
0.148	0.150	0.073	0.073	0.000	0.000
0.148	0.150	0.146	0.146	0.146	0.068
0.324	0.328	0.247	0.246	0.173	0.096
0.839	0.792	0.660	0.608	0.484	0.356

Appendix 10

Regulatory decisions regarding catastrophic events

Regulatory decisions regarding catastrophic events

This appendix details how selected international regulators respond to catastrophic events.

For each jurisdiction, we detail the regulatory mechanism for responding to the event, the speed at which any price changes occur, whether 'claw-back' is allowed to be recovered, and whether suppliers are compensated for revenue reductions in addition to cost increases.

Essential Services Commission – regulation of Victorian (Australia) water and wastewater suppliers

Mechanism for adjusting regulatory settings in response to a natural disaster

The current price determinations for each supplier (they each have a separate one) include a mechanism where suppliers can apply for an adjustment to price in response to events which were unforeseen or uncertain at the time of the decision (including catastrophic events).¹

Timing of adjustment to prices

Prices can be adjusted within the regulatory period, from the year after the event.

Recovery of claw-back

Suppliers can be compensated for all financial effects of the event in NPV terms. This is equivalent to the application of claw-back.

Compensation for revenue reductions

Prices can be adjusted in response to higher than expected costs or lower than expected demand.

In 2010, Coliban Water applied for a price adjustment on the basis of lower than expected demand (and revenue). Its prices were adjusted.²

Ofgem – regulation of UK electricity distributors

Mechanism for adjusting regulatory settings in response to a natural disaster

Distributors have a clause in their licences which allow them to apply to re-open a price control for any reason ('disapplication').³ The licence conditions are non-specific, and Ofgem has substantial discretion to decide whether price adjustments are appropriate.

Timing of adjustment to prices

Revised prices are typically applied around 2 years after an application.

Recovery of claw-back

This is at Ofgem's discretion.

¹ See for example: Essential Services Commission (June 2008), *2008 Water price review: Coliban Water determination 1 July 2008 – 30 June 2013*, Section 4.

² Essential Services Commission (June 2010), *Coliban Water application for tariff adjustment: Determination under clause 4 of the 2008 water price review final decision; Coliban Water determination*.

³ See for example: Ofgem, issued by the Secretary of State (2001), *SP Distribution Limited – Electricity Distribution Licence*, Special Conditions E4 and F2.

Compensation for revenue reductions

Distributors can apply for a price control disapplication on the grounds of both higher costs and lower demand. However the final determination is at Ofgem's discretion.

Ofwat – regulation of UK water and wastewater suppliers

Mechanism for adjusting regulatory settings in response to a natural disaster

Each supplier has a clause in its licence which allows it to apply for an interim determination of prices in response to a 'substantial effect'.⁴ A supplier can apply for an interim determination in response to any event which has a financial impact on the supplier above a specified threshold.

Timing of adjustment to prices

Revised prices are applied from the year after application. This may be the year after the event, but possibly later (since the application must be made by a certain date each year, and it may take a period of time after the event to gather sufficient evidence of the effects).

Recovery of claw-back

The financial impact on the supplier is calculated from the date of the event. The revised prices are set so that the supplier is fully compensated for the financial effects in NPV terms. This is equivalent to the application of claw-back.

Compensation for revenue reductions

The substantial effect can relate to higher costs, lower demand, or both.

⁴ See for example: Department of the Environment (August 1989), *Instrument of Appointment by the Secretary of State for the Environment of Thames Water Utilities Limited as a water and sewerage undertaker under the Water Act 1989*, Part IV, clauses 13.1 and 13.2.

Appendix 11

Marsh's Report on Orion's Network Catastrophe Insurance

ORION'S NETWORK CATASTROPHE INSURANCE

- **Material Damage Insurance**
- **Business Interruption Insurance**

AN EXPERT REPORT FOR ORION AND THE COMMERCE COMMISSION

Paul Casey – Executive Director – Marsh Limited
8 October 2012

CONTENTS

1	Introduction	1
2	The insurance market	2
3	The availability of MD and BI insurance	4
4	The relationship between MD and BI insurance cover.....	7
5	The evolution of insurance markets.....	8
6	The forecast evolution of relevant insurance markets.....	10
7	Strategies to manage risk transfer.....	11
8	Captive insurance and mutual group funding	12
9	Orion’s approach to MD and BI insurance.....	14
10	Network owners’ future approach.....	16
11	Catastrophe insurance claims can be complex	17
12	Marsh credentials.....	18

1 Introduction

The purpose of this report is to respond to Orion's request for an expert report on material damage (MD) and business interruption (BI) insurance matters – especially as they relate to Orion.

Orion's request was dated 20 August 2012 and specifically asked as follows:

“We seek an expert report which addresses the prudence of Orion's past and projected approach to insurance.

In particular we require a report which:

- describes the characteristics of the insurance market (in New Zealand and globally) for long life infrastructure, with particular emphasis on electricity distribution networks*
- describes the historical and forecast insurance availability and terms (including premium rates) of the major categories of assets within electricity distribution networks – for example substations, underground cables and overhead lines – and whether these are considered economic*
- describes the relationship between material damage cover and business interruption cover*
- explains how these markets have evolved to date, particularly in the last decade*
- considers how insurance markets are likely to evolve over the next decade, with particular emphasis on potential changes to the management of catastrophic damage, and the associated costs of insurance*
- sets out the strategies currently employed by network owners in Australasia and globally to manage the risks of damage to their networks, with examples, including consideration of the costs and terms of insurance and the levels of real risk transfer that have been or can be achieved (transfer to a 100% owned captive alone is not considered to be real risk transfer) – where practicable this should be categorised by major asset category (substations, line, cables)*
- considers whether network owners are changing, or are expected to change, their approach to insurance over the next decade, in response to changing market conditions*
- assesses the prudence of Orion's past and planned insurance approach, with particular emphasis on the policies in place at the time of the Christchurch earthquakes, and the reasonableness or otherwise of continuing with that approach to 2019 (the end of the CPP period).*

The report should also include a summary of your credentials relevant to the scope of work set out above.

We require a draft report by 27 September and a final report by 15 October. The report will be included in Orion's CPP proposal, and will become publicly available before or during the Commerce Commission's assessment of the proposal.”

2 The insurance market

The major areas Marsh Ltd has been asked to address are insurance for long life infrastructure for electricity distribution businesses (EDBs):

- substations
- underground cables and overhead lines.

EDBs' key substations are normally insured under an MD insurance policy.

Underground cables and overhead lines, are referred to as transmission and distribution (T&D) risks and are normally uninsured.

Marsh does not act for all EDBs and transmission companies in Australasia, however to the best of my knowledge and belief no EDBs or transmission companies in Australasia, with the exception of those noted below, insure their T&D (overhead lines and underground cables) risks.

The one exception that I can confirm is Powerlink in Queensland, a transmission company that purchases T&D Insurance. Premiums are lower for Transmission companies because the plant is more robust than for EDB's and the risk is spread over wider geographical areas.

Insurance companies are not typically able to provide MD and BI insurance cover for T&D because T&D is specifically excluded from their reinsurance treaty arrangements. This is a global position due to the major T&D risks posed by natural disasters and catastrophes, which insurers and reinsurers globally require to be addressed on a case-by-case basis.

The major risks to T&D for transmission companies and EDBs depend on their location but they normally include:

- fire
- lightning
- explosion
- windstorm
- flood
- hail
- snow
- ice
- frost
- typhoon
- hurricane
- tornado
- tsunami
- cyclone
- aircraft and other aerial devices
- other impacts
- volcanic eruption
- subterranean fire
- thermal activity
- terrorism/vandalism
- earthquake
- negligence/incorrect operation.

Currently all of these risks for Orion are uninsurable as T&D insurance is not available for risks in Christchurch. If insurance was available it would at a minimum exclude cover for terrorism, damage from wilful neglect and failure from internal causes.

Insurers believe that insurable risks can be aggregated in limited geographic areas. They believe that this can concentrate the risks from a single natural disaster, which adds to the aggregate exposures that insurers face in that region, from all the other risks they insure. If a catastrophic event occurs, it has potential to cause a significant single event exposure for insurers, which adversely affects their reinsurance and their retained aggregate exposure to natural disasters. All insurers carry retentions to their own account, whether by virtue of a reinsurance deductible or because their exposures aren't fully reinsured.

3 The availability of MD and BI insurance

MD and BI insurance has been difficult to purchase for EDBs globally.

From circa 1980 until 2001, New Zealand EDBs purchased T&D insurance cover through a scheme called “TRIP” (transmission reticulation insurance programme). TRIP was MD cover only. It did not cover BI risks.

TRIP provided New Zealand EDBs with adequate amounts of MD catastrophe cover for their respective electricity distribution networks, with relatively low deductibles.

TRIP covered all EDB distribution network assets – this included overhead lines and underground cables.

Up until 1998 TRIP was arranged through the Electricity Networks Association. From 1999 to 2001 the scheme was managed directly by Marsh.

The lead insurer for TRIP was HIH Australia and when HIH Australia failed in March 2001 it triggered the reason the TRIP cover ceased to operate.

HIH was reinsured by Swiss Reinsurance, headquartered in Zurich. The balance of the insurance capacity was made up with support from a number of Lloyd’s syndicates from London (each Lloyd’s syndicate participated in small percentages).

TRIP cover was in two layers. The first \$15m layer was enough to cover the majority of the (smaller) EDBs. A few (larger) EDBs purchased higher limits and it made sense economically to purchase this in the form of additional separate layers. Only three EDBs purchased cover above the \$15m primary layer in the year 2000. They were Hawkes Bay Networks, United Networks and Orion.

The primary \$15m layer cost Orion approximately \$0.14m - a rate of 0.9%. Orion’s second layer of \$29m cost approximately \$0.05m at a rate of 0.19%. The average combined rate on Orion’s \$44m of MD cover was approximately 0.45%.

Orion made a number of claims under TRIP:

- 1968 windstorm \$1.30m
- 1973 snow damage \$1.25m
- 1974 windstorm \$3.75m
- 1975 windstorm \$0.10m
- 1993 snow damage \$1.20m
- 1995 snow damage \$0.10m.

The TRIP underwriters significantly increased Orion's deductible to \$1.25m in the year 2000. This increased deductible was the second highest deductible for participating EDBs. This increase was a reflection of Orion's past claims record.

TRIP ceased in April 2001 from a combination of factors. In 1999 the fire and general insurance industry experienced deteriorating profitability and there were a number of significant (at that time) natural disasters. 1999 was a bad year for insured natural disasters – this included significant insurance losses from major storms in Europe in December 1999.

These factors all resulted in:

- substantial increases in TRIP's reinsurance rates and
- less capacity for "*difficult to place*" risks – risks such as T&D.

TRIP had different renewal dates for different EDBs. EDBs that renewed at the end of 1999 saw reduced participation from London based insurers (such as Lloyd's), which resulted in only 70% coverage for loss above the primary \$15m layer.

This triggered the move to a common renewal date of 1 April. All underwriters other than HIH reduced their capacity from 1 April 2000 and premiums increased by more than 10%. Then TRIP experienced a large loss/claim – approximately \$5m.

Amalgamation of a number of EDBs with ability to retain risk (which reduced the premium pool for insurers) contributed to the difficulties for insurers. HIH Australia itself faced major legal and financial pressures and reinsurers became less willing to continue to support HIH.

So TRIP collapsed in 2001.

TRIP had been attractive for New Zealand EDBs – it had relatively low deductibles, it covered most of the network assets of EDBs to specified limits and the premiums were affordable.

There have been a couple of attempts since TRIP's collapse to launch a replacement scheme for EDBs. However these attempts have not been successful (even before the Canterbury earthquakes) because:

- the minimum deductibles offered have been in the region of \$5m and
- the (even before the Canterbury earthquakes) premiums required by insurers have been in the region of 7.5% to 10% of the policy limit. This level of premium rate is considerably greater than the TRIP scheme – around 20 times more expensive.

For example, a premium cost of 10% would mean that an EDB would have to have a **total loss of its electricity network at least every ten years** in order to be "*in the money*" on its T&D insurance cover. On this basis, EDBs (including Orion), have reasonably concluded that this cover for overhead lines and underground cables is not economic, even if it is available.

Insurers are clearly reluctant to offer cover to EDBs for T&D risks in earthquake zones.

Insurers believe that:

- EDBs have the majority of their assets in relatively concentrated geographic locations. The potential for large “*single event*” losses for lines, cables and substations is significant
- transmission companies (for example Transpower) have wide geographic spreads and depending on the natural disaster risk in their geography are generally less exposed to large “*single event*” losses
- transmission companies have more robust transmission and distribution plant, generally designed to withstand specific types and levels of natural disaster with proportionally lower values below ground
- the T&D “*single event*” risk profile for EDBs is therefore higher than for transmission companies.

4 The relationship between MD and BI insurance cover

BI insurance covers specified loss of revenues and specified increased costs of working.

BI is only very rarely offered by insurers on a stand-alone basis. The insured must first purchase MD insurance.

With limited exceptions, BI claims are only triggered by BI losses caused by damage to physical assets which are specifically insured under an associated MD policy.

In our opinion, EDBs have no MD insurance cover for T&D because EDBs have reasonably concluded that this cover is not economically available.

So there is no BI (loss of profits or revenue, or increased costs of working) insurance available for T&D. Despite the fact that the large majority of EDBs' assets are T&D, and despite the catastrophe risk they face to those T&D assets, EDBs such as Orion therefore have no T&D insurance cover for:

- MD or
- BI.

EDBs are therefore not covered (that is, they are uninsured) for BI type losses (increased costs of working and lower revenues) caused by:

- physical damage to T&D (for example Orion had over ten kilometres of 11kV underground cable faults following the 22 February 2011 quake)
- general depopulation, reduced consumption, reduced customer numbers

5 The evolution of insurance markets

The global insurance market has historically segmented itself into various categories such as marine, aviation, casualty (general liability, professional negligence, directors and officers liability etc), energy, and property.

The property market is split into two areas - one being general property, which largely excludes the risk of mechanical and electrical breakdown, and there is a specific market within the property market that addresses power utilities business. The property risks for EDBs can fall within the general property market and the specialist power utilities market.

All onshore (land-based) property risks in New Zealand are dominated by the natural disaster exposure. New Zealand insurers have historically been the most competitive at providing insurance for these risks and as a result since around 2002 New Zealand EDBs (including Orion) have bought their property insurance (excluding overhead lines and underground cables) within the New Zealand property insurance market.

During the decade up until 2001 the property insurance markets in New Zealand became very competitive and additionally there was a broadening of the cover that was offered under MD policies. The power utilities market became strained and hardened in 2002 following a number of industry losses, including a number of large business interruption claims .

Wider policy coverages and lower pricing became much more difficult to place after the World Trade Centre event in September 2001. Coverage became more restricted as underwriters sought to gain more control over the risks they were insuring and prices increased markedly - in a number of cases by as much as 300%.

Underwriting of insurance is different for each insurance company, which can result in different pricing of risk. Rating and pricing is not linear or necessarily mathematical. Insurers have different overheads, and their costs and structure of catastrophe (natural disaster) insurance varies - this means an actual "market" exists for insurance. These comments apply globally.

Capacity and pricing in the insurance market is generally impacted by losses, increases or reductions in natural disasters, increases or reductions in profitability, an ability or otherwise to make investment profits on loss reserves and fee capital, and the availability of capital.

In recent years insurance underwriters generally, with influence from credit rating agencies, have put a lot more effort into identifying all the risks they are actually insuring under policy wordings and it is now fair to say they have a much better understanding of those risks. The effect of this is that the larger natural disasters after 2001 (for example - the 2004 and 2005 hurricanes in the Gulf of Mexico, the Canterbury and Japan earthquakes and floods in Thailand) (with a few exceptions, like AMI) did not impact the capital base of the insurance industry, even if they did certainly impact the industry's profitability. The New Zealand insurance market became very "hard" (ie more expensive) in 2011/2012. On the other hand, the World Trade Centre disaster did impact the capital base of a number of insurers and this resulted in some credit rating downgrades.

In summary, the insurance industry is now better able to withstand cumulative natural disasters in any one calendar year. This does not mean there will be no price increases but the capital security of the insurers is generally speaking better founded than has been in the past.

In the context of T&D insurance, it is still difficult to find insurers who are prepared to provide insurance for EDBs with acceptable terms and conditions – including reasonable deductibles and price. T&D insurance is possibly available for some transmission companies who have a large spread of risk and a record of low or no losses, at deductibles that these larger enterprises can tolerate, but this does not translate into similar acceptable insurance being available to EDBs.

6 The forecast evolution of relevant insurance markets

Marsh expects there to be little change in the next few years to insurers' views of natural disaster risks in New Zealand, the availability of such insurance and the pricing of the insurance if it is offered. Generally Marsh expects there to be some softening (lowering) of pricing over time for attractive risks but insurers' current pricing for natural disaster risks will continue for the next few years.

Marsh expects EDBs to continue to look at alternative ways of financing the exposure to their T&D risks from natural disaster losses and insurance brokers will continue to monitor the situation to look for opportunities to develop innovative solutions for this in New Zealand.

Clearly, the Canterbury earthquakes have worsened the MD/BI insurance situation for all New Zealand EDBs – and Orion in particular. They have also worsened the insurance situation for all buyers of property and loss of revenue insurance in New Zealand.

7 Strategies to manage risk transfer

As shown in the credentials section later in this report, Marsh represents many if not most of the significant energy businesses in Australia and New Zealand region.

We are not aware of any EDB in Australasia that has achieved any effective and material risk transfer for the bulk of its T&D assets. This view is in respect of all Marsh clients in the region.

We are aware of only one transmission company in Australia, Powerlink in Queensland, that purchases such insurance.

EDBs' substations, other buildings and contents can be and are insured under standard MD insurance policies at rates that reflect the individual risks of the properties in the geographies in which they are located.

8 Captive insurance and mutual group funding

From time to time over the past eleven years captive insurance companies have been raised as a possible option or vehicle for entities to fund and/or insure their risks.

Captive insurance companies generally work as follows:

- a captive is an insurance subsidiary company - wholly owned by the parent company
- the captive insures specified risks of the parent and/or group and charges a premium for that service
- capital is paid by the parent to establish the captive, interest may be charged and a level of return may be expected
- risk is capped at predetermined levels and is funded by the premiums charged and by the paid-up capital
- as reserves increase, the risk carried by the captive can be increased
- the first years are critical as the risk is generally funded more by capital than premium until the retained earnings and annual premium are adequate to fund the exposure carried by the captive. There are also solvency considerations in the context of the domicile in which the captive is located which will impact the level of capital required - some countries have specific captive enabling legislation and regulation and as a result some domiciles (countries) are easier to work in than others. Compliance with New Zealand insurance legislation and regulation makes New Zealand a challenging environment in which to establish a captive.

Captives' main cited advantages versus just purchasing insurance are usually:

- where a company's risk profile is better than its industry average and/or it expects that its risk management practices will result in improved loss experience
- where a company believes it can reduce its cost of insurance
- the ability to access reinsurance markets directly and thus gain wholesale reinsurance prices
- to provide a cash buffer in the captive to reduce premiums paid to the insurance market
- a captive can be used as a tailor made risk management tool.

Their main disadvantages are usually:

- establishment costs
- ongoing costs such as consultants
- compliance in New Zealand
- corporate governance
- executive time.

In the context of Orion and EDBs generally, we do not believe that captives are appropriate for the following reasons:

- captives are generally not suited to carry catastrophe risks because such risks are difficult to manage and can "limit" losses up to the maximum amount of the insurance provided
- building a cash fund in the captive over time to firstly fund a deductible and then to fund higher proportion of natural disaster risks is a legitimate strategy, albeit with considerable

administrative cost, but without T&D reinsurance support it is not economically feasible because of the large amounts exposed.

- captives can be complex and costly – economies of scale count and Orion is arguably not large enough to justify this complexity and cost
- catastrophe insurance for T&D is not available in the market anyway (especially post the Canterbury earthquakes) and so Orion would not achieve material risk transfer, the whole point of insurance.

The concept of a mutual insurance group involving several or all 29 EDBs in New Zealand has also been considered on more than one occasion over the past eleven years. These considerations have not developed beyond discussion for a number of reasons:

- the different risk profiles of EDBs' networks creates significant issues for individuals EDBs' premiums, deductibles and loss sharing. Urban networks have different risk profiles to rural (largely overhead) networks. Some have greater underground exposure and some greater overhead.
- Orion and some others have spent considerable amounts to improve the resiliency and risk profiles of their networks over the past decade (which paid dividends for Orion and its customers in the recent earthquakes) – some EDBs haven't
- different networks present different exposures to natural disasters such as earthquakes. Natural disaster insurance for T&D risks is not available for networks in Wellington and Christchurch nor probably elsewhere in New Zealand.
- different EDBs have different risk appetites. Most EDBs want lower deductibles than the minimum (circa \$5m) that was available before the Canterbury earthquakes
- the mutual insurance group would still need to be able to purchase natural disaster insurance for all participating members to achieve risk transfer
- the members would have to identify an equitable mechanism for funding losses under the attachment point of any available T&D insurance. Issues of cross subsidisation and replenishing the uninsured part of the "insured" risk were issues for some network companies in the past.

All in all – we believe that if EDBs were to consider a mutual (possibly captive) group to arrange T&D catastrophe cover there would be a significant risk that:

- the interests of EDB members would not be aligned – for example how would Orion's risks (Christchurch's seismicity is greater than average) be priced within the group?
- the costs and complexities (and potential for conflict) would be considerable
- effective and material risk transfer would not be achieved.

9 Orion's approach to MD and BI insurance

Marsh believes that Orion's approach to insurance has been:

- consistent over time
- subject to due process and due governance oversight
- appropriate, prudent and reasonable for the business and its economically insurable MD and BI risks
- consistent with other New Zealand and Australian EDBs.

Although, outside the scope of this report, Marsh also believes that the same positive attributes apply to the other aspects of Orion's insurance programme – for example Orion's liability insurance policies such as general liability and professional indemnity.

Future opportunities for Orion to obtain meaningful T&D catastrophe insurance will depend on the insurance market. Markets can be cyclical and MD and BI cover may become available at a reasonable cost and with acceptable deductibles.

However, we believe that such a favourable change in the insurance market is most unlikely for Orion (Christchurch and central Canterbury) and EDBs generally in the foreseeable future.

Orion will probably be restricted to at best insuring its corporate buildings and key substations under its standard MD policy at highly restricted terms (significant per site deductibles, earthquake claim caps and so on). These insured assets combined make up less than 20% of Orion's asset base (at replacement value).

The bulk of Orion's assets – underground cables and overhead lines (up to 60% or more of Orion's assets) – will effectively remain economically uninsurable and uninsured for the foreseeable future.

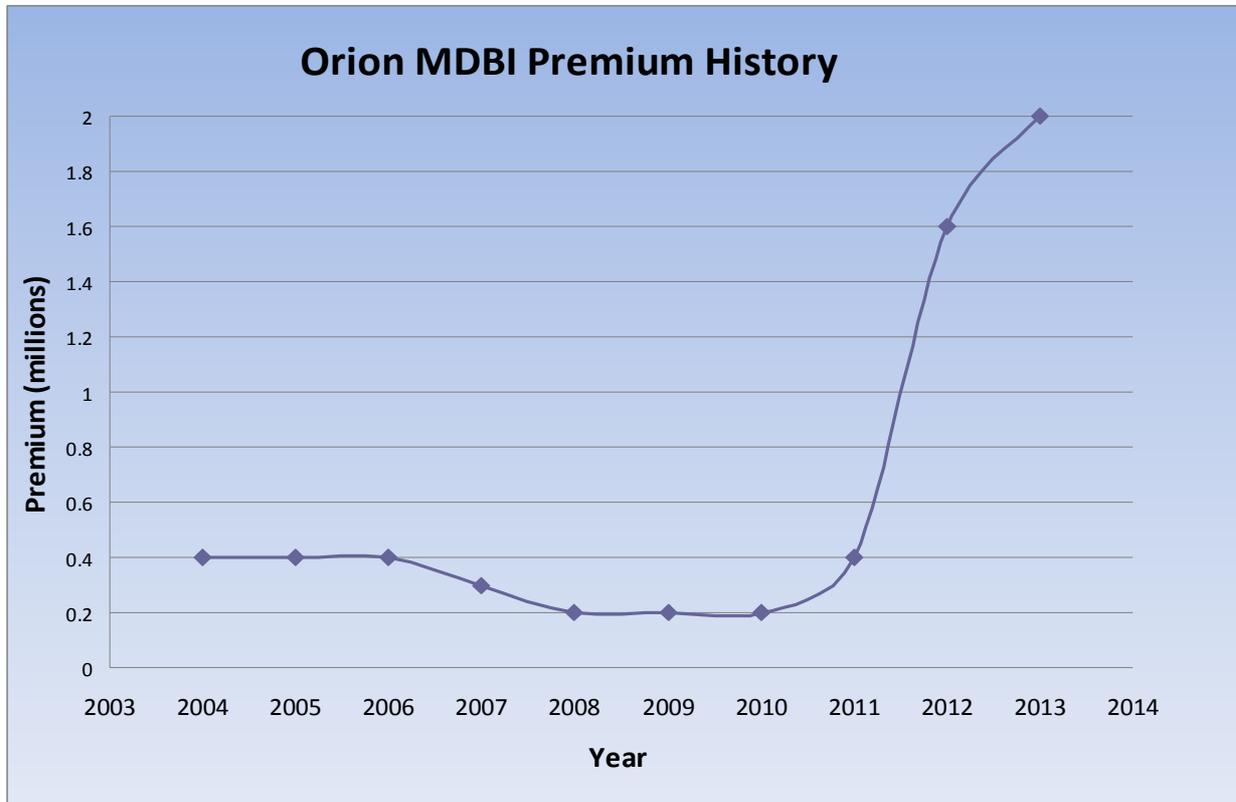
Since the 4 Sep 2010 and 22 Feb 2011 earthquakes, Orion's MD/BI insurers have:

- massively increased annual premiums at renewal dates (from a market low point of \$0.2m on 1 Oct 2009 to \$2.0m on 1 Oct 2012)
- introduced "per site" deductibles for earthquakes for the first time for Orion (10% for post 1935 buildings but 15% for pre 1935) effectively equivalent to Wellington rates – previously Orion had just one combined MD/BI natural disaster deductible for Orion and Connetics of \$0.75m
- introduced a \$100m annual cap on Orion's natural disaster related claims – previously Orion's effective cap for substations and its head office buildings was around \$300m
- retained a \$70 network delivery revenue claim cap
- reduced Orion's BI indemnity period to 12 months (previously 18 months).

In late September 2012 Orion's board approved its insurance renewals for its insurance policies for the year commencing ending 30 September 2012.

In the current market, it was not feasible for Orion to seek competitive quotes. Virtually no insurer is offering new MD/BI business in Canterbury right now – and certainly not for T&D risks.

A chart of Orion’s MD/BI premiums over the last decade is as follows (annualised, years ending 30 September):



This chart clearly shows the cyclical nature of the insurance market (for example, premiums halved between 2006 and 2008) and the impact of the Canterbury earthquakes. Orion has insured its key substations and its corporate properties throughout this period.

10 Network owners' future approach

The current approach in our region (insured key substations under MD/BI) has been the norm for over a decade. Marsh does not expect any material softening or change in the insurance market that will trigger a material change to this approach in the future.

11 Catastrophe insurance claims can be complex

It's useful to understand Orion's earthquake claims experience so far.

Catastrophe claims, and especially Canterbury earthquake claims are time consuming and complex for all concerned. However we believe that Orion is managing its claims process in a very professional manner and that Orion and its insurers are making good progress in resolving those claims.

Orion's largest MD/BI claims relate to:

- Orion's CBD offices and ancillary buildings on its CBD site and their respective contents – Orion has cash settled with insurers for over \$20m for these and the offices and one of the ancillary buildings have been demolished
- Orion's Brighton zone substation – this substation in the eastern suburbs was damaged but the actual equipment largely survived; it and another smaller substation needed to be relocated 1.5km away at Rawhiti Domain. This is a very complex MD and BI claim, which is currently in discussion with insurers.
- Orion's other damaged substations
- Orion's increased costs of working – capped at \$5m and they need to be due to physical damage to Orion's insured property.

We understand that Orion has experienced a significant drop in its network delivery revenues. The majority of that reduction in revenue has been caused by uninsured events such as:

- depopulation
- damage to Orion's underground 11kV cables in the eastern suburbs.

The BI insurance that Orion was able to purchase will provide very little contribution to the total reduction in revenue suffered by Orion..

We expect that Orion's earthquake MD and BI claims process will continue well into next year.

12 Marsh credentials

The author of this report is Paul Casey, Executive Director of Marsh Limited New Zealand. Paul's credentials are as follows:

- Previously Power Utilities Practice Leader at Marsh New Zealand
- Previously client executive to Contact Energy (programme moved to Australia some years after Origin gained control)
- Manager the TRIP scheme at Marsh from 1999 to 2001
- Client executive to Transpower New Zealand Limited from 2004
- Previous client executive to United Networks now part of Vector
- Overview role with Vector over a number of years when it was a Marsh client.
- Over 30 years insurance broking experience providing risk and insurance broking services to companies in New Zealand and Australia
- Global Client Executive at Marsh for Fonterra Cooperative Group Limited from 2007.

Marsh has a team of dedicated power, gas, and water utility specialists in New Zealand, Australia, Asia, USA and Europe. Marsh has substantial market share in this area with specialists providing client advisory, risk consulting and insurance programme marketing and placement services to these industries.

Marsh has been Orion's insurance broker since 1998.

Marsh in New Zealand acts for 36% of the top 100 companies and holds a similar position in Australia. In both countries and arguably globally Marsh is the leader in power utilities business.

The following list of Marsh energy industry clients demonstrates the level of acceptance our expertise has in this sector in Australia and New Zealand.

NEW ZEALAND			
Entity	Business	Entity	Business
Mighty River Power	Generator/Retail	Meridian Energy	Generator
Transpower New Zealand	Transmission	Marlborough Lines	Distribution
Delta Energy	Generator	Nelson Electricity	Distribution
Mighty River Power	Generator/Retail	Orion	Distribution
Power Co	Distribution	Horizon Energy	Distribution
Eastland Networks	Distribution	Marlborough	Distribution
Nelson Electricity	Distribution	Mainpower	Distribution
Alpine Energy	Distribution	Network Waitaki	Distribution
OtagoNet	Distribution	PowerNet	Distribution
Todd Group	Generator		Distribution
Electricity Authority		Energy Networks Association	

VICTORIA			
Entity	Business	Entity	Business
TRUenergy	Generator	IPower	Retailer
Hazelwood Power	Generator	Vemco	Vegetation Mgt
Loy Yang B	Generator	Basslink	Transmission
Loy Yang Power	Generator	Toora	Wind Farm
Gas Pipelines Victoria	Transmission	Oaklands Hill	Wind Farm
United Energy Distribution	Distributor	Macarthur	Wind Farm
MultiNet Group – Gas	Distributor		
NEW SOUTH WALES			
Entity	Business	Entity	Business
Country Energy	Distributor	DirectLink	Transmission
Delta Electricity	Generator	AGL	Generator
Eraring Energy	Generator	Murubeni Power Development	Co-Generator Plant
Smithfield	Generator	APT	Gas Transmission
Actew/AGL	Distributor/ Retail	Capital Wind	Wind Farm
QUEENSLAND		WESTERN AUSTRALIA	
Entity	Business	Entity	Business
Stanwell Corporation	Generator	Newgen Power Kwinana Partnership	Generator
Condamine Power Station	Generator		
Powerlink Queensland	Transmission	NewGen Neerabup Power Station	Generator
Oakey Power	Generator	Kemerton Power Station	Generator
Collinsville Power Station	Generator	Collgar	Wind Farm
Townsville Power Station	Generator	Alinta	Wind Farm
Windy Hill	Wind Farm		
SOUTH AUSTRALIA		TASMANIA	
Entity	Business	Entity	Business
International Power (Australia)	Generator	Hydro	Generator
ElectraNet	Transmission	Transend	Transmission
Infratil	Generator	Aurora Energy	Retail/Distribution

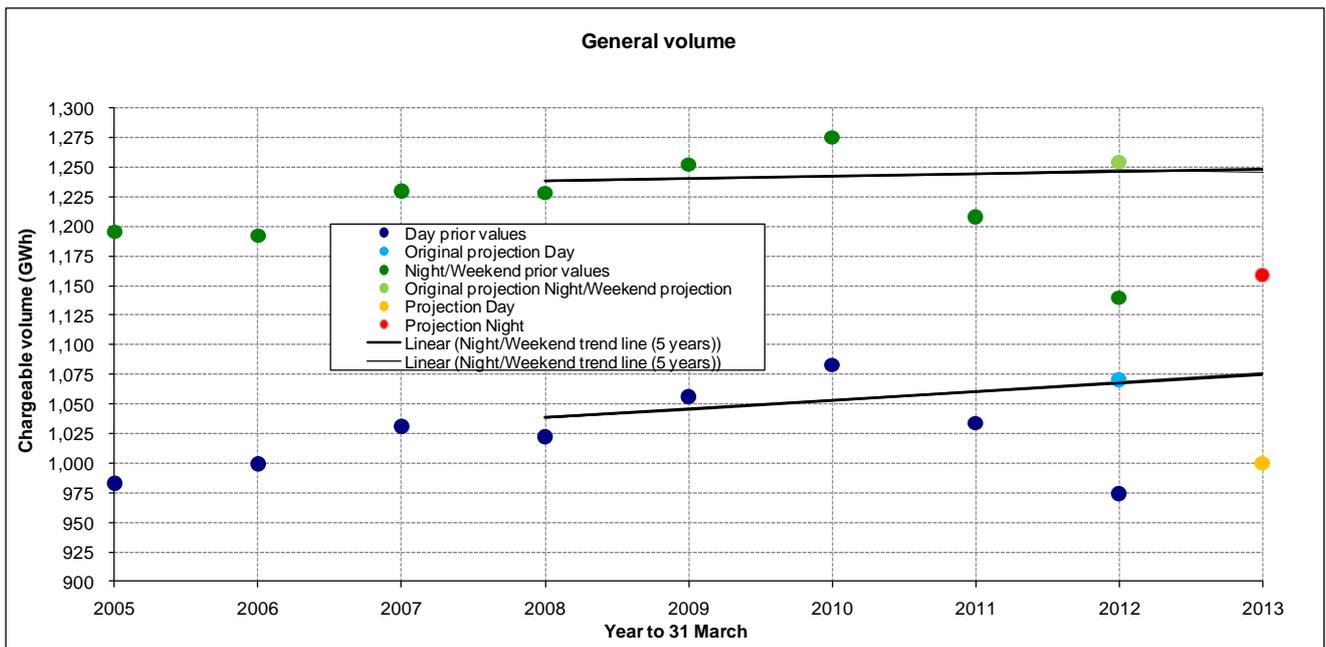
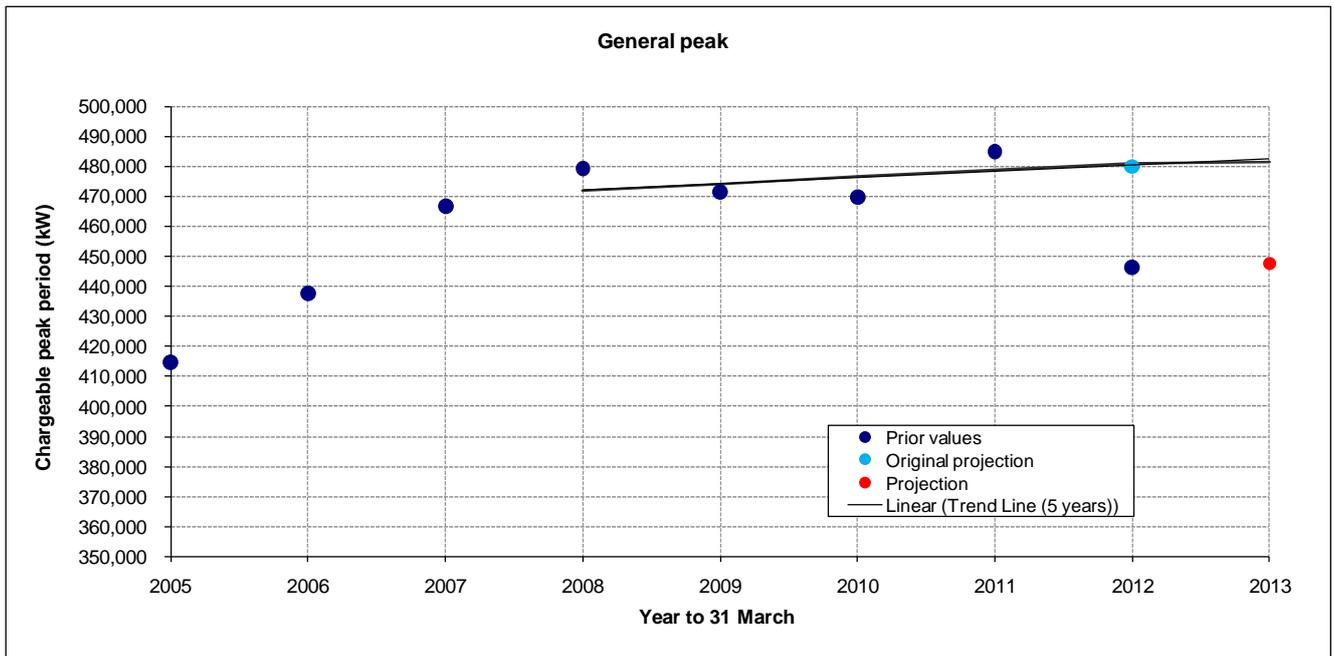


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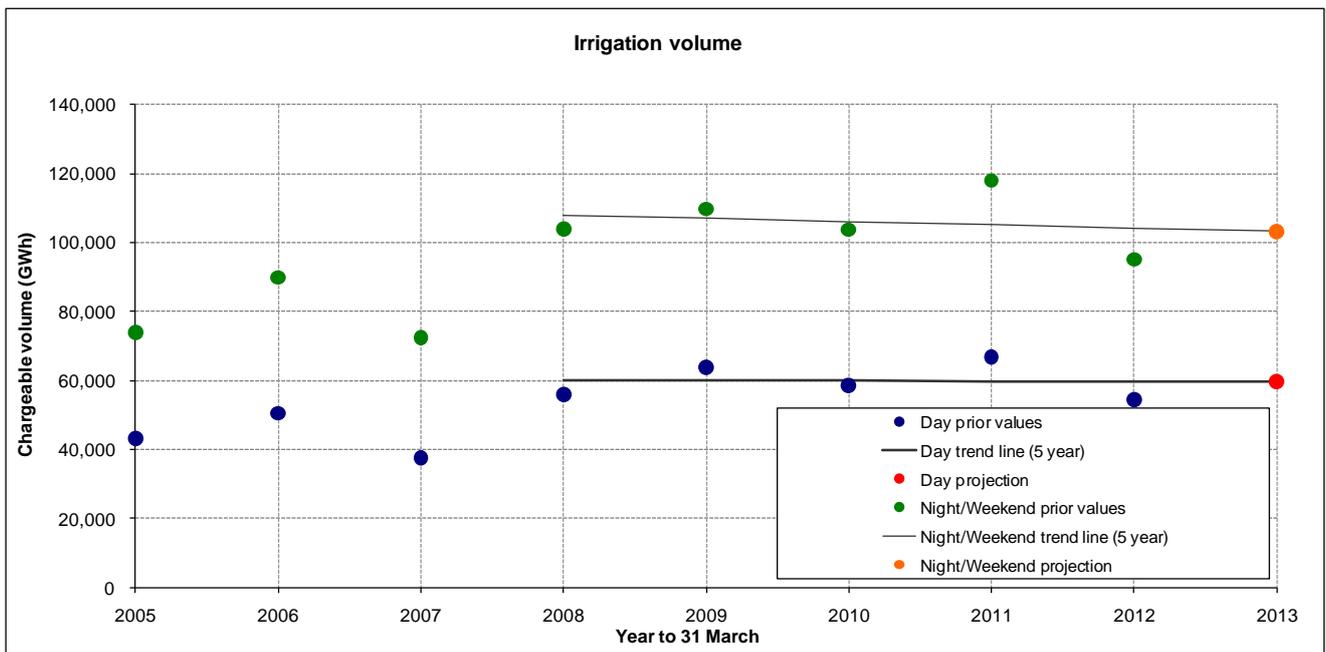
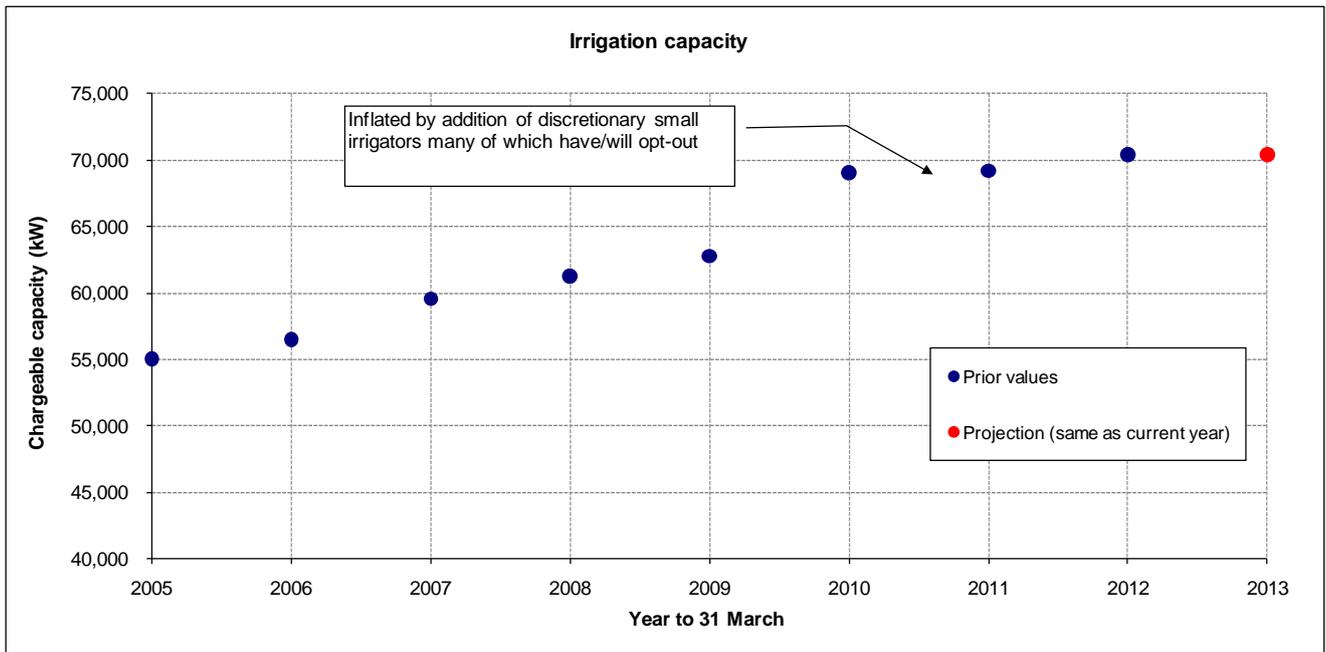
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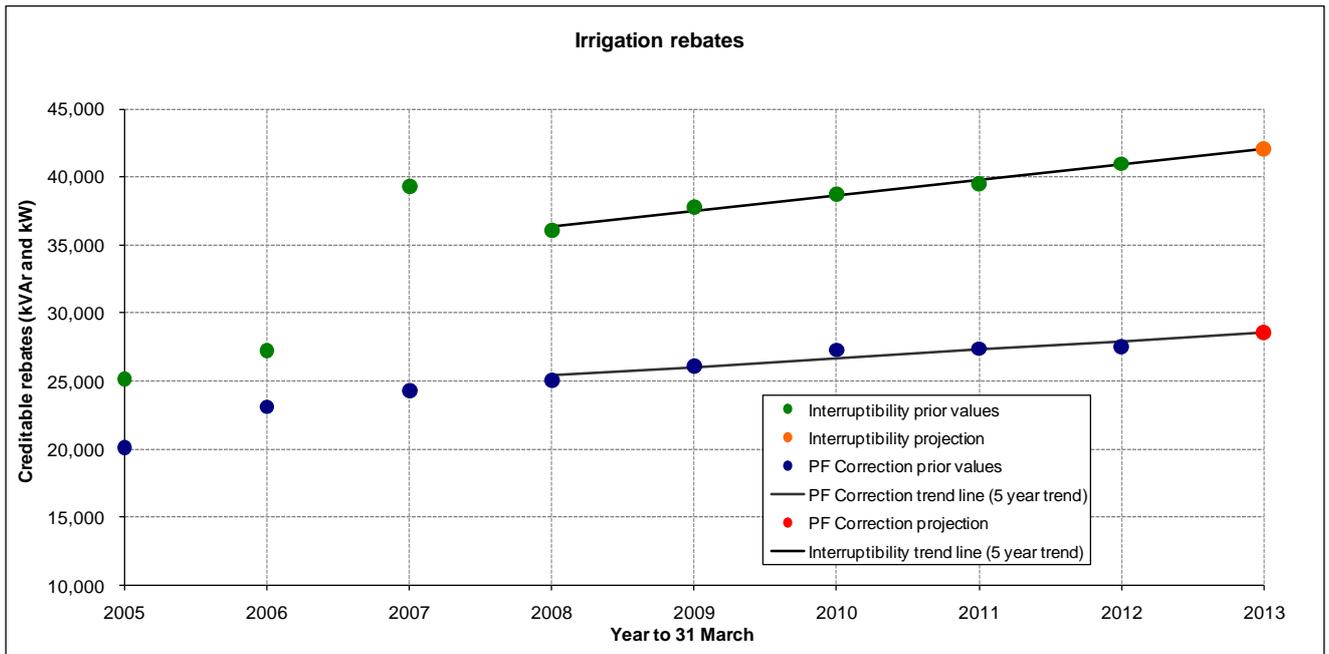
Quantity growth trends

General connections

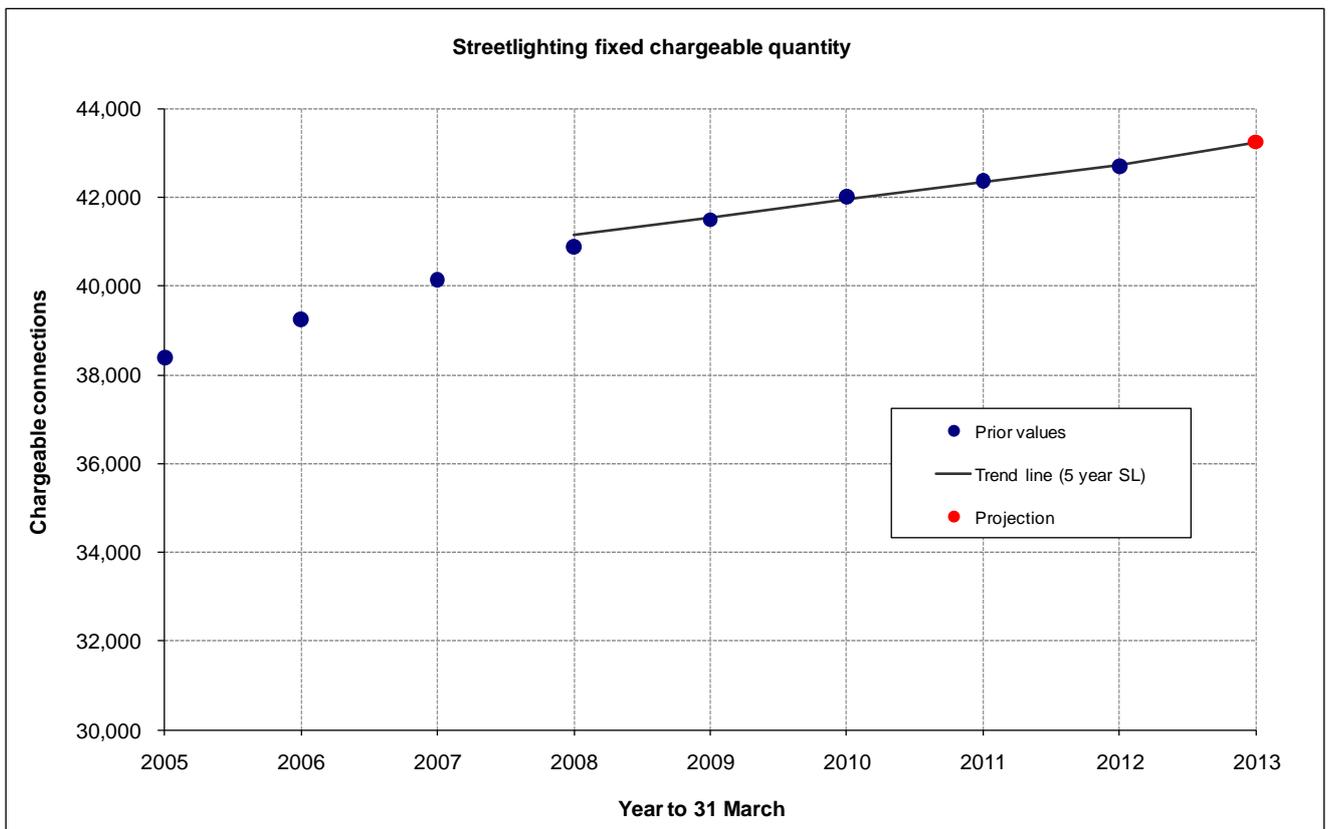


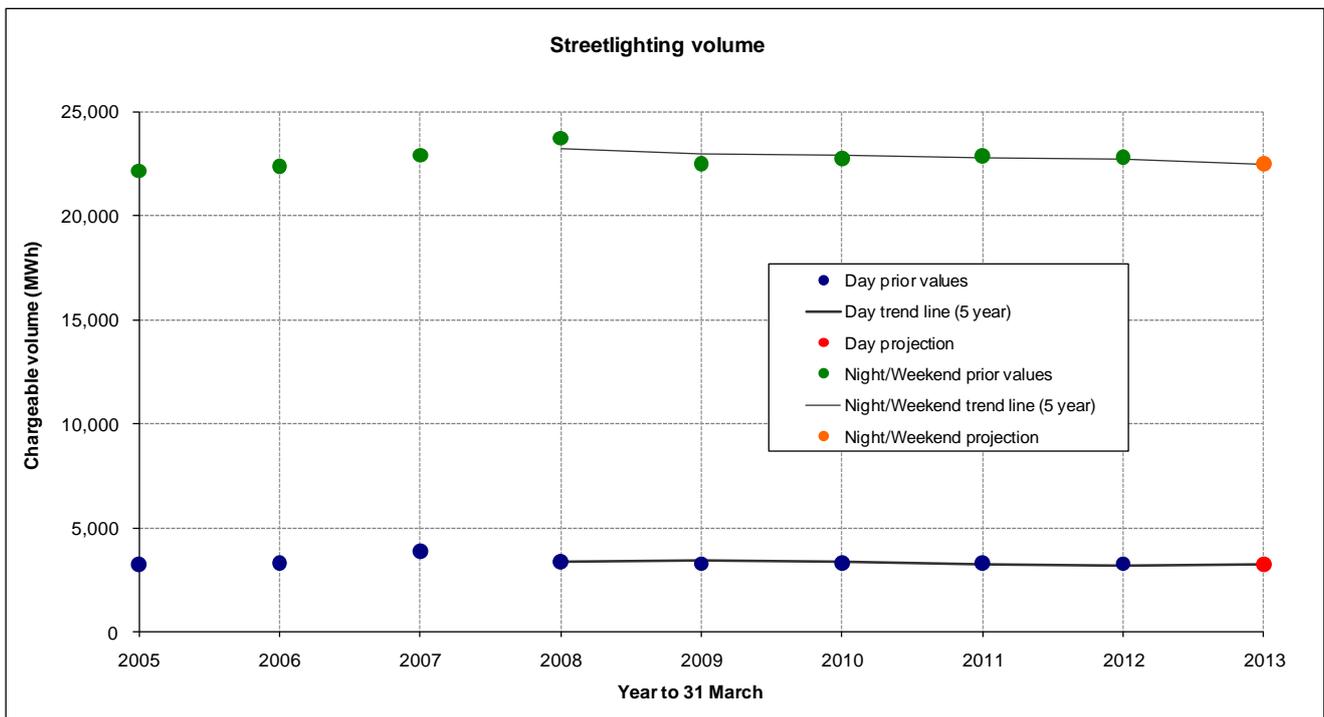
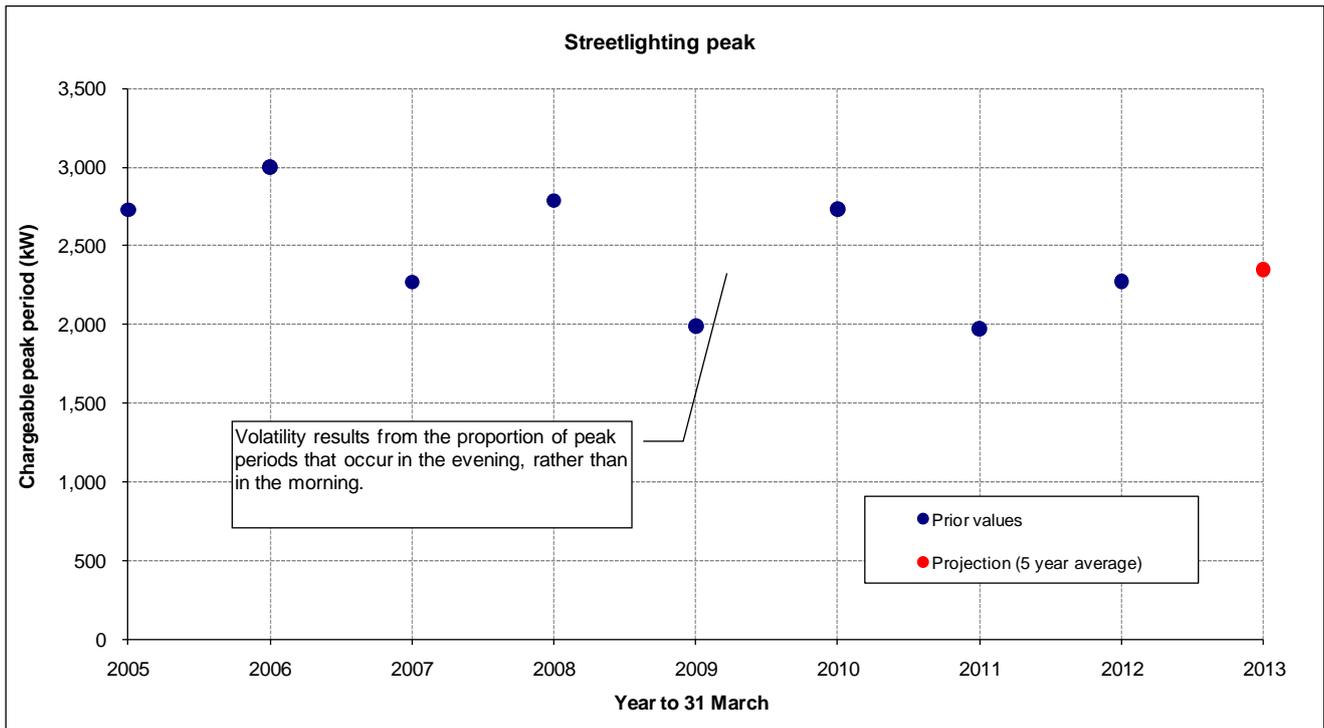
Irrigation connections





Street lighting connections





Appendix 13

Detailed calculations for weighted average growth in quantities

Detailed calculations for weighted average growth in quantities

IM 5.4.8(5)

This appendix contains additional information related to the forecast weighted average growth in quantities, as discussed in Section 7.2.5 of the proposal.

Historical quantities for FY05 to FY12

The table below shows historical quantities, from FY05 to FY12, for each charge.

Historical quantities for each consumer group by charge type								
	FY05	FY06	FY07	FY08	FY09	FY10	FY11	FY12
General connections								
Peak charge (kW)	414,626	437,684	466,538	479,290	471,481	469,853	484,724	446,363
Volume charge: working weekdays (MWh)	982,940	999,562	1,031,331	1,021,961	1,056,117	1,082,974	1,033,761	974,117
Volume charge: nights, weekends, holidays (MWh)	1,195,614	1,192,348	1,229,876	1,228,087	1,252,408	1,275,326	1,207,887	1,139,712
Low power factor charge (kVAr)	101	101	101	101	101	0	0	0
Major customer connections								
Fixed charge: standard connections (connections)	390	395	395	395	410	408	416	366
Fixed charge: secondary connections (connections)	18	18	17	17	17	17	16	14
Fixed charge: dedicated equipment (by item \$000)	1,287,000	1,301,000	1,298,421	1,298,820	1,719,374	1,748,476	1,819,638	1,654,000
Peak charge (kVA)	112,189	122,361	122,589	118,251	115,943	124,192	116,648	107,898
Capacity charge (kVA)	204,723	212,142	212,413	209,390	211,683	212,797	210,496	201,250
Irrigation connections								
Capacity charge (kW)	55,033	56,493	59,549	61,278	62,766	68,609	69,213	70,446
Volume charge: working weekdays (MWh)	43,087	50,481	37,627	56,049	63,920	58,440	66,719	54,359
Volume charge: nights, weekends, holidays (MWh)	73,941	89,879	72,377	104,020	109,647	103,755	117,920	95,063
Rebate: power factor correction (kVAr)	20,124	23,105	24,296	25,029	26,094	27,293	27,387	27,530
Rebate: interruptibility (kW)	25,129	27,220	39,299	36,083	37,785	38,763	39,510	40,964
Street lighting connections								
Fixed charge (connections)	38,399	39,245	40,135	40,896	41,500	42,016	42,375	42,707
Peak charge (kW)	2,730	3,000	2,271	2,787	1,990	2,736	1,971	2,274
Volume charge: working weekdays (MWh)	3,241	3,328	3,889	3,390	3,290	3,301	3,309	3,279
Volume charge: nights, weekends, holidays (MWh)	22,173	22,405	22,926	23,731	22,532	22,757	22,900	22,810
Large Capacity - Fonterra								
Administration charge (kVA)	-	-	-	-	-	-	-	-
Use of distribution assets (kVA)	-	-	-	-	-	-	-	-
Lareg capacity - Synlait								
Administration charge (kVA)	-	-	-	-	4,800	3,058	3,445	5,800
Asset charge (kVA)	-	-	-	-	-	-	-	5,800
Export and generation								
Real power distribution component (kW)	3,171	2,277	3,747	4,036	3,241	3,130	2,649	2,104
Reactive power distribution component (kVAr)	1,681	2,251	2,517	2,545	2,217	1,937	1,710	1,127
Generation credits (kWh)	-	-	8,262	40,721	65,423	357,450	307,554	422,808

Reconciliation between DPP revenue quantities and CPP quantities

The two tables below reconcile the FY10 quantities used in this CPP proposal and those from our current DPP. The first table shows the quantities in FY10 for each charge. These are used to help derive our forecast quantities for each charge. The second table shows the assessed DPP quantities for FY10.

CPP Quantities			
Components	Units	Actual 09/10	References
Streetlighting connections			
Fixed charge	Connections	42,016	a
Peak charge (peak period demand)	kW	2,736	to b
Volume charge			
Working weekdays (7am - 9pm)	MWh	3,301	to c
Nights, weekends and holidays	MWh	22,757	to d
General connections			
Peak charge (peak period demand)	kW	469,853	to b
Volume charge			
Working weekdays (7am - 9pm)	MWh	1,082,974	to c
Nights, weekends and holidays	MWh	1,275,326	to d
Low power factor charge	kVAr	-	e
Irrigation connections			
Capacity charge	kW	68,609	f
Volume charge			
Working weekdays (7am - 9pm)	MWh	58,440	to c
Nights, weekends and holidays	MWh	103,755	to d
Rebates			
Power factor correction rebate	kVAr	27,293	g
Interruptibility rebate	kW	38,763	h
Major customer connections & Embedded networks			
Fixed charge			
Fixed (Standard connections)	Connections	408	i
Fixed (Secondary connections)	Connections	17	j
Dedicated Equipment	By item (\$000)	1,748,476	
Peak charge (control period demand)	kVA	124,192	k
Capacity charge			
Assessed capacity distribution	kVA	212,797	l
Assessed capacity transmission	kVA	227,952	n/a
Large capacity connections (Synlait)			
Distribution charge			
Administration	kVA	3,058	m
Asset Charge		35%	n
Transmission charge			
Interconnection charge (winter)	kVA	607	n/a
Interconnection charge (summer)	kVA	3,058	n/a
Use of transmission connection assets		4%	n/a
Large capacity connections (Fonterra) - no charge in 2010 and hence there are no quantities			
Distribution charge			
Administration	kVA		
Use of distribution assets	kVA		
Transmission charge			
Interconnection charge (winter)	kVA		
Interconnection charge (summer)	kVA		
Use of transmission connection assets	kVA		
Export and generation			
Real power distribution component	kW	3,130	p
Reactive power distribution component	kVAr	1,923	q
Real power transmission component	kW	3,130	n/a
Generation credits	kWh	357,450	r
Grouping streetlight, general and irrigation	Units	Actual 09/10	References
Peak charge (peak period demand)			
Streetlighting connections	kW	2,736	
General connections	kW	469,853	
	kW	472,589	b
Volume charge			
Working weekdays (7am - 9pm)			
Streetlighting connections	MWh	3,301	
General connections	MWh	1,082,974	
Irrigation connections	MWh	58,440	
		1,144,715	c
Nights, weekends and holidays			
Streetlighting connections	MWh	22,757	
General connections	MWh	1,275,326	
Irrigation connections	MWh	103,755	
	MWh	1,401,838	d

DPP Quantities - price path assessment as at 31 March 2012

Components	Units	Quantities (Q1,2010)	References
Streetlighting, general and irrigation connections			
Streetlighting fixed charge	Connections	42,016	a
Streetlighting and general connections			
Peak charge (peak period demand)	kW	472,589	b
Streetlighting, general and irrigation connections volume charge			
Working weekdays (7am - 9pm)	MWh	1,144,715	c
Nights, weekends and holidays	MWh	1,401,838	d
General connections			
Low power factor charge	kVAr	-	e
Irrigation connections			
Capacity charge	kW	68,609	f
Power factor correction rebate	kVAr	27,293	g
Interruptibility rebate	kW	38,763	h
Major customer connections			
Fixed charge			
Fixed (Standard connections)	Connections	408	i
Fixed (Secondary connections)	Connections	17	j
Peak charge (control period demand)	kVA	124,192	k
Capacity charge			
Assessed capacity distribution	kVA	212,797	l
Assessed capacity transmission	kVA	227,653	n/a
Large capacity connections (Synlait)			
Distribution charge			
Administration	kVA	3,058	m
Use of distribution assets		35	n
Transmission charge			
Interconnection charge (winter)	kVA	607	n/a
Interconnection charge (summer)	kVA	3,058	n/a
Use of transmission connection assets		4	n/a
Export and generation			
Real power credit	kW	3,130	p
Reactive power credit	kVAr	1,923	q
Generation credit	kWh	357,450	r

Appendix 14

SKM's Report on Initial RAB Adjustments

Independent Engineer's Report on the Asset Adjustment Process of: Orion NZ Ltd

- 9 October 2012



Independent Engineer's Report on the Asset Adjustment Process of: Orion NZ Ltd

■ 9 October 2012

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Contents

Executive Summary	1
1. Introduction	2
1.1. Background	2
1.2. Processes	2
2. Information Provided by Orion	3
3. Consideration of RAB Adjustments	4
3.1. Load Control Relays	4
3.2. Correct Asset Register Errors	4
3.3. Reapplication of Asset Multipliers	4
3.4. Reapplication of Existing or Modified Multiplier Types	4
3.5. Re-apply Optimisation and/or Economic Value Test	5
3.6. Re-categorisation of Assets	5
4. Roll-forward 2005-2009	6
4.1. Asset Re-categorisation Adjustment	6
5. Summary	8
Appendix A Table Summary of Asset Value Adjustments: Schedule A4	9
Appendix B Orion Instructions to Engineer	10
Appendix C Signed Statement by Engineer	11
Appendix D Initial Regulatory Asset Base as at 31 March 2009	12



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GLOSSARY

EDB	Electricity Distribution Business
DRC	Depreciated Replacement Cost
EDB IM	Electricity Distribution Services Input Methodologies
GIS	Geographic Information System
ODRC	Optimised Depreciated Replacement Cost
ODV	Optimised Deprival Valuation
ORC	Optimised Replacement Cost
RAB	Regulatory Asset Base
RC	Replacement Cost
SKM	Sinclair Knight Merz



Executive Summary

On 22 December 2010 the Commerce Commission (Commission) released a document entitled “*Commerce Act (Electricity Distribution Input Methodologies) Determination 2010*” (EDB IM). The EDB IM outlines a set of modifications (referred to as the “asset adjustment process”) that Electricity Distribution Businesses (EDBs) may choose to undertake to their disclosed 2004 ODVs as part of the process to establish an Initial Regulatory Asset Base (Initial RAB) as defined in clause 2.2.2 of the EDB IM.

On 27 August 2012 Orion New Zealand Limited received, from the Commission, a “*Notice to supply information to the Commerce Commission Section - 53ZD of the Commerce Act 1986*” (Section 53ZD Notice). Associated with this Section 53ZD Notice was the requirement that Orion supply an independent Engineer’s Report in respect of the asset adjustment process used for setting its Initial RAB. The exact requirements of this report are contained in “Schedule E: Information Requirements for Engineer’s Report” of the Section 53ZD Notice.

Sinclair Knight Merz (SKM) was requested by Orion to review changes made to the initial RAB and confirm that they meet with the requirements of the asset adjustment process outlined in Clause 2.2.1 of the Commerce Commission’s EDB IM. In particular, to review adjustments Orion has made that relate to clause 2.2.1(2)(b) where post 1 April 2004 additions have been re-categorised for the purpose of calculating depreciation by assigning the appropriate standard physical asset lives. These adjustments have been made in order to comply with the asset classes outlined in Schedule A of the EDB IM.

SKM has reviewed the re-categorisation of asset additions for the period 2005-2009 and deems the judgements and assumptions applied to be reasonable. SKM has not undertaken a detailed audit of the value assigned to each sub-category, as this is the responsibility of Orion’s auditors (Audit NZ).

No adjustments to assets existing at 2004 were made by Orion.

The following table summarises the adjustments arising from Orion’s proposed additions and deletions relating to the period 2005 through 2009 (year ending 31 March).

Year	2004	2005	2006	2007	2008	2009
Value of Adjustments (ODV)	\$0.0k	\$0.2k	(\$65.7k)	(\$134.4k)	(\$194.7k)	(\$357.8k)



1. Introduction

1.1. Background

Sinclair Knight Merz Ltd (SKM) was requested by Orion New Zealand Limited (Orion) to undertake an independent review of its asset adjustment process. SKM's review was undertaken to determine the appropriateness of the proposed adjustments in respect of the asset adjustment process as set out in clause 2.2.1 of the "Commerce Act (Electricity Distribution Services Input Methodologies) Determination 2010", 22 December 2010 (EDB IM).

This report details the findings of the independent review and has been prepared to comply with the requirements for the independent Engineer's Report in Schedule E of the Commerce Commission's "Notice to supply information to the Commerce Commission Section 53ZD of the Commerce Act 1986 (Section 53ZD Notice), dated 27 August 2012. A copy of the signed statement required by the Section 53ZD Notice is provided in Appendix C.

SKM notes that Orion does not propose to make any adjustments to the 2004 ODV, which typically comprises of the following items: the inclusion of load control relays; corrections for asset errors; the reapplication of asset multipliers; and the reapplication of optimisation or economic value.

The EDB IM also allows for changes to be made under the asset adjustment process to those assets allocated to the incorrect asset category, or given an estimation of quantity, age, category or locations now know to be incorrect, which assets are designated as of "value modified" type.

Orion has proposed to correct the classification of some of its assets in its valuation database with the result that some small adjustments are required to the RAB particularly in relation to depreciation over the 2005-2009 period.

SKM has focused principally on the methodology that Orion has used to its re-categorise assets.

1.2. Processes

The preparation of this report has been the responsibility of SKM. SKM has relied upon information and data prepared by Orion. Wherever possible we have sought to verify this data to check its validity including liaising with Orion's staff. SKM has not conducted field /site visits to confirm the accuracy of Orion's asset management systems. In the interests of accuracy and completeness, there has been interaction between SKM and Orion during the review. This has been undertaken via telephone discussions and email correspondence.



2. Information Provided by Orion

Orion supplied SKM with a number of documents and files to support the review, as follows:

- *“Initial Regulatory Asset Base as at 31 March 2009”*, Orion report issued 9 October 2012. [see Appendix D]
- *“Regulatory Valuation Register”*, MS-Access database populated from the company’s asset management systems/databases.
- *“Orion 2004 ODV Asset Schedules report”*
- *“Orion Report on Optimised Deprivation Valuation of System Fixed Assets as at 31 March 2004”*, dated 7 December 2004.

“53ZD Notice Schedule A4 (30 August 2012).xls”, MS-Excel file containing breakdown of inputs to Appendix A4 of EDB IM.



3. Consideration of RAB Adjustments

This section considers the basis for adjustments to the Orion 2004 RAB, made under the asset adjustment process.

3.1. Load Control Relays

Reference EDB IM cl 2.2.1(2)(a). An EDB may designate a load control relay asset owned by an EDB, except a 2009 disclosed asset, as of 'included' type. Clause 2.2.1(3) goes on to say that assets to which sub-clause (2)(a) applies may be valued as:

- its depreciated historic cost as at 31 March 2009; or
- if there are insufficient records, then its depreciated carrying value from the general purpose financial statements.

Orion has not included load control relays in its 2004 RAB.

3.2. Correct Asset Register Errors

Reference EDB IM cl 2.2.1(2)(b). EDBs may correct asset related errors in the light of new information. The allowable corrections being due to:

- assets being omitted in error;
- assets being included in error;
- assets being incorrectly categorised; and
- asset ages, quantity, category or locations being incorrectly recorded.

Orion has not identified any errors or omissions in its 2004 RAB requiring correction.

3.3. Reapplication of Asset Multipliers

Reference EDB IM cl 2.2.1(2)(c). EDBs may reapply multipliers where more accurate information has become available.

Orion has not proposed to make any adjustments to its application of multipliers used in its 2004 RAB.

3.4. Reapplication of Existing or Modified Multiplier Types

Reference EDB IM cl 2.2.1(2)(d). EDBs may reapply the multiplier types (rugged terrain multiplier; business district multiplier; rocky ground multiplier) within the ranges and circumstances specified in the ODV handbook.

Orion has not proposed to make any adjustments to its application of multipliers used in its 2004 RAB.



3.5. Re-apply Optimisation and/or Economic Value Test

Reference EDB IM cl 2.2.1(2)(e). EDBs may reconsider the application of optimisation or economic value testing based on the network conditions during 2009.

Orion has not proposed any optimisation or EV adjustments to its 2004 RAB.

3.6. Re-categorisation of Assets

Orion's report "Initial Regulatory Asset Base as at 31 March 2009, issued 9 October 2012" (a copy of this report is included in Appendix D) sets out the methodology adopted by Orion to correct the allocation of asset additions since 2004 (categorisation corrections) in accordance with Schedule A of the EDB IM and the subsequent changes to the calculation of depreciation from those given in Orion's Electricity Distribution (Information Disclosure) from 2005 to 2009.



4. Roll-forward 2005-2009

4.1. Asset Re-categorisation Adjustment

Over the period 2005 through 2009 Orion recorded asset additions in approximately fifteen different high level asset classes and while these were in accordance with disclosure requirements at the time, they were not necessarily in the form required by Schedule A of the EDB IM.

Orion proposes to re-categorise the additions and deletions, over the period 2005 through 2009, into asset categories that align with Schedule A of the EDB IM. This, in turn, has impacted on the depreciation that Orion disclosed over the period 2005 through 2009.

Orion's process of re-categorisation has required estimation and engineering judgement. SKM has reviewed Orion's re-categorisation process and specifically notes the following:

- 1) Five of the original Orion general ledger asset classes ("Ripple Injection", "SCADA Equip", "SCADA & ripple software", "Building Kiosks" and "Buildings Pole") have been allocated directly to three of the EDB IM asset classes ((i) Ripple injection plant, (ii) SCADA and communications, (iii) Distribution substations.
- 2) Seven of the original Orion general ledger building & easement asset classes have been allocated into three EDB IM asset classes ((i) Zone substation; site development and buildings, (ii) Distribution substations and (iii) Easements).
- 3) Six of the original Orion general ledger asset classes ("Transformer", "Underground cables", "Overhead lines", "LC Switchgear & misc equip", "HV Switchgear & misc equip" and "Land substations & Kiosk land") have been allocated to align with the EDB IM asset classes. Orion has estimated the proportion of the split by considering historical information that it has access to, for example, Orion's capital expenditure prior to 2004.
- 4) Overhead line additions, over the period 2005-2009, have been based on a wood pole 45 year standard life, whereas overhead lines had previously been depreciated over 49.9 years based on the weighted average of wood and concrete pole used up until 2004). This change is based on the fact that Orion has reassessed its additions/standards and identified that wood pole installations have predominated over the 2005-2009 period.
- 5) XLPE cable additions have been depreciated based on a cable life of 45 years (previously depreciated over 46.7 years) based on the standard life in Appendix A of the ODV handbook and using the 2008 Information Disclosure Requirements.

SKM is of the view that methodology used by Orion to align the asset categorisation of additions / deletions from 2005 to 2009 is reasonable and further that the additions over the period 2005-2009 are assigned the appropriate standard asset lives in Schedule A of the EDB IM. A consequence of the adjustment process is a greater depreciation charge associated with asset additions over the 2005-2009 period (when compared to that previously disclosed).



SKM has not audited the re-categorisation data provided by Orion and has relied on the documentation that has been supplied. Furthermore, SKM understands that the historical costs provided in the roll forward have been reviewed by an accountant and that the roll forward has been subject to an audit by Orion's auditors.

The annual adjustments over the period 2005-2009 are outlined in Table 1.

■ **Table 1 : Additions, Disposals, Depreciation & Revaluation: 2005-2009 period**

Year	Original disclosed	New roll-forward	Annual Difference
2005	\$28,646,000	\$28,646,227	\$227
2006	\$29,543,000	\$29,477,259	(\$65,741)
2007	\$22,737,000	\$22,602,568	(\$134,432)
2008	\$39,397,000	\$39,202,350	(\$194,650)
2009	\$35,219,000	\$34,861,230	(\$357,770)

The total closing values over the 2005-2009 period are outlined in Table 2.

■ **Table 2 : Closing values: 2005-2009 period and cumulative difference**

Year	Original disclosed	New roll-forward	Cumulative Difference
2005	\$608,870,000	\$608,870,227	\$227
2006	\$638,413,000	\$638,347,486	(\$65,514)
2007	\$661,150,000	\$660,950,054	(\$199,946)
2008	\$700,547,000	\$700,152,403	(\$394,597)
2009	\$735,765,000	\$735,013,633	(\$751,367)



5. Summary

Orion proposes to make no changes to its 2004 RAB. Orion has proposed to re-categorise some of the asset additions over the period 2005 to 2009 to correctly identify with Schedule A of the EDB IM. The proposed changes are outlined in Schedule A4 in Appendix A.

Appendix A Table Summary of Asset Value Adjustments: Schedule A4

EDB Name **Orion New Zealand Limited**
 Disclosure Year Ended **31 March 2010**

SCHEDULE A4: ASSET ADJUSTMENT PROCESS

row		2004 *	2005	2006	2007	2008	2009	Ref	
		(\$000)	(\$000)	(\$000)	(\$000)	(\$000)	(\$000)		
6	<u>Summary of Engineer's Valuation Adjustments (at time asset enters regulatory asset register)</u>								
7									
8	Asset adjustment process - adjustments								
9									
10	Include load control relays						nil	2.2.1(2)(a)	
11	Correct asset register errors for 2004 ODV assets								
12	No asset register errors corrected		nil						
13									
14									
15			nil					2.2.1(2)(b)	
16	Correct asset register errors for 2005 – 2009 assets								
17	Depreciation and resulting revaluation differences from recategorisation of 05 to 09 additions								
18	Lines		0	(13)	(26)	(40)	(59)		
19	Cables		0	(24)	(51)	(84)	(132)		
20	Transformers		0	12	14	(27)	(30)		
21	Other assets		0	(42)	(72)	(43)	(135)		
22	Other rounding differences		0	1	(0)	(2)	(2)		
23			0.227	(65.741)	(134.432)	(194.650)	(357.770)	2.2.1(2)(b)	
24	Re-apply an existing multiplier to 2004 ODV assets								
25	No changes to multipliers		nil						
26									
27									
28			nil					2.2.1(2)(c)	
29	Re-apply a modified multiplier to 2004 ODV assets								
30	No changes to multipliers		nil						
31									
32									
33			nil					2.2.1(2)(d)	
34	Re-apply optimisation or EV tests to 2004 ODV assets								
35	No change to optimisation or EV tests								
36									
37									
38			nil					2.2.1(2)(e)	
39									
40	Total value of adjustments by disclosure year		nil	0.227	(65.741)	(134.432)	(194.650)	(357.770)	

* Includes assets which first entered the regulatory asset register in a disclosure year prior to 2004.



Appendix B Orion Instructions to Engineer



Direct dial: 03 363 9526
Email: Dennis.Jones@oriongroup.co.nz

by email

27 September 2012

Richard Fairbairn
SKM
Auckland

Dear Richard/SKM,

Initial RAB: Engineers Report

- 1 Thank you for your proposal to provide an Independent Engineers Report in relation to the establishment of Orion's Initial Regulatory Asset Base (RAB).
- 2 We require you to review the changes that we have made to our initial RAB and confirm that they meet with the requirements of the asset adjustment process outlined in Clause 2.2.1 of the Commerce Commission's Input Methodology Determination.
- 3 In particular, the adjustments Orion has made that relate to clause 2.2.1(2)(b)(iii) where we have re-categorised post 1 April 2004 additions for the purpose of calculating depreciation. Please note we have not made any other adjustments nor any adjustments to assets existing at 2004.
- 4 SKM's output would be in the form of an Independent Engineers Report that meets with the requirements specified in Schedule E of the "Notice to Supply Information to the Commerce Commission Section 53ZD of the Commerce Act 1986" which was issued to Orion on 27th August 2012.
- 5 In order to assist your review we would make available all the necessary information/resources and key personnel.

Regards,

Dennis Jones
Industry Developments Manager

Since 1994, proud supporter of  community energy action
charitable trust

ORION NEW ZEALAND LIMITED
200 Armagh Street, PO Box 13896, Armagh, Christchurch 8141, New Zealand
PHONE +64 3 363 9898 | FAX +64 3 363 9899 | oriongroup.co.nz



Appendix C Signed Statement by Engineer



Bruce Rogers
Pricing Manager (Commercial)
Orion New Zealand Limited
PO Box 13896
Christchurch 8141
New Zealand

9 October 2012

ZP01286

Dear Sir

**Statement Regarding Independent Engineer's Report on the
Asset Adjustment Process of Orion New Zealand Limited**

Introduction

Sinclair Knight Merz Ltd (SKM) was requested by Orion NZ Ltd (Orion) to undertake an independent review of proposed adjustments to its regulatory asset base as at 31st March 2004. This review was undertaken to determine the appropriateness of the proposed adjustments in respect of the process set out in clause 2.2.1 of the "Commerce Act (Electricity Distribution Input Methodologies) Determination 2010", 22 December 2010 (EDB IM).

SKM's findings are set out in the enclosed report which has been prepared to comply with the requirements for the Independent Engineer's report in Schedule C of the Commerce Commission's "Notice to supply information to the Commerce Commission Section 53ZD of the Commerce Act 1986 (Section 53ZD Notice) dated 27 August 2012. This letter incorporates the signed statement required by the Section 53ZD Notice.

Confirmation of Independence and Qualifications

I, as a chartered professional engineer (as defined in section 6 of the Chartered Professional Engineers Act 2002), can confirm that:

- 1) SKM has acted independently with respect to Orion and its subsidiaries and affiliates;
- 2) SKM has significant experience in New Zealand, Australia and the United Kingdom in relation to the valuation of electricity networks for both regulatory and financial reporting purposes. SKM's review and the preparation of the report have been undertaken by Dr Richard Fairbairn and Mr Stephen Wightman. Dr Fairbairn and Mr Wightman are professionally qualified and experienced in the type of work concerned and are familiar with the Orion network;
- 3) the report is in writing and accessible in electronic (PDF file-type) format and includes a copy of the written instructions provided to SKM by Orion (included as Appendix B to the enclosed report), including any subsequent variations or modifications;



- 4) the report includes a table summarising the various asset value adjustments corresponding to Schedule A4 of the Information Disclosure Notice Templates (please see Appendix A to the enclosed report);
- 5) the report provides the minimum information for each category of asset adjustment outlined in Table 1 of the Section 53ZD Notice, together with such additional information sufficient to allow a reader:
 - i. to understand the data, information, calculations and assumptions employed in respect of each category of asset adjustment;
 - ii. to understand the extent to which professional judgement was exercised by SKM and the effect of that judgement in deriving the resultant asset values;
 - iii. to verify the arithmetical accuracy of the asset adjustment calculations; and
- 6) the report may be publicly disclosed by Orion pursuant to an information disclosure determination in relation to Orion made by the Commission under section 52P of the Commerce Act (1986).

I can confirm that SKM is satisfied that:

- i. the Orion's rules have been properly applied for assets which had not had an Orion valuation calculated originally, as required by clause 2.2.1 of the EDB IM;
- ii. where values under Generally Accepted Accounting Practice have been relied on, those values have been supplied or reviewed by an appropriately qualified party (e.g. accounting practitioner); and
- iii. the report meets the requirements of Schedule C of the Section 53ZD Notice.

SIGNED on behalf of Sinclair Knight Merz Limited by:

A handwritten signature in black ink, appearing to read 'R. Fairbairn', written in a cursive style.

R. Fairbairn, MIET, MIPENZ, CPEng
Sinclair Knight Merz

A handwritten signature in black ink, appearing to read 'S. Wightman', written in a cursive style.

S. Wightman, MIPENZ
Sinclair Knight Merz



Appendix D Initial Regulatory Asset Base as at 31 March 2009

Regulatory valuation of
system fixed assets pursuant to the

Commerce Act
(Electricity Distribution Services Input Methodologies)
Determination 2010

Initial Regulatory Asset Base as at 31 March 2009

Issued 9 October 2012



Contents

Introduction	3
Overview	4
Valuation register database	5
Adjustments to the 2004 ODV Valuation	8
Mapping of ODV Entries to Standard Categories	9
Value as at 31 March 2004	9
Roll-forward 2005 to 2009	11
Additions	11
Disposals.....	11
Revaluation	13
Depreciation	13
Finance During Construction allowance	13
Roll forward summary	14
Reconciliation with information disclosure requirements	15
Value as at 31 March 2009 – the Initial RAB.....	16
Appendix A: Mapping of ODV values to new categories	18
Appendix B: Mapping of Additions values to new categories	26

INTRODUCTION

- 1 Orion New Zealand Limited (Orion) owns and operates the electricity distribution network 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 regions. We receive electricity from Transpower's national grid at 9 separate locations and we distribute this electricity to more than 192,000 homes and businesses.
- 2 As a natural monopoly service provider, we are subject to government regulation under the Commerce Act 1986 (the Act). Pursuant to the requirements of this Act, the Commerce Commission has set a regulatory framework that includes information disclosure (ID) regulation, default price-quality paths (DPP) and the option for electricity distribution businesses (EDBs) to apply for a customised price-quality path (CPP).
- 3 In accordance with the Act, the Commerce Commission has gazetted input methodologies (IMs) to be used in all forms of regulation applying to EDBs. These are embodied in the Commerce Act (Electricity Distribution Services Input Methodologies) Determination 2010 (the Determination) which, among other things, sets out how the regulatory asset base (RAB) value is to be established. ID, DPPs and CPPs require asset values which are established consistent with the IMs.
- 4 In accordance with the IMs, Orion must establish the value of its initial regulatory asset base, the Initial RAB (as at 31 March 2009). The methods to be applied for the Initial RAB are set out in Subpart 2 of Part 2 of the IMs.
- 5 Orion is currently applying for a CPP. In addition, we will shortly be subject to a new ID Determination, which will require us to disclose our Initial RAB (at 31 March 2009).
- 6 In order to facilitate our CPP application, which must be prepared before the ID information has been submitted, the Commerce Commission has issued a "Notice to Supply Information to the Commerce Commission" under section 53ZD of the Act (dated 27 August 2012), which requires us to provide a range of information including the Initial RAB value and supporting information.
- 7 This valuation report documents Orion's establishment of its Initial RAB as at 31 March 2009 consistent with the Determination.

OVERVIEW

- 8 The Determination effectively sets out a valuation method that starts with our 2004 published Optimised Deprival Valuation and rolls it forward. The Determination provides for:
 - 8.1 a set scope of adjustments to the 2004 ODV valuation,
 - 8.2 new asset values (added between 1 April 2004 and 31 March 2009) rolled in at capital cost,
 - 8.3 an allocation methodology for assets that are used to provide services outside the scope of this regulation,
 - 8.4 depreciation based on the remaining life of assets,
 - 8.5 annual revaluation linked to CPI, and
 - 8.6 a finance during construction (FDC) allowance of 2.45% applied to the 31 March 2009 closing value.
- 9 This valuation report sets out our approach for System Fixed Assets (those assets previously represented in our ODV). Other assets are dealt with separately, including head office land and buildings, works under construction, vehicles, IT, sundry plant and equipment, and truck mounted generators.

VALUATION REGISTER DATABASE

- 10 To support the calculation of the Initial RAB, we have established a Microsoft Access database, called the “Regulatory Valuation Register”. The database is structured around a central table into which value entries are loaded. Each entry is linked to a standard reporting category (in the form of IM schedule A) and the database includes functionality to load sequential roll-forward transactions against each valuation entry.

Valuation entry information

	2004 ODV assets	2004 – 2009 roll forward
Valuation ID	Incremental database ID	
Regulatory value category (Mandatory)	RV number Link to IM categorisation for reporting	
Description (Mandatory)	Free form, description of the group of assets represented)	
Origin (Mandatory)	Mandatory, set to 2004 ODV	Either 2004-2009 additions, 2004-2009 disposals
Designation	Either Included, Modified value	Null
Valuation date (Mandatory, effective date the asset is loaded to the valuation register)	31 March 2004	30 September of relevant year
Starting Value (Mandatory, the initial value of the entry)	the ODV value	Either – the gross capital cost of assets (incl vested assets paid for by a customer), – the disposal ODRC (as a negative amount) (cash capital contributions are not entered)
Starting Remaining Life (the remaining life of the asset on entry to the valuation register)	The remaining life for the group of assets from the ODV model	Either – The TL consistent with the ODV Handbook, or – 3 years for disposals
Notes	Freeform memo field to document explanatory notes where relevant	

Roll forward transaction information

- 11 The annual roll forward calculation is carried out valuation-entry by valuation-entry. Each result is explicitly recorded as a transaction and value entries are rounded to the nearest cent. Calculations are as follows:

	2004 – 2009 roll forward
Transaction ID	Incremental database ID
Parent Valuation ID	Link to the valuation entry to which the transaction relates
Opening value	Set to <ul style="list-style-type: none"> - ODV for valuation entry from ODV, else - nil if valuation entry was not present at end of previous year, else - closing value from previous year's transaction.
Revaluation (CPI adjustment, positive increases a positive value entry, negative reduces a negative value asset)	Nil for additions and disposals during the year, otherwise calculate based on disclosure CPI (see below), against opening value.
Depreciation (negative reduces a positive value entry, positive increases a negative valuation entry toward nil)	Calculated as $\frac{(\text{Opening value} + \text{Revaluation}) \times \min(\max(\text{prev closing RL}-3,0),1)}{\text{prev closing remaining life}}$ (ie no depreciation in first part year, calculated against CPI adjusted opening value)
Closing remaining life	Calculate as If first transaction for valuation entry then set to total life (consistent with ODV), else Prev closing remaining life - $\min(\max(\text{prev closing remaining life} -3,0),1)$
Closing value	Calculated as opening value plus additions/disposals plus CPI adjustment plus depreciation

Valuation register example

- 12 The following screen shot shows an example of an entry in the valuation register – 66kV overhead lines (wood) additions during 2005, with transactions rolled-forward to 2009:

Orion Regulatory Valuation Register
Individual Valuation Entries

Valuation category	Category	66kV Overhead lines (wood pole)	
RV010 <input type="text"/>	Standard total life	45	
<input type="checkbox"/> Show closed categories	Cat notes		

Description	Line additions	Record ID
		1335

Date Added	30/09/2004	Origin	2004-2009 Additions <input type="text"/>
Starting Value	\$92,657.84	Starting Remaining Life	45

Notes
Bulk line additions allocated based on disclosure lengths

Roll forward transactions

Fin Year	Opening Value	Revaluation	Depreciation	Closing Value	Closing RL (years)	Std Calcs	Transaction Status	Transaction notes
2005	\$0.00	\$0.00	\$0.00	\$92,657.84	45	Yes <input type="text"/>	Locked	
2006	\$92,657.84	\$3,111.45	(\$2,128.21)	\$93,641.08	44	Yes <input type="text"/>	Locked	
2007	\$93,641.08	\$2,376.61	(\$2,182.22)	\$93,835.47	43	Yes <input type="text"/>	Locked	
2008	\$93,835.47	\$3,158.50	(\$2,255.67)	\$94,738.30	42	Yes <input type="text"/>	Locked	
2009	\$94,738.30	\$5,145.88	(\$2,322.64)	\$97,561.54	41	Yes <input type="text"/>	Locked	
						No <input type="text"/>	Draft	

ADJUSTMENTS TO THE 2004 ODV VALUATION

- 13 Determination clause 2.2.1 sets out an asset adjustment process where we may elect to apply a number of adjustments.
- 14 Orion invested considerable resource into its 2004 ODV and has not subsequently established any significant shortcomings in the information supporting that valuation.
- 15 We have considered each of the provisions for adjustment provided in the Determination and we have elected not to apply any adjustment.
- 16 In terms of Determination clause 2.2.1(1), we designate all assets as “included”, and in terms of clause 2.2.1(4), the value of all assets is taken as its ODV valuation.
- 17 Orion’s published 2004 ODV valuation report establishes the following values:

Extract from published 2004 ODV valuation report

2.1.1 Valuation Summary as at 31 March 2004

System Fixed Assets	\$
Replacement Cost (RC)	1,079,084,452
less Optimisation	(50,279,788)
<i>gives</i> Optimised Replacement Cost (ORC)	<u>1,028,804,664</u>
Depreciated Replacement Cost (DRC)	607,516,171
less Depreciated Optimisation	(27,292,153)
<i>gives</i> Optimised Depreciated Replacement Cost (ODRC)	<u>580,224,018</u>
less Economic Value Adjustment	0
<i>gives</i> Optimised Deprival Value (ODV)	<u>580,224,018</u>

- 18 With our election to not apply any adjustments, the 31 March 2004 value of assets designated as “Included” remains at \$580,224,018.

MAPPING OF ODV ENTRIES TO STANDARD CATEGORIES

- 19 Determination Schedule A sets out a table which provides a basis for standard reporting categories. We have augmented this table to accommodate our range of assets. Appendix A to this report sets out how we have aligned our ODV assets with the new categories.
- 20 The appendix shows that the total value mapped into the new categories matches the published ODV (see section above) of \$580,224,018.
- 21 Of note, we have created a new category for our overhead lines which are recorded as having a mix of wood and concrete pole construction within each segment. It is not possible to split these between the new separate wood and concrete categories. New additions are assigned to the respective wood or concrete pole categories as appropriate.
- 22 ODV valuation entries are mapped and transferred to the new valuation register with their optimised depreciated replacement cost (and remaining life is also carried over). This mapping merely represents a different grouping of valuation entries to better match the format of IM schedule A. It does not represent a recategorisation to adjust total lives or remaining lives, as no such change has been made. The new categories are not comparable with the categories in the 2004 ODV report - even where the category heading is the same, the definition of the items included in each category is different.

Value as at 31 March 2004

- 23 After loading in the new valuation register, the 31 March 2004 value totals by IM Schedule A category heading are:

Schedule A Section Heading*	Total Starting Value
Subtransmission	\$55,536,066
Zone substations	\$85,507,051
HV Distribution conductors	\$163,972,019
HV Distribution switchgear	\$41,950,406
Distribution Substations	\$82,913,961
LV Distribution	\$145,039,433
Other system fixed assets	\$5,305,082
	\$580,224,018

*augmented as noted above

24 And the values by category are:

Section Heading	Standard Cat Code	Cat Name	Total Starting Value
Subtransmission	RV010	66kV Overhead lines (wood pole)	\$3,010,670
Subtransmission	RV015	66kV Overhead lines (steel tower and steel pole)	\$723,539
Subtransmission	RV020	66kV Underground cables (PILC & Oil filled)	\$23,236,758
Subtransmission	RV025	66kV Underground cables (XLPE)	\$9,521,316
Subtransmission	RV045	33kV Overhead lines (mixed construction)	\$8,181,590
Subtransmission	RV050	33kV Underground cables (PILC & Oil filled)	\$1,046,645
Subtransmission	RV055	33kV Underground cables (XLPE)	\$2,215,233
Subtransmission	RV065	Pilot / Communications Circuits	\$5,676,390
Subtransmission	RV070	Air break isolators & surge diverters (66/33kV)	\$1,923,924
Zone substations	RV100	Zone sub land	\$6,129,423
Zone substations	RV105	Zone sub site development and buildings	\$13,418,124
Zone substations	RV110	Power transformers	\$21,437,535
Zone substations	RV115	Indoor circuit breakers (sealed & unsealed, 66/33/11kV)	\$22,939,410
Zone substations	RV125	Outdoor circuit breakers and switchgear (66/33/11kV)	\$636,188
Zone substations	RV135	Protection (mixed digital & electromechanical)	\$8,995,803
Zone substations	RV140	Outdoor structure (concrete pole)	\$3,816,903
Zone substations	RV150	Zone sub SCADA, communications, metering	\$2,112,159
Zone substations	RV155	Ripple injection	\$4,840,303
Zone substations	RV160	DC Supplies, batteries and inverters	\$139,462
Zone substations	RV165	Other items	\$1,041,741
HV Distribution	RV220	11kV Overhead lines (mixed construction)	\$49,674,008
HV Distribution	RV240	11kV Underground cables (PILC)	\$88,317,987
HV Distribution	RV250	11kV Underground cables (XLPE)	\$25,980,024
HV Distribution	RV300	11kV Disconnectors & dropout fuses, Surge diverters (3ph)	\$13,224,686
HV Distribution	RV320	11kV Circuit breaker/recloser & sectionalisers	\$1,106,100
HV Distribution	RV330	11kV Voltage regulators	\$1,572,789
HV Distribution	RV340	11kV MSU and oil switches	\$23,616,709
HV Distribution	RV350	Distribution SCADA, communications, metering	\$2,291,145
HV Distribution	RV360	Switchgear cabinet	\$138,978
Distribution	RV400	Distribution sub land	\$19,141,050
Distribution	RV410	Distribution transformers (pole)	\$17,510,750
Distribution	RV420	Distribution transformers (pad)	\$35,740,123
Distribution	RV430	Distribution substations mount (pole)	\$3,101,300
Distribution	RV440	Distribution substations mount (pad)	\$6,981,247
Distribution	RV450	Distribution substation mount (building)	\$439,491
LV Distribution	RV520	LV Overhead lines (mixed construction)	\$31,551,573
LV Distribution	RV530	LV Underground cables (PILC)	\$4,697,654
LV Distribution	RV540	LV Underground cables (XLPE)	\$80,623,584
LV Distribution	RV550	LV Customer service connections and link pillars	\$28,166,621
Other system	RV600	SCADA and communications, UHF masters and repeaters	\$1,415,318
Other system	RV610	Network spares	\$3,889,764
			\$580,224,018

ROLL-FORWARD 2005 TO 2009

- 25 The roll-forward from 1 April 2004 to 31 March 2009 takes account of additions, disposals, depreciation, revaluations, and a one-off finance during construction (FDC) allowance using the 2008 Information Disclosure Requirements (2008 IDRs) asset valuation methodology.
- 26 The 2008 IDRs provide for asset register corrections identified in our annual regulatory accounts to be included in the roll forward. We did not identify any lost or found assets in our regulatory reporting, so no amounts are included.

Additions

- 27 During the period, additions were rolled in to our regulatory accounts based on capital cost. Assets that were constructed by others and vested to Orion are included and were valued using the 2004 ODV unit replacement cost indexed with a CPI factor (consistent with our approach in our audited annual regulatory disclosures).
- 28 For regulatory accounting purposes, assets were grouped into approximately 15 general ledger categories, and values were assigned between these categories based on job closure forms.
- 29 The new valuation register sets out a much greater disaggregation of asset categories, with approximately 46 categories. We have therefore taken the opportunity to improve the asset categorisation in the roll forward of additions to correct the inherent errors in the previous grouped approach, consistent with provisions of 2.2.1(2)(b)(iii) of the Determination. To this end, we allocated the regulatory account general ledger categories between the new categories using the methodology and assumptions set out in Appendix B to this report.
- 30 All additions are assumed to have occurred mid-way through the relevant period (30 September), consistent with the approach previously adopted for regulatory reporting purposes.

Disposals

- 31 During the period we captured actual disposals and valued them according to the ODV methodology, resulting in a total disposals amount in each of 4 categories: cables, lines, transformers, and "other". The actual assets removed were not identified in, or linked to, our 2004 valuation register (which is essentially a snapshot of assets as at 31 March 2004).
- 32 As we cannot identify the individual assets removed, we have instead loaded the disposals values previously disclosed as negative additions to offset the total value. We have assigned a 3 year minimum remaining life to these disposals to offset the depreciation of the value entries that would otherwise have been removed (effectively assuming that all removed assets are at or close to the end of their lives).

- 33 Consistent with the provisions of clause 2.2.1(2)(b)(iii) of the Determination we have corrected the asset categorisation of the disposal amounts by splitting them between the new more disaggregated and hence more accurate categories. We have done this in proportion to the 2004 ODV value of assets for each relevant category, as follows:

Cables disposal value

Split between LV and 11kV in proportion to 2004 asset values:

Standard Cat Code	Cat Name	Total Starting Value	Proportion
RV240	11kV Underground cables (PILC)	\$88,317,987	44.2%
RV250	11kV Underground cables (XLPE)	\$25,980,024	13.0%
RV530	LV Underground cables (PILC)	\$4,697,654	2.4%
RV540	LV Underground cables (XLPE)	\$80,623,585	40.4%
			100.0%

Lines disposal value

Split between LV and 11kV mixed construction in proportion to 2004 asset values

Standard Cat Code	Cat Name	Total Starting Value	Proportion
RV220	11kV Overhead lines (mixed construction)	\$49,603,069	61.1%
RV520	LV Overhead lines (mixed construction)	\$31,551,573	38.9%
			100.0%

Transformers disposal value

Split between pole and pad in proportion to 2004 asset values

Standard Cat Code	Cat Name	Total Starting Value	Proportion
RV410	Distribution transformers (pole)	\$17,510,750	32.9%
RV420	Distribution transformers (pad)	\$35,740,123	67.1%
			100.0%

Other disposal value

Split between all other assets (excl land/buildings/spares) in proportion to 2004 ODV value

Standard Cat Code	Cat Name	Total Starting Value	Proportion
RV070	Air break isolators & surge diverters (66/33kV)	\$1,923,924	1.7%
RV115	Indoor circuit breakers (66/33/11kV)	\$12,052,955	10.4%
RV120	Indoor circuit breakers sealed (66/33/11kV)	\$10,886,454	9.4%
RV125	Outdoor circuit breakers and switchgear (66/33/11kV)	\$636,188	0.5%
RV135	Protection (mixed digital & electromechanical)	\$8,995,803	7.8%
RV300	11kV Disconnectors & dropout fuses	\$12,495,793	10.8%
RV310	Surge diverters (3ph, 66/33kV)	\$728,893	0.6%
RV320	11kV Circuit breaker/recloser & sectionalisers	\$1,106,100	1.0%
RV330	11kV Voltage regulators	\$1,572,789	1.4%
RV340	11kV MSU and oil switches	\$23,616,709	20.4%
RV350	Distribution SCADA, communications, metering	\$2,291,145	2.0%
RV430	Distribution substations mount (pole)	\$3,101,300	2.7%
RV440	Distribution substations mount (pad)	\$6,981,247	6.0%
RV550	LV Customer service connections and link pillars	\$28,166,621	24.3%
RV600	SCADA and communications, UHF masters and repeaters	\$1,415,318	1.2%
			100.0%

- 34 As disposals run through the asset register as negative assets, it is important that their category groupings are as consistent with the asset groupings as possible to ensure the disposal profile matches the asset profile.

Revaluation

- 35 The revaluation amount for each year is calculated against the opening value for each valuation entry multiplied by the revaluation rate. It reflects the CPI movement in the value of those assets over the year. Additions during the year in question do not attract a revaluation.
- 36 The revaluation rate is the rate used in our audited regulatory disclosures as set out in Determination clause 2.2.9. It is based on 31 March CPI figures as follows:

Year to 31 March	CPI (All groups index SEA9)	Revaluation rate (rounded to 3 decimal places)
2004	928	
2005	953	2.694%
2006	985	3.358%
2007	1010	2.538%
2008	1044	3.366%
2009	1075	2.969%

Depreciation

- 37 The depreciation for each year is calculated against by adding the revaluation amount (calculated above) to the opening value for each valuation entry and then dividing this by the remaining life. Additions during the year in question do not attract depreciation. A minimum remaining life of 3 years is maintained (ie assets are not depreciated beyond a 3 year remaining life).
- 38 A closing remaining life is also calculated as the opening remaining life minus 1, subject to the 3 year minimum remaining life.

Finance During Construction allowance

- 39 Determination clause 2.2.3(1) and (2) provides for the 2009 value of system fixed assets to be multiplied by 1.0245 to account for the cost of finance during construction which is not provided for in previous values.
- 40 This addition equates to \$18,007,834 as noted in the roll forward summary below. Within the database, the revaluation amount has been added into the revaluation part of the 2009 roll-forward transaction.

Roll forward summary

41 The resulting roll-forward totals are:

Year To 31 March	Total Opening Value	Additions	Disposals	Depreciation	Revaluation	Total closing Value
2005	\$580,224,018	\$34,934,212	(2,064,921)	(19,854,317)	\$15,631,235	\$608,870,227
2006	\$608,870,227	\$31,388,520	(1,198,394)	(21,158,730)	\$20,445,862	\$638,347,486
2007	\$638,347,486	\$29,480,721	(843,000)	(22,236,413)	\$16,201,259	\$660,950,054
2008	\$660,950,054	\$41,252,429	(1,019,529)	(23,278,130)	\$22,247,579	\$700,152,403
2009	\$700,152,403	\$39,418,799	(810,873)	(24,534,221)	\$20,787,525	\$735,013,633
<i>plus</i> Finance during construction (FDC) allowance calculated at 2.45%						\$18,007,834
31 March 2009 RAB						\$753,021,468

Reconciliation with information disclosure requirements

- 42 The following table provides a comparison with the annual regulatory valuation roll-forward report disclosed in report AV1 of our Electricity Distribution (Information Disclosure) Requirements as published for the year ending 31 March 2010:

Financial year ending 31 March		Original disclosure	Revised amount	Difference	Cumulative difference
2005	Opening value	\$580,224,000	\$580,224,018	\$18	
	Additions	\$34,934,000	\$34,934,212	\$212	
	Disposals	(\$2,065,000)	(2,064,921)	\$79	
	Depreciation	(\$19,854,000)	(19,854,317)	(317)	
	Revaluation	\$15,631,000	\$15,631,235	\$235	
	Total closing value	\$608,870,000	\$608,870,227	\$227	\$227
2006	Additions	\$31,388,000	\$31,388,520	\$520	
	Disposals	(\$1,198,000)	(1,198,394)	(394)	
	Depreciation	(\$21,092,000)	(21,158,730)	(66,730)	
	Revaluation	\$20,445,000	\$20,445,862	\$862	
	Total closing value	\$638,413,000	\$638,347,486	(65,741)	(65,514)
2007	Additions	\$29,481,000	\$29,480,721	(279)	
	Disposals	(\$843,000)	(843,000)	\$0	
	Depreciation	(\$22,104,000)	(22,236,413)	(132,413)	
	Revaluation	\$16,203,000	\$16,201,259	(1,741)	
	Total closing value	\$661,150,000	\$660,950,054	(134,432)	(199,946)
2008	Additions	\$41,252,000	\$41,252,429	\$429	
	Disposals	(\$1,020,000)	(1,019,529)	\$471	
	Depreciation	(\$23,092,000)	(23,278,130)	(186,130)	
	Revaluation	\$22,257,000	\$22,247,579	(9,421)	
	Total closing value	\$700,547,000	\$700,152,403	(194,650)	(394,597)
2009	Additions	\$39,419,000	\$39,418,799	(201)	
	Disposals	(\$811,000)	(810,873)	\$127	
	Depreciation	(\$24,191,000)	(24,534,221)	(343,221)	
	Revaluation	\$20,802,000	\$20,787,525	(14,475)	
	Total closing value	\$735,765,000	\$735,013,633	(357,770)	(751,367)
	Finance During Construction allowance	\$18,026,000	\$18,007,834	(18,166)	(769,533)

- 43 The revised roll-forward carries a greater depreciation charge which occurs as a result of the categorisation corrections of additions provided for under clause 2.2.1(2)(b)(iii) of the Determination. Asset additions are now more correctly allocated to separate categories and depreciation is accordingly calculated using a total life for each asset category consistent with that used in the 2004 ODV valuation. In the original disclosure values, asset additions were grouped into approximately 15 categories and weighted-average total lives (derived from the 2004 ODV valuation) were used to calculate depreciation. Of note:

- 43.1 Overhead line additions are now separated and depreciated over the wood-pole 45 year life, whereas they were previously depreciated over 49.9 years based on the weighted average of wood and concrete pole additions in the period prior to 2004.
- 43.2 Underground cable additions are now depreciated over the XLPE 45 year life, whereas they were previously depreciated over 46.7 years based on the weighted average of XLPE and PILC cable additions in the period prior to 2004.
- 43.3 Additions previously grouped as “other” assets and depreciated using the weighted average 38.6 year total life are now allocated into separate categories with specific total lives – the resulting average total life is 35.2 years.
- 44 The smaller revaluation differences result from the cumulative effect of the depreciation differences, and all other differences reflect rounding in the original disclosure.

Value as at 31 March 2009 – the Initial RAB

- 45 Following the 2005 to 2009 roll-forward described above, our valuation totals by category heading are:

Schedule A Section Heading	Total Closing Value
Subtransmission	\$58,749,224
Zone substations	\$116,066,465
HV Distribution conductors	\$198,847,737
HV Distribution switchgear	\$55,482,723
Distribution Substations	\$101,111,147
LV Distribution	\$212,351,547
Other system fixed assets	\$10,412,625
	\$753,021,468

46 The valuation totals by category are:

Section Heading	Standard Cat Code	Cat Name	Total Closing Value
Subtransmission	RV010	66kV Overhead lines (wood pole)	\$3,746,828
Subtransmission	RV015	66kV Overhead lines (steel tower and steel pole)	\$462,256
Subtransmission	RV020	66kV Underground cables (PILC & Oil filled)	\$24,166,552
Subtransmission	RV025	66kV Underground cables (XLPE)	\$10,045,266
Subtransmission	RV040	33kV Overhead lines (wood pole)	\$1,445,585
Subtransmission	RV045	33kV Overhead lines (mixed construction)	\$8,009,803
Subtransmission	RV050	33kV Underground cables (PILC & Oil filled)	\$1,094,524
Subtransmission	RV055	33kV Underground cables (XLPE)	\$2,746,420
Subtransmission	RV065	Pilot / Communications Circuits	\$5,125,825
Subtransmission	RV070	Air break isolators & surge diverters (66/33kV)	\$1,906,165
Zone substations	RV100	Zone sub land	\$8,110,071
Zone substations	RV105	Zone sub site development and buildings	\$19,222,599
Zone substations	RV110	Power transformers	\$26,223,902
Zone substations	RV115	Indoor circuit breakers (sealed & unsealed, 66/33/11kV)	\$31,183,427
Zone substations	RV125	Outdoor circuit breakers and switchgear (66/33/11kV)	\$648,245
Zone substations	RV130	Protection (digital)	\$4,735,182
Zone substations	RV135	Protection (mixed digital & electromechanical)	\$8,230,780
Zone substations	RV140	Outdoor structure (concrete pole)	\$3,859,164
Zone substations	RV150	Zone sub SCADA, communications, metering	\$6,548,929
Zone substations	RV155	Ripple injection	\$6,155,497
Zone substations	RV160	DC Supplies, batteries and inverters	\$123,831
Zone substations	RV165	Other items	\$1,024,838
HV Distribution conductors	RV210	11kV Overhead lines (wood pole)	\$15,116,542
HV Distribution conductors	RV220	11kV Overhead lines (mixed construction)	\$47,997,251
HV Distribution conductors	RV240	11kV Underground cables (PILC)	\$92,076,466
HV Distribution conductors	RV250	11kV Underground cables (XLPE)	\$43,657,478
HV Distribution switchgear	RV300	11kV Disconnectors & dropout fuses, Surge diverters (3p	\$19,510,769
HV Distribution switchgear	RV320	11kV Circuit breaker/recloser & sectionalisers	\$1,828,345
HV Distribution switchgear	RV330	11kV Voltage regulators	\$1,571,147
HV Distribution switchgear	RV340	11kV MSU and oil switches	\$30,092,012
HV Distribution switchgear	RV350	Distribution SCADA, communications, metering	\$2,274,016
HV Distribution switchgear	RV360	Switchgear cabinet	\$206,434
Distribution Substations	RV400	Distribution sub land	\$24,599,444
Distribution Substations	RV405	Easements	\$377,798
Distribution Substations	RV410	Distribution transformers (pole)	\$21,933,219
Distribution Substations	RV420	Distribution transformers (pad)	\$42,154,528
Distribution Substations	RV430	Distribution substations mount (pole)	\$2,852,025
Distribution Substations	RV440	Distribution substations mount (pad)	\$8,173,389
Distribution Substations	RV450	Distribution substation mount (building)	\$1,020,744
LV Distribution	RV510	LV Overhead lines (wood pole)	\$14,196,811
LV Distribution	RV520	LV Overhead lines (mixed construction)	\$29,025,714
LV Distribution	RV530	LV Underground cables (PILC)	\$4,763,889
LV Distribution	RV540	LV Underground cables (XLPE)	\$132,982,812
LV Distribution	RV550	LV Customer service connections and link pillars	\$31,382,321
Other system fixed assets	RV600	SCADA and communications, UHF masters and repeaters	\$827,157
Other system fixed assets	RV610	Network spares	\$4,616,293
Other system fixed assets	RV615	Finance leases	\$4,969,175
			\$753,021,468

APPENDIX A: MAPPING OF ODV VALUES TO NEW CATEGORIES

Regulatory asset value categories in the form of the Commerce Commission's Input Methodologies Determination 2010 with additional entries to cater for ODV assets.

ODV Assets included

Asset Code	Asset Name	IM Standard Life ¹	ODV Standard Life	MEA Code	Orion asset name	Mapped ODV amount
Subtransmission						
RV005	66kV Overhead lines (concrete pole)	60	60		No concrete in ODV, but some since	
RV010	66kV Overhead lines (wood pole)	45	45	MEA0030	66kV OH Medium (single circuit wooden pole)	3,010,670
RV015	66kV Overhead lines (steel tower and steel pole)	55	55	MEA0020	66kV OH Heavy (Dcst wolf)	625,757
				MEA0025	66kV OH Heavy (Dcst hyena)	97,782
RV020	66kV Underground cables (PILC)	70	70	MEA0010	66kV UG Heavy Dcct	23,166,254
RV025	66kV Underground cables (XLPE)	55	45	MEA0005	66kV UG Extra heavy	9,521,316
RV030	66kV Underground cables (Oil filled)	NA	70	MEA0015	66kV UG Heavy	70,505
RV035	33kV Overhead lines (concrete pole)	60	60			
RV040	33kV Overhead lines (wood pole)	45	45			
RV045	33kV Overhead lines (mixed construction)	NA	51.6	MEA0035	33kV OH Heavy	269,716
				MEA0040	33kV OH Light	7,911,874
RV050	33kV Underground cables (PILC & Oil)	70	70	MEA0055	33kV UG Heavy	1,006,615
				MEA0060	33kV UG Medium	40,030
RV055	33kV Underground cables (XLPE)	55	45	MEA0055	33kV UG Heavy	2,215,233
RV065	Pilot / Communications Circuits	45	45	MEA0155	Comms UG	5,676,390
RV070	Air break isolators & surge diverters (66/33kV)	35	35	MEA0070	33kV Isolation	79,843
				MEA0075	33kV Surge arresters (3ph)	49,371
				MEA0275	66kV AB isolator	251,702
				MEA0280	66kV AB isolator with E/Sw	176,586
				MEA0300	33kV A B Isolator	196,501

Asset Code	Asset Name	IM Standard Life ¹	ODV Standard Life	MEA Code	Orion asset name	Mapped ODV amount
Zone substations						
RV100	Zone sub land	-	-	MEA0165	Zone substation land	6,129,423
RV105	Zone sub site development and buildings	70	50	MEA0170	Network sub-Orion owned	4,808,229
				MEA0175	Network sub-On customer's premises	291,360
				MEA0180	District sub-11kV urban	1,285,760
				MEA0185	District sub-66or33kV wth outdoor struct	3,697,411
				MEA0190	District sub-sml 66or33kV wth outdoor struct	332,041
				MEA0195	District sub-66kV or 33kV indoor	1,401,400
				MEA0200	District sub-block building	705,250
				MEA0205	District sub-individually assessed structure	896,673
RV110	Power transformers	45	60	MEA0210	66/11kV 20/40MVA	11,468,789
				MEA0215	66/11kV 11.5/23 MVA	313,486
				MEA0220	66/11kV 7.5/10MVA	1,209,398
				MEA0225	33/11kV 11.5/23MVA	1,449,769
				MEA0230	33/11kV 10/20MVA	1,987,783
				MEA0235	33/11kV 7.5/10MVA	484,121
				MEA0240	33/11kV 7.5MVA	3,295,755
				MEA0245	33/11kV 2.5MVA	897,297
				MEA0250	33/11kV 1.5MVA	36,273
				MEA0255	33/11kV 0.75MVA	294,866
RV115	Indoor circuit breakers (sealed & unsealed 66/33/11kV)	45	45	MEA0305	11kV Circuit breaker	11,445,667
				MEA0630	11kV Circuit Breaker (Distn Substation)	498,667
				MEA0270	66kV circuit breaker	1,169,922
				MEA0640	11kV Single phase breaker	108,622
				MEA0310	11kV circuit breaker sealed	10,543,636
				MEA0635	11kV Circuit Breaker Sealed (Distn Sub)	342,818
RV125	Outdoor circuit breakers and switchgear (66/33/11kV)	40	40	MEA0295	33kV circuit breaker (outdoor)	636,188
RV130	Protection (digital)	20	20			
RV135	Protection (mixed digital & electromechanical)	NA	40	MEA0340	66kV Unit protection (with intertrip)	814,334
				MEA1250	Directional overcurrent relay (with CB fail)	149,050
				MEA0350	Transformer diff protection & control (+intertrip)	477,354
				MEA0345	Transformer diff protection & control	1,621,889
				MEA0355	11/33kV Feeder protection (with OC & EF)	115,545

Asset Code	Asset Name	IM Standard Life ¹	ODV Standard Life	MEA Code	Orion asset name	Mapped ODV amount
				MEA0365	11/33kV Unit protection (with OC)	1,375,350
				MEA0360	11/33kV Unit protection	1,594,098
				MEA0370	11kV Protection (with OC & EF)	1,790,036
				MEA1255	11kV Protection (with OC, EF, reclose & CB fail)	567,991
				MEA0375	Bus bar protection relay	490,157
RV140	Outdoor structure (concrete pole)	60	60	MEA0380	Structure 66kV - incomer	374,524
				MEA0385	Structure 66kV - bus section	475,737
				MEA0390	Structure 66kV - isolator section	146,624
				MEA0395	Structure 66kV - feeder	533,305
				MEA0400	Structure 33kV - incomer	256,921
				MEA0405	Structure 33kV - bus section	829,134
				MEA0410	Structure 33kV -isolator section	120,257
				MEA0415	Structure 33kV - feeder	1,080,401
RV145	Outdoor structure (wood pole)	45	45			
RV150	Zone sub SCADA, communications, metering	15	15 (40 for metering)	MEA0160	GXP check metering	204,069
				MEA0420	RTU (large urban district sub)	225,923
				MEA1155	RTU (medium urban district sub)	385,633
				MEA1160	RTU (small urban district sub)	248,721
				MEA1165	RTU (small rural district sub)	466,513
				MEA1170	RTU (medium network sub)	35,001
				MEA1175	RTU (small network sub)	457,700
				MEA0425	Pilot box 140 way	8,405
				MEA0430	Pilot box 280 way	80,196
RV155	Ripple injection	20	20	MEA0435	Ripple injection plant (11kV, 175Hz)	4,090,776
				MEA1125	Ripple injection plant (11kV, 317Hz)	433,228
				MEA0440	Ripple injection plant (33kV, 317 Hz)	275,800
				MEA0445	Ripple wave trap (66kV 175Hz)	40,500
RV160	DC Supplies, batteries and inverters	20	20	MEA0450	Battery (50/100AH), charger (110V) & stand	118,892
				MEA0455	Battery (50/100AH), charger (50V) & stand	20,570
RV165	Other items	40	40	MEA0460	11kV AT (15kVA)	49,098
				MEA0465	11kV Incomer Cable 40MVA	409,568
				MEA0470	11kV Incomer Cable 20MVA	44,291
				MEA0475	11kV Incomer Cable 10MVA	103,239
				MEA0480	11kV Bus coupler cable 20MVA	78,246
				MEA0485	11kV Bus coupler cable 10MVA	7,252
				MEA0490	66kV VT (3ph)	35,803

Asset Code	Asset Name	IM Standard Life ¹	ODV Standard Life	MEA Code	Orion asset name	Mapped ODV amount
				MEA0495	66kV Surge diverter (3ph)	30,742
				MEA0500	33kV VT (3ph)	7,668
				MEA0505	33kV Surge diverter (3ph)	7,508
				MEA0510	11kV VT (3ph)	184,772
				MEA0515	11kV Neutral earthing resistor	83,554
HV Distribution conductors						
RV200	11kV Overhead lines (concrete pole)	60	60			
RV210	11kV Overhead lines (wood pole)	45	45			
RV220	11kV Overhead lines (mixed construction)	NA	52.2 (49.4 for traffic mgmt)	MEA0520	11kV OH Heavy	287,403
				MEA0525	11kV OH Medium	15,023,327
				MEA0530	11kV OH Light	21,667,928
				MEA1270	11kV OH Two phase	8,736,624
				MEA0535	11kV OH SWER	1,895,052
				MEA0540	11kV OH Heavy underbuilt	423
				MEA0545	11kV OH Medium underbuilt	1,608,277
				MEA0550	11kV OH Light underbuilt	344,554
				MEA1280	11kV OH Two phase underbuilt	39,483
				MEA1130	Traffic mgmt (OH Level 1)	46,346
				MEA1135	Traffic mgmt (OH Level 2)	24,593
RV240	11kV Underground cables (PILC)	70	70	MEA0555	11kV UG Extra heavy	462,138
				MEA0560	11kV UG Heavy	2,599,491
				MEA0565	11kV UG Medium	18,458,140
				MEA0570	11kV UG Light	13,186,187
				MEA0575	11kV UG Extra heavy Dcct	7,201,907
				MEA0580	11kV UG Heavy Dcct	14,371,604
				MEA0585	11kV UG Medium Dcct	19,454,442
				MEA0590	11kV UG Light Dcct	10,751,469
				MEA1140	Traffic mgmt (UG level 1)	488,917
				MEA1145	Traffic mgmt (UG level 2)	981,458
				MEA1150	Traffic mgmt (UG level 2-in road)	362,234
RV250	11kV Underground cables (XLPE)	55	45	MEA0555	11kV UG Extra heavy	26,919
				MEA0560	11kV UG Heavy	315,101
				MEA0565	11kV UG Medium	5,425,839
				MEA0570	11kV UG Light	4,483,781
				MEA0575	11kV UG Extra heavy Dcct	12,476
				MEA0580	11kV UG Heavy Dcct	2,906,060
				MEA0585	11kV UG Medium Dcct	5,289,292
				MEA0590	11kV UG Light Dcct	3,504,752
				MEA1140	Traffic mgmt (UG level 1)	1,071,367

Asset Code	Asset Name	IM Standard Life ¹	ODV Standard Life	MEA Code	Orion asset name	Mapped ODV amount
				MEA1145	Traffic mgmt (UG level 2)	2,150,674
				MEA1150	Traffic mgmt (UG level 2-in road)	793,764
HV Distribution switchgear						
RV300	11kV Disconnectors & dropout fuses, Surge diverters (3ph)	35	35	MEA0595	11kV Disconnecter (3ph)	1,076,100
				MEA0610	11kV Dropout fuse (3ph set)	9,179,464
				MEA1265	11kV Dropout fuse (1ph)	78,029
				MEA0615	11kV Dropout fuse (2ph set)	2,162,200
				MEA0645	11kV Surge arresters (3ph)	728,893
RV320	11kV Circuit breaker/recloser & sectionalisers	40	40	MEA0625	11kV Circuit breaker / recloser (pole-mounted)	1,041,525
				MEA0620	11kV Sectionaliser	64,575
RV330	11kV Voltage regulators	55	55	MEA0260	11kV Regulator (20MVA)	136,827
				MEA0265	11kV Regulator (4MVA)	1,435,962
RV340	11kV MSU and oil switches	40	40	MEA0655	11kV Magnefix type UT	482,213
				MEA0660	11kV Magnefix type 1K2T	333,771
				MEA0665	11kV Magnefix type 1K3T	18,842
				MEA0670	11kV Magnefix type 2K1T	3,932,239
				MEA0675	11kV Magnefix type 2K2T	421,595
				MEA0680	11kV Magnefix type 2K3T	14,615
				MEA0685	11kV Magnefix type 2KB2K	3,629,217
				MEA0690	11kV Magnefix type 2KBK	3,262,210
				MEA0695	11kV Magnefix type 3K	3,629,319
				MEA0700	11kV Magnefix type 3K1T	2,552,982
				MEA0705	11kV Magnefix type 3K2T	39,347
				MEA0710	11kV Magnefix type 3KX	4,999
				MEA0715	11kV Magnefix type 4K	5,170
				MEA0720	11kV Magnefix type 4K1T	166,760
				MEA0725	11kV Magnefix type 5K	118,061
				MEA0730	11kV Magnefix type KB2K	233,853
				MEA0735	11kV Magnefix type KB2KBK	1,523,511
				MEA0740	11kV Magnefix type KBX	2,734,321
				MEA0745	11kV Magnefix type KTB	317,836
				MEA0755	11kV Oil switch (not fused)	63,450
				MEA0760	11kV Oil switch (fused)	132,400
RV350	Distribution SCADA, communications, metering	15	15 (40 for metering)	MEA0765	UHF remote Unit	179,722
				MEA1180	RTU Aux equip (pole mount on LCB)	252,461
				MEA0930	Distn Sub - LV MDI metering (800A)	1,578,638
				MEA0935	Distn Sub - LV MDI metering (1500A)	280,324

Asset Code	Asset Name	IM Standard Life ¹	ODV Standard Life	MEA Code	Orion asset name	Mapped ODV amount
RV360	Switchgear cabinet	45	45	MEA0750	11kV Switchgear cabinet (1/4 Kiosk)	138,978
Distribution Substations						
RV400	Distribution sub land	-	-	MEA0885	Distn Sub - Land	19,141,050
RV410	Distribution transformers (pole)	45	45	MEA0770	1ph Pole mount ≤ 15 kVA	1,747,430
				MEA0775	1ph Pole mount 30 kVA	113,777
				MEA0790	1ph Pole mount 100 kVA	2,878
				MEA0815	3ph Pole mount ≤ 30 kVA	6,431,720
				MEA0820	3ph Pole mount 50 kVA	3,943,411
				MEA0825	3ph Pole mount 100 kVA	3,692,200
				MEA0830	3ph Pole mount 200 kVA	1,543,245
				MEA0835	3ph Pole mount 300 kVA	36,089
RV420	Distribution transformers (pad)	45	55	MEA0795	1ph Pad mount ≤ 15 kVA	20,445
				MEA0800	1ph Pad mount 30 kVA	12,660
				MEA0805	1ph Pad mount 50 kVA	0
				MEA0810	1ph Pad mount 75 kVA	0
				MEA0845	3ph Pad mount 100 kVA	408,764
				MEA0850	3ph Pad mount 200 kVA	8,841,763
				MEA0855	3ph Pad mount 300 kVA	12,282,327
				MEA0860	3ph Pad mount 500 kVA	8,669,800
				MEA0865	3ph Pad mount 750 kVA	3,424,672
				MEA0870	3ph Pad mount 1000 kVA	1,957,236
				MEA0875	3ph Pad mount 1250 kVA	36,727
				MEA0880	3ph Pad mount 1500 kVA	85,727
RV430	Distribution substations mount (pole)	45	45	MEA0890	Distn Sub - Pole mount (≤50 kVA)	2,184,834
				MEA0895	Distn Sub - Pole mount (>50 kVA, <100 kVA)	112,800
				MEA0900	Distn Sub - Pole mount (≥100 kVA)	803,666
RV440	Distribution substations mount (pad)	45	55	MEA0905	Distn Sub - Pad mount (Orion full kiosk)	5,621,491
				MEA0910	Distn Sub - Pad mount (Orion 1/2 kiosk)	1,359,756
RV450	Distribution substation mount (building)	45	55	MEA0920	Distn Sub - Building (Orion owned)	220,400
				MEA0925	Distn Sub - Building (customer owned)	219,091
LV Distribution						
RV500	LV Overhead lines (concrete pole)	60	60			
RV510	LV Overhead lines (wood pole)	45	45			
RV520	LV Overhead lines (mixed construction)	NA	49.35	MEA0940	LV OH Heavy 4 wire	699,913
				MEA0945	LV OH Medium 4 wire	15,620,013

Asset Code	Asset Name	IM Standard Life ¹	ODV Standard Life	MEA Code	Orion asset name	Mapped ODV amount
				MEA0950	LV OH Light 4 wire	422,985
				MEA0955	LV OH Medium 2 wire	540,019
				MEA0960	LV OH Light 2 wire	19,678
				MEA0965	LV OH Heavy 4 wire underbuilt	14,327
				MEA0970	LV OH Medium 4 wire underbuilt	2,110,652
				MEA1105	LV OH Light 4 wire underbuilt	149,316
				MEA0975	LV OH Medium 2 wire underbuilt	432,688
				MEA0980	LV OH Light 2 wire underbuilt	7,226
				MEA0985	LV OH Urban Road Crossings & Back Sections	4,319,784
				MEA0990	LV OH Rural Road Crossings & Back Sections	5,500,437
				MEA0995	LV OH Lighting (on own)	1,372,207
				MEA1115	LV OH Lighting (with LV)	0
				MEA1120	LV OH Lighting (with HV)	342,330
RV530	LV Underground cables (PILC)	70	70	MEA1000	LV UG Heavy	6,821,900
				MEA1005	LV UG Medium	49,955,092
				MEA1010	LV UG Service Main (16mm ² NS)	5,978,991
				MEA1015	LV UG Heavy shared trench	1,269,118
				MEA1020	LV UG Medium shared trench	9,948,165
				MEA1025	LV UG Lighting 2 core (on own)	6,650,318
				MEA1110	LV UG Lighting 2 core (with LV)	0
				MEA1035	LV UG Lighting 5th core (with LV)	0
RV540	LV Underground cables (XLPE)	55	45	MEA1000	LV UG Heavy	1,545,520
				MEA1005	LV UG Medium	2,071,334
				MEA1010	LV UG Service Main (16mm ² NS)	213,999
				MEA1015	LV UG Heavy shared trench	381,348
				MEA1020	LV UG Medium shared trench	441,588
				MEA1025	LV UG Lighting 2 core (on own)	43,865
				MEA1110	LV UG Lighting 2 core (with LV)	0
				MEA1035	LV UG Lighting 5th core (with LV)	0
RV550	LV Customer service connections and link pillars	45	45	MEA1040	LV 2 way linkbox / multibox	3,507,133
				MEA1045	LV 3 way linkbox / multibox	2,077,067
				MEA1050	LV 4 way linkbox / multibox	1,968,311
				MEA1055	LV connection OH 1ph	1,966,058
				MEA1060	LV connection OH 3ph	577,652
				MEA1065	LV connection UG 1ph (fuse only)	890,172
				MEA1100	LV connection UG 3ph (fuse only)	142,218
				MEA1070	LV connection UG 1ph (shared bndry box)	9,668,958
				MEA1075	LV connection UG 1ph (dedicated bndry box)	1,417,661
				MEA1080	LV connection UG 3ph (shared bndry box)	4,969,329

Asset Code	Asset Name	IM Standard Life ¹	ODV Standard Life	MEA Code	Orion asset name	Mapped ODV amount
				MEA1085	LV connection UG 3ph (dedicated bndry box)	982,062
Other system fixed assets						
RV600	SCADA and communications, UHF masters and repeaters	15	15	MEA1090	SCADA master station	1,290,218
				MEA1095	UHF masters	61,600
				MEA1245	UHF repeaters	63,500
RV610	Network spares	NA	NA	MEA1195	66kV UG Spares	806,965
				MEA1185	66kV OH Spares	22,696
				MEA1200	33kV OH spares	8,629
				MEA1205	33kV UG Spares	85,780
				MEA1240	11kV circuit breaker spares	1,039,662
				MEA1215	Subtransmission spares	1,071,376
				MEA1225	11kV OH Spares	9,074
				MEA1235	Distribution transformer spares	263,622
				MEA1220	Distribution spares	70,087
				MEA1260	Distribution switchgear spares	93,048
				MEA1230	11kV UG Spares	2,801
				MEA1210	Ripple spares	416,024
						580,224,018

APPENDIX B: MAPPING OF ADDITIONS VALUES TO NEW CATEGORIES

Original general ledger addition categories	... Allocated to ...	New Regulatory Valuation Register Categories	Allocation method	Resulting proportion	
B312013	Ripple Injection	RV155	Ripple injection	Full allocation	
B312023	Transformer charges	RV110	Power transformers	Individual identification of capital expenditure that relates to zone substations	
		RV410	Distribution transformers (pole)	Balance of GL category allocated in proportion to new assets in 5 years to	42.0%
		RV420	Distribution transformers (pad)		58.0%
B312033	Underground cables	RV025	66kV Underground cables (XLPE)	Capital expenditure on underground cables predominantly relates to the installation of new XLPE cables. Old cables are not usually removed nor maintained. Consistent with this, the capital expenditure has been allocated to XLPE categories across the different voltages based on the change in disclosed lengths for each year. Resulting	0.0% to 0.6%
		RV055	33kV Underground cables (XLPE)		0.0% to 3.0%
		RV250	11kV Underground cables (XLPE)		15.8% to 64.3%
		RV540	LV Underground cables (XLPE)		33.7% to 84.2%
B312043	Overhead Lines	RV005	66kV Overhead lines (concrete pole)	Actual concrete pole projects identified and allocated	
		RV010	66kV Overhead lines (wood pole)	Temporary urban 66kV overhead identified and allocated	
		RV010	66kV Overhead lines (wood pole)	Capital expenditure on overhead lines relates to new wood pole lines in the rural area and maintenance and condition based replacement with wood poles across the network. Consistent with this, the balance of capital expenditure has been allocated to wood pole categories across the different voltages based on the total disclosed lengths for each year. Resulting	1.6% to 2.2%
		RV040	33kV Overhead lines (wood pole)		4.4% to 4.7%
		RV210	11kV Overhead lines (wood pole)		47.9% to 48.4%
		RV510	LV Overhead lines (wood pole)		45.0% to 45.6%
B312053	SCADA Equip.	RV150	Zone sub SCADA, communications, metering	Full allocation	
B312083	LV S/Gear & Misc equip	RV350	Distribution SCADA, communications, metering	Capital expenditure allocated in proportion to value of new assets added in 5 years to 31/3/2004	6.2%
		RV550	LV Customer service connections and link pillars		93.8%
B312093	HV S/Gear & Misc equip	RV070	Air break isolators & surge diverters (66/33kV)	Capital expenditure allocated in proportion to value of new assets added in 5 years to 31/3/2004	3.9%
		RV115	Indoor circuit breakers (sealed & switchgear (66/33/11kV)		28.5%
		RV125	Outdoor circuit breakers and switchgear (66/33/11kV)		0.3%
		RV130	Protection (digital)		15.5%
		RV165	Other items		0.4%
		RV300	11kV Disconnectors & dropout fuses, Surge diverters (3ph)		22.2%
		RV320	11kV Circuit breaker/recloser & sectionalisers		2.3%
		RV340	11kV MSU and oil switches		26.7%
		RV360	Switchgear cabinet		0.2%
B312103	SCADA & Ripple Soft	RV600	SCADA and communications, UHF masters and repeaters	Full allocation	
B444003	Buildings District	RV105	Zone sub site development and	Full allocation	
B444013	Buildings Network Subs				
B444023	Buildings Kiosk/	RV440	Distribution substations mount		
B444023	Buildings C/Owned	RV450	Distribution substation mount	Full allocation	
B444063	Buildings Dist Subs				
B444073	Buildings Dist Subs				
B444033	Buildings Pole	RV430	Distribution substations mount	Full allocation	
B474003	Land Subs & Kiosk Land	RV100	Zone sub land	Individual identification of capital expenditure that relates to zone substations, balance of GL code allocated	
		RV400	Distribution sub land		
B474013	Land Easements	RV405	Easements	Full allocation	
B474023	Kiosks				
B474023	Land Easements				

Appendix 15

Depreciation by asset type

Depreciation by asset type (standard depreciation)

IM 5.4.12 (2)(a)

Standard depreciation (\$000)	Current Period			Assessment Period		CPP Period				
	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Sub-transmission network										
66 kV Overhead lines (concrete pole)	-	-	-	5	5	5	5	5	5	5
66 kV Overhead lines (wood pole)	98	103	118	154	222	226	231	236	242	247
66 kV Overhead lines (towers)	100	103	108	13	68	97	235	197	193	196
66 kV Underground cables (PILC)	682	696	714	725	739	752	770	788	806	824
66 kV Underground cables (XLPE)	272	278	285	290	414	422	432	441	451	461
33 kV Overhead lines (wood pole)	34	40	47	52	63	65	66	68	69	71
33 kV Overhead lines (mixed construction)	362	370	381	363	359	351	360	368	377	387
33 kV Underground cables (PILC)	30	30	31	31	32	33	33	34	35	36
33 kV Underground cables (XLPE)	79	86	92	96	109	111	113	116	119	121
Pilot / Communications Circuits	414	424	439	289	287	255	378	424	545	508
Substations										
Zone sub land	-	-	-	-	-	-	-	-	-	-
Zone sub site development and buildings	988	1,044	1,094	924	968	924	1,083	1,150	1,155	1,167
Power Transformers	854	903	926	932	989	1,028	1,207	1,299	1,322	1,337
Protection (electromechanical)	543	556	574	430	414	372	381	391	400	411
Protection (digital)	262	315	393	494	739	775	838	879	897	913
Outdoor Structure (concrete pole)	134	137	140	143	158	167	207	233	237	237
DC Supplies, batteries and inverters	22	23	24	8	18	21	40	51	51	50
Other items	90	93	97	59	59	51	52	53	55	56
Distribution network										
11 kV Overhead lines (wood pole)	351	422	493	552	682	694	711	727	743	759
11 kV Overhead lines (mixed construction)	1,491	1,519	1,548	2,023	2,051	2,048	2,099	2,148	2,199	2,253
11 kV Underground cables (PILC)	2,491	2,543	2,605	2,733	2,783	2,815	2,884	2,949	3,017	3,087
11 kV Underground cables (XLPE)	1,170	1,253	1,426	1,655	1,817	1,840	1,884	1,926	1,969	2,014
Distribution sub land	-	-	-	-	-	-	-	-	-	-
Distribution transformers (pole, 1ph/2ph/3ph)	788	824	861	986	1,030	988	1,012	1,036	1,061	1,087
Distribution transformers (pad)	1,137	1,185	1,231	1,676	1,772	1,717	1,760	1,801	1,844	1,889
Distribution substations mount (pole)	168	174	180	158	154	134	137	141	144	148
Distribution substations mount (pad)	253	265	279	318	364	361	370	378	387	396
Distribution substation mount (building & in customer building)	36	37	39	36	44	41	42	43	44	45
Switchgear cabinet	6	7	7	8	8	8	8	8	9	9
Switchgear										
Surge Diverters (3ph, 66/33kV) / Air break isolators (66/33kV)	88	97	110	106	103	99	102	104	107	109
Indoor circuit breakers and switchgear (66/33/11kV)	1,559	1,635	1,743	1,516	1,651	1,441	1,513	1,583	1,619	1,656
Outdoor circuit breakers and switchgear (66/33/11kV)	59	61	63	44	86	87	143	208	211	210
11kV Disconnectors & Dropout fuses	940	1,000	1,087	1,031	1,075	1,058	1,084	1,109	1,135	1,163
11kV voltage regulators	53	54	55	55	57	51	52	53	54	56
11kV Circuit breaker/recloser & sectionalisers	57	62	69	82	83	85	87	89	91	93
11kV MSU and oil switches	1,523	1,599	1,706	1,618	1,610	1,490	1,527	1,563	1,601	1,643

Standard depreciation (\$000)	Current Period			Assessment Period		CPP Period				
	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Low voltage distribution network										
LV Overhead lines (wood pole)	330	396	462	518	582	593	607	620	634	648
LV Overhead lines (mixed construction)	1,265	1,291	1,322	1,530	1,506	1,337	1,372	1,405	1,440	1,479
LV Underground cables (PILC)	152	155	159	163	167	168	172	176	180	185
LV Underground cables (XLPE)	4,606	4,795	4,993	5,136	5,318	5,200	5,327	5,450	5,577	5,710
Link Pillars & LV customer service connections	1,323	1,408	1,475	1,519	1,616	1,545	1,583	1,620	1,658	1,699
Supporting or secondary systems										
Ripple Injection Plant	489	501	516	439	497	507	519	532	545	559
SCADA and communications	1,129	1,283	1,379	963	1,121	1,047	1,113	1,153	1,219	1,236
Peak load generator	-	-	-	38	39	40	41	42	43	44
Metering systems	-	-	-	-	5	5	6	6	6	6
Easements	-	-	-	-	-	-	-	-	-	-
Network Spares	-	-	-	-	-	-	-	-	-	-
Finance leases	177	191	196	214	218	213	219	224	229	235
Capital Contributions	-	(60)	(111)	(186)	(228)	(231)	(236)	(241)	(245)	(250)
Power factor correction plant	-	-	-	-	-	-	-	-	-	-
EDB-owned mobile substations and generators	-	-	-	-	206	210	215	220	225	230
Non system fixed assets										
Office Buildings	95	106	101	103	105	31	32	33	33	34
Information and Technology Systems	1,453	1,992	2,034	2,456	2,655	945	970	997	1,029	1,073
Office Furniture and Equipment	62	64	71	75	117	85	87	90	92	96
Tools, Plant and Machinery	257	170	208	295	307	227	232	238	245	254
Vehicles	543	588	579	613	643	384	394	404	418	435
Total	29,014	30,817	32,348	33,480	35,886	32,914	34,499	35,568	36,524	37,314

Alternative depreciation (\$000)	Current Period			Assessment Period		CPP Period				
	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19
Low voltage distribution network										
LV Overhead lines (wood pole)	-	-	-	-	-	2	3	6	8	11
LV Overhead lines (mixed construction)	-	-	-	-	-	-	-	-	-	-
LV Underground cables (PILC)	-	-	-	-	-	-	-	-	-	-
LV Underground cables (XLPE)	-	-	-	-	-	9	20	31	43	55
Link Pillars & LV customer service connections	-	-	-	-	-	11	18	29	40	49
Supporting or secondary systems										
Ripple Injection Plant	-	-	-	-	-	7	12	27	39	57
SCADA and communications	-	-	-	-	-	34	73	114	159	214
Peak load generator	-	-	-	-	-	-	-	-	-	-
Metering systems	-	-	-	-	-	1	2	3	4	5
Easements	-	-	-	-	-	-	-	-	-	-
Network Spares	-	-	-	-	-	-	-	-	-	-
Finance leases	-	-	-	-	-	-	-	-	-	-
Capital Contributions	-	-	-	-	-	(11)	(17)	(27)	(35)	(40)
Power factor correction plant	-	-	-	-	-	1	1	2	3	3
EDB-owned mobile substations and generators	-	-	-	-	-	-	-	12	14	15
Non system fixed assets										
Office Buildings	-	-	-	-	-	28	31	33	36	39
Information and Technology Systems	-	-	-	-	-	148	429	837	1,475	2,990
Office Furniture and Equipment	-	-	-	-	-	169	234	324	461	694
Tools, Plant and Machinery	-	-	-	-	-	10	24	41	66	101
Vehicles	-	-	-	-	-	51	82	158	275	483
Total	-	-	-	-	-	621	1,221	2,073	3,232	5,512

Appendix 16

Engineer's Report on Non Standard Asset Lives

Independent Engineer's Report – Asset life for 'peak load and mobile generation' and 'power factor correction' assets



Client: Orion New Zealand Ltd.

FINAL Report

DECEMBER 2012

LINETECH
Consulting

Prepared for

ORION NZ Ltd

Prepared by

LineTech Consulting Ltd



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Quality Information

Document Independent Engineer’s Report – Quality Standard Variation

Reference: LTC

Date: 13th December 2012

Prepared by: **Ir G. Richard Gibbons**
 BSc. (Hons), Dip BA, Cert Co Dir; FIET, C.Eng (UK); FIPENZ, CPEng (NZ);
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Revision History

Revision	Revision Date	Details	Authorised	
			Name/Position	Signature
Draft V1	13/12/12	Initial Draft for comment	R Gibbons/GM	
Final	20/12/12	Final version	R Gibbons/GM	

Executive Summary

Orion New Zealand Ltd (Orion) is preparing a “customised price-quality path” (CPP) application to be submitted to the Commerce Commission (Commission). This follows the significant damage to its infrastructure caused by the series of earthquakes affecting the Christchurch area that started on 4 September 2010. This document is submitted under the catastrophic event provisions of the Commerce Act Electricity Distribution Input Methodology Determination, December 2010.

One aspect where an independent engineers view is required relates to the service lives that should be allocated to components for which an existing standard life does not exist. Orion has two cases where there are no existing standard lives being ‘peak load and mobile generation’ and ‘power factor correction’.

This report considered the approaches adopted and the values proposed for adoption for each of these assets classes.

On the basis of the analysis undertaken this review supports the service lives proposed by Orion for ‘peak load and mobile generation’ and ‘power factor correction’ assets of 15 years and 35 years respectively.

Contents

Executive Summary.....	iii
1.0 Background/Introduction	5
2.0 Requirements.....	5
3.0 Generators	5
4.0 Power Factor Correction Capacitors	6
6.0 Conclusions	7
Appendix A: List of Documents Provided for Review	8

1.0 Background/Introduction

Orion New Zealand Ltd (Orion) is preparing a “customised price-quality path” (CPP) application to be submitted to the Commerce Commission (Commission).

This application is under section 53Q of the Act, which allows for a supplier of electricity distribution services, such as Orion, to make a proposal to the Commission for a CPP which effectively permits the supplier to follow a different price-quality path from the default price-quality path that would otherwise apply. A CPP proposal must be made in accordance with the methodologies and processes set out in the Input Methodology Determination.

Following the significant damage to its infrastructure caused by the series of earthquakes affecting the Christchurch area that started on 4 September 2010, Orion proposes to submit a CPP application to the Commission under the catastrophic event provisions of the Input Methodology Determination.

The Input Methodology Determination requires Orion to engage an independent engineer, to provide reports on certain aspects of that application. One aspect relates to the option of selecting alternative depreciation methodologies where clause 7.2 states an alternative depreciation method in accordance with 5.3.8 must be independently reviewed. Clause G9 of the Determination requires an independent verifier to provide an opinion as to whether the proposed asset life and proposed alternative depreciation method in the CPP application better meets the purposes of Part 4 of the Act than if the standard depreciation method set by the Commission was applied.

The alternative depreciation proposed by Orion does not involve them proposing alternative asset life thus it does not require verification or an engineer’s report. However Orion do require an independent engineer to provide a report on their proposed assessment of the physical service life of ‘peak load and mobile’ generators and power factor correction plants which they will commission between FY10 and FY 19 as they do not have a standard physical asset life.

This report has been prepared to review the proposed physical service lives for the identified plant

2.0 Requirements

The issue to be addressed is “are the proposed assessment of the physical service life of ‘peak load and mobile’ generators and power factor correction plants reasonable”

3.0 Generators

Orion propose to use an asset life of 15 years for these assets as they had some standby generators in the initial RAB, and had previously adopted an asset life of 16 years consistent with the IRD scheduled life for these assets. Since they expect to use the new mobile generation assets more frequently than the standby generators, they considered a shorter life to be appropriate.

To determine if this is reasonable the list of proposed assets was reviewed which identified some units rated at 2.0MVA (primarily used for peak lopping duties) but the majority of units being less than 300kVA, mainly mobile (Truck or trailer mounted) units. The expected operating hours was also provided for each set.

From an engineering perspective the lives of such plant are normally measured by the hours of operation, not the age of the machine. There are many factors which impact on the service life of such generators including their design, their operational speed, loading patterns, levels of maintenance, availability of parts, etc. larger slow speed machines that are carefully serviced run on base load can have an almost indefinite life, whereas very small high speed portable machines have had lives reported as low as 600hrs.

The IRD depreciation life represents a typical medium size generator in regular, but not continuous, use.

After considering the machines identified and their intended use as well as their expected annual hours of operation it is considered that the proposed service life of 15 years, slightly under the standard IRD life of 16 years, is reasonable and appropriate.

4.0 Power Factor Correction Capacitors

Orion has proposed to use an asset life of 35 years for these assets. The assets consist of arrangements of 11kV capacitors, switchgear and cables, protection and control relays and concrete pad enclosures. Orion propose to make the asset life for power factor correction assets a weighted average of the lives used for each of the components.

There already exist IM standard lives for each of these components on an individual basis, except for the 11kV capacitors. For the 11kV capacitors Orion have proposed to use the standard life for Ripple injection plant, of which one major component is such 11kV capacitors.

Considering firstly the proposal to use the weighted average of the lives of the individual components, this is a totally logical approach to the issue and is supported by this review. It is noted that the calculated average value for the life of the assembly was 32.9 yrs which has been rounded to 35years which in view of the averaged values for individual component lives is considered appropriate.

The second issue to consider is that of the appropriate life allocated to the capacitors. The proposal by Orion to adopt the standard IM life for ripple injection plant is logical from the viewpoint that this is the main other location where such items are used, however the ripple plant life reflects the average values for several components in addition to the capacitors such as inductors, switches, the coupling transformer as well as the signal generation plant which is normally an electronic unit. This latter item does not operate at 11kV and thus may distort the average life of the assembly.

A review of manufacturers literature for 11kV capacitors has identified that they are typically quoted as having a service life of 20years, which is in fact the same as the IM life for the complete ripple injection plant as proposed by Orion.

Thus the proposed composite life for 11kV Power factor correction capacitors of 35 years is considered to be a reasonable and appropriate life.

5.0 Conclusions

On the basis of the analysis undertaken this review supports the service lives proposed by Orion for 'peak load and mobile generation' and 'power factor correction' assets of 15 years and 35 years respectively.

Appendix A: List of Documents Provided for Review

The following Documents were supplied to support the review: -

- Spreadsheet of generation assets, including estimates of the number of operation hours each year.

Appendix 17

Recoverable costs - verifier

1. Verifier RFP
2. Verifier ToE
3. Verifier Tripartite Deed
4. Verifier Invoice 1 – to 31 November 2012
5. Verifier Invoice 2 – to 31 December 2012

Direct dial: 03 363 9848
Email: David.Freeman-Greene@oriongroup.co.nz

by email

12 June 2012

Geoff Brown
77 Taylors Road
Mount Albert
Auckland

Dear Geoff

Request for proposal relating to verification services

Introduction

- 1 Orion New Zealand Limited (*Orion*) wishes to engage an appropriate expert to act as “verifier” of a potential “customised price-quality path” (CPP) to be submitted to the Commerce Commission (*Commission*). This letter invites you to submit a proposal to act as that verifier.

Background

- 2 Orion owns and operates the electricity distribution network in central Canterbury between the Waimakariri and Rakaia rivers, and from the Canterbury coast to Arthur's Pass. Orion also owns the electrical contracting business Connectics.
- 3 Orion is a New Zealand electricity distribution services company. Under Part 4 of the Commerce Act 1986 (Act)¹, the Commission may impose regulation of the price and/or quality of goods or services supplied in markets where there is little or no likelihood of a substantial increase of competition. The Commission produces input methodologies in respect of such markets, which set out rules, requirements and processes applying to the regulation of those services.
- 4 The Commission has made a final determination as to the input methodologies applicable to electricity distribution services - the Commerce Act (Electricity Distribution Services Input Methodologies) Determination 2010 (Determination). The Determination sets out methodologies which must be applied by the Commission in order to regulate the price and quality of electricity distribution services Orion provides. A copy of the Determination (and the related “Reasons Paper”) can be found here: <http://www.comcom.govt.nz/electricity-distribution/>.

¹http://www.legislation.co.nz/act/public/1986/0005/latest/DLM87623.html?search=ta_act_C_ac%40acur%40anif_an%40bn%40rn_25_a&p=4



- 5 Under section 53Q of the Act, a supplier of electricity distribution services such as Orion may make a proposal to the Commission for a CPP which effectively permits the supplier to follow a different price-quality path from the default price-quality path that would otherwise apply. A CPP proposal must be made in accordance with the methodologies and processes set out in the Determination.
- 6 Following the significant damage to its infrastructure caused by the series of earthquakes affecting the Christchurch area that started on the 4th September 2010, Orion proposes to submit a CPP application to the Commission under the catastrophic event provisions of the Determination.
- 7 For the purposes of that application, the Determination requires Orion to engage a verifier, that the Commission has approved, to “verify” certain aspects of that application. The role of, and requirements for appointment of, a verifier are set out in clause 5.5.2 and Schedules F and G of the Determination. In particular, once the Commission has approved a proposed verifier, the approved person may not undertake any service in relation to the Orion’s CPP proposal until Orion, the Commission and the verifier have entered into a tripartite deed addressing the matters referred to in clause F5 of Schedule F. The form of tripartite deed proposed by Orion is accordingly enclosed. This has yet to be approved by the Commission and is subject to such amendments as may be required by the Commission.
- 8 Orion has not yet completed preparation of its draft CPP proposal. It anticipates doing so by Friday 16th November 2012. The final date for submission of the CPP application, which must be accompanied by a finalised verification report, is 11 February 2013. The timeframe for verification is accordingly short.
- 9 Further the Commission will require the verifier to be available following submission of the CPP proposal, to answer any questions it may have.

Request for proposal

- 10 You have indicated that you are interested in being appointed as verifier for Orion’s CPP proposal. Orion accordingly now requests, on and subject to the terms of this letter, that you submit to it your proposal to act in that role.
- 11 Your proposal should address at least the following matters:
 - 11.1 Your name and contact details.
 - 11.2 Confirmation of your willingness to act as verifier.
 - 11.3 Confirmation that you have read and understood, and agree to, the terms and conditions of this letter.
 - 11.4 Reasons why you are sufficiently qualified and experienced to carry out the role of verifier in accordance with the Determination, and an explanation of the

nature and extent of your qualifications and experience (and those of your relevant personnel) relevant to carrying out that role, including:

- (a) details of the key personnel who you anticipate would be involved (including details of their relevant experience);
 - (b) the other resources available to you to conduct the work, including other personnel that can cover for the key personnel identified above;
 - (c) other relevant recent work (including reasonable details of the work performed (including as to complexity and timing) and the names and contact details of at least 3 referees with whom you worked);
 - (d) conformation of the applicable standards issued and the applicable standards body that you will conduct your assignment as Verifier in accordance with; and
 - (e) confirmation that you can meet the requirements for independence set out in the determination.
- 11.5 Confirmation of your (and your relevant personnel's) availability to act as verifier and ability to meet the tight timing requirements noted above.
- 11.6 Confirmation that key personnel will not change without the approval of Orion, such approval not to be unreasonably withheld.
- 11.7 Confirmation that you can complete the following tasks in the timeframes stated:
- (a) notify Orion of the outcome of your selection, in accordance with clause G3 of Schedule G of the Determination, of Projects or Programmes meeting paragraph (c) of the definition in clause D1 of Schedule D of the Determination of "Identified Programme"; by 21 November 2012
 - (b) prepare a draft verification report in accordance with Schedule G of the Determination and provide it to Orion; by 21 December 2012
 - (c) prepare a verification report in accordance in accordance with Schedule G of the Determination that takes account of any modifications to the information originally provided to the Verifier under clause 2, in light of Orion's consideration of the draft verification report provided to it in accordance with clause 4.1(c); by 31 January 2103
 - (d) provide a certificate as described in clause 5.1.3(1)(b)(iii) of the Determination; by 31 January 2013
- 11.8 Include a written statement signed by you that can be supplied by Orion to the Commission that confirming that you are, and will be, independent (in the sense required by clause F2 of the Schedule F of the Determination), including:

- (a) a confirmation of the matters referred to in clause F2(2)(a); and
 - (b) any explanation required by clause F2(2)(b).
- 11.9 Include written statement signed by you that can be supplied by Orion to the Commission (as required by clause F3(2)) explaining the nature and extent of your qualifications and experience relevant to assessing and reporting on the CPP proposal in accordance with the tasks and duties specified in Schedule G.
- 11.10 Any potential impediments to your completing verification within the required timeframe.
- 11.11 Confirmation of your willingness to enter into the tripartite deed in the form **enclosed**, subject to reasonable amendments required by the Commission.
- 11.12 The fee basis upon which you would propose to charge for this work, including:
- (a) an estimate of the probable total fee (if expressed as a range then with no greater variance between the upper and lower bounds than 25% of the lower bound); and
 - (b) the key assumptions on which that estimate is based, including but not limited to:
 - (i) Schedule of hourly rates for individuals proposed
 - (ii) Other fees/charges
 - (iii) Estimates of the time inputs for key tasks.
- 11.13 The other terms and conditions you propose for the engagement. (Please note that such terms of engagement may supplement, but may not be inconsistent with, the tripartite deed.)
- 11.14 How you would expect to carry out your role, addressing in particular the following matters:
- (a) What assessment techniques are expected to be used when undertaking analysis and reviews of information and considering the matters required by Schedule G of the Determination for each for the following topics:
 - (i) Service categories, measures and levels
 - (ii) Forecast capex projects and programmes, including the techniques which are expected to be used for identified programmes
 - (iii) Forecast opex projects and programmes, including the techniques which are expected to be used for identified programmes

(iv) Unit rates and contingencies included in project and programme forecasts

(v) Demand forecasts.

12 Your proposal should be:

12.1 signed by you (or by your duly authorised agent) and include appropriate contact details, including postal and email addresses and telephone numbers;

12.2 delivered prior to 4pm on Friday 29th June 2012 (the *Closing Date*) by email (with subject line "*Verifier Proposal*") to: David.Freeman-Greene@Oriongroup.co.nz.

13 Submission of your proposal will constitute your agreement to the terms of this letter. Please ensure you have read and familiarised yourself with these provisions.

Submission of proposal

14 You may request additional information from Orion which you require for the preparation of a proposal. Any such material will or may, at Orion's option, be provided to one or more other persons from whom Orion has requested a proposal to act as verifier. However, you are and shall be responsible for the accuracy and sufficiency of your proposal (including the pricing and other information contained in it). You shall meet all costs you incur in considering this request and in preparing and submitting any proposal. You acknowledge that Orion may rely on the information in your proposal in relation to decisions it makes in relation to its CPP proposal and (in particular) verification of it, and you will accordingly exercise reasonable care in the preparation of any proposal and ensure that it is not misleading.

15 Any proposal submitted by you will be the property of and will be retained by Orion, and may be used by it for any purpose. Submission of a proposal by you will constitute your irrevocable confirmation that no intellectual property rights of any person will be infringed by:

15.1 receipt of that proposal by Orion, and use or disclosure of it by Orion for the purposes of assessing your proposal and/or obtaining the approval of the Commission to your appointment as verifier; or

15.2 use and disclosure by Orion for any other purpose of any part of that proposal (other than any part specifically identified in the proposal as the intellectual property of a third party which may not be used or disclosed by Orion for any purpose other than that in the immediately preceding sub-paragraph).

16 Notwithstanding the immediately preceding paragraph, Orion will not disclose your pricing proposal or your proposed terms of engagement to any person without your prior written consent, except to the extent (if any) that:

- 16.1 it reasonably requires to do so for the purposes of assessing your proposal and/or obtaining the approval of the Commission to your appointment as verifier;
- 16.2 it is required to do so by law; or
- 16.3 that information is already in or subsequently enters the public domain (otherwise than as a result of a breach by Orion of any obligation of confidentiality, including under the foregoing provisions of this clause).

Proposal acceptance period

- 17 Once submitted, your proposal will remain open for acceptance by Orion for a period of 40 working days from the Closing Date. Your proposal will be irrevocable and may not be withdrawn or amended during that period without Orion's written consent.

Subject to contract

- 18 Orion will have no legal or other obligations to you in relation to the conduct or outcome of this proposal process. Such obligations will only arise (if ever) upon acceptance of a proposal by Orion pursuant to paragraphs 21 to 24 of this letter and subsequent entry by you and Orion into a binding agreement.

Orion's rights

- 19 Orion may at any time, in each case without giving any reasons:
 - 19.1 invite one or more other parties to submit proposals relating to verification of Orion's CPP proposal and/or any other matter, without notice to you;
 - 19.2 accept, not accept or reject your proposal, whether in whole or in part and whether received before or after the Closing Date;
 - 19.3 consider any non-conforming or partially completed proposal submitted by you or any other person;
 - 19.4 enter into discussions and/or negotiations with any other person in relation to the verification of its CPP proposal and/or any other matters (on any terms) to the exclusion of, and without notice to, you and without the need to consider any resubmitted altered proposal documents (or any other material) from you;
 - 19.5 enter into any agreement or arrangement with any other person in relation to the verification of its CPP proposal and/or any other matters on any terms and conditions to the exclusion of, and without notice to, you and without the need to consider any resubmitted altered proposal documents (or any other material) from you;
 - 19.6 amend, suspend or cancel (in whole or in part) this request for proposal or any process relating to Orion's CPP proposal (including, to avoid doubt, elect not to proceed with a CPP application); and/or

- 19.7 act in any other manner it wishes in relation to its intended CPP proposal without any requirement to notify you or obtain your consent or approval.

Evaluation Process

- 20 Orion may take into consideration any matters that it considers relevant to the evaluation of a proposal from you and/or any other person (each a “tenderer”), including:
- 20.1 the Commission’s approval of the tenderer as a verifier
 - 20.2 the tenderer’s apparent capability to meet the desired outcomes.
 - 20.3 the experience and expertise of the tenderer.
 - 20.4 the quality of the tenderer’s response on all or any matters set out in the Proposal Documents.
 - 20.5 the completeness of the tenderer’s proposal.
 - 20.6 interviews with the tenderer.
 - 20.7 any other factors Orion considers relevant or appropriate.

Acceptance of proposal

- 21 Orion’s acceptance of your proposal is conditional on the Commission’s approval of you as a verifier and preparedness to enter into a tripartite deed with you and Orion in a form acceptable to Orion. If Orion accepts your proposal, it will give you notice of such acceptance in writing signed by an authorised signatory of Orion. Such notice will be sent to the address provided in your proposal. Acceptance will be deemed to have been communicated on the dispatch of that notice.
- 22 If Orion encloses with or attaches to that notice your proposed terms of engagement (or such amended terms of engagement as may have been agreed between you and Orion subsequent to receipt by Orion of your proposal) duly executed by Orion, and the tripartite deed in the form agreed with you, you will immediately execute those terms and that deed and return them to Orion.
- 23 If Orion does not do so, you will immediately negotiate in good faith with Orion in an endeavour to agree the terms and conditions of your engagement and/or the deed (as applicable) as soon as possible.
- 24 If your proposal is unsuccessful, Orion will notify you of that fact.

No liability

- 25 Orion makes no representation and gives no warranty (and you will not allege that Orion has made any representation or given any warranty), and will have no liability, in relation to the accuracy or sufficiency of, or for any errors or misdescriptions in, this

letter, its accompanying documentation or any other information provided by Orion in relation to your possible appointment as verifier.

- 26 You agree that Orion has no liability whatsoever to you at law, by statute, in equity, in tort (including negligence) or otherwise, in connection with this letter, its accompanying documentation or the process relating to the possible appointment of a verifier by Orion, except to the extent (if any) expressly agreed in writing by Orion.
- 27 If, despite the other provisions of this letter, Orion is found to be liable to you then its liability is limited to NZ\$100.

Confidentiality

- 28 You must keep confidential (and your receipt and acceptance of this letter shall constitute your agreement to keep confidential) all information contained in this letter and its accompanying documents, except to the extent that:
- 28.1 Orion agrees otherwise in writing;
 - 28.2 you are required by law to disclose that information; or
 - 28.3 the information is already in or subsequently enters the public domain other than through a breach by you of any obligation of confidence (whether in this letter or otherwise).

Yours faithfully



David Freeman-Greene
General Manager Commercial

Terms of Engagement

Date:

PARTIES

Geoff Brown and Associates Limited (*Verifier*)

Orion New Zealand Limited (*Orion*)

BACKGROUND

- A Pursuant to Part 4 of the Commerce Act 1986 (*Act*), the Commerce Commission (*Commission*) has made the Commerce Act (Electricity Distribution Services Input Methodologies) Determination 2010 (*Determination*). The Determination includes rules and processes which must be applied by the Commission in its regulation of the price and quality of electricity distribution services provided by Orion.
- B Under the Act, Orion may make a proposal to the Commission for a customised price-quality path (*CPP*).
- C In connection with such proposal, Orion must engage a verifier to carry out the role set out in Schedules F and G of the Determination. Accordingly, Orion wishes to engage the Verifier to conduct the verification services required by the Determination (the *Review*). This agreement sets out the terms and conditions of that engagement.
- D Orion, the Commission and the Verifier must also enter into a Tripartite Deed (*the Deed*) in accordance with Schedule F of the Determination.

THE PARTIES AGREE as follows:

1 TERM

This agreement will commence on 1 September 2012 and continue in force until terminated in accordance with clause 8.

2 SERVICES

- 2.1 The Verifier will provide the services set out in Schedule 1 (the *Services*) in accordance with the requirements of this agreement. The Services will be performed at all times in accordance with clause 5.5.2 and Schedules F and G of the Determination. If any work performed by the Verifier is defective or fails to meet one or more requirements of this agreement, then the Verifier will promptly remedy that defect or failure at no charge to Orion.
- 2.2 Subject to the confidentiality, security and operational requirements of Orion, the Verifier will be allowed access to relevant premises and information as reasonably necessary for the performance of the Services, at reasonable times on reasonable notice. The Verifier will ensure that disruption to Orion is minimised.
- 2.3 The Verifier will perform the Services using the personnel named in Schedule 1 (each a *Subcontractor*). The Verifier will not substitute any other person to carry out the Services without Orion's prior written consent.
- 2.4 The Verifier will ensure that the Subcontractors perform the Services to the best of their skill, knowledge and experience, using due diligence and care, and in accordance with Orion's reasonable and lawful directions in relation to the Services. For the purposes of this

agreement, all the acts and omissions of the Subcontractors in connection with the Services will also be attributed to the Verifier. Nothing in this clause 2.4 shall require the Verifier or any of its Subcontractors to act other than in accordance with the Deed.

- 2.5 If Orion decides on reasonable grounds that any particular Subcontractor is unsuitable, Orion may require the Verifier to have that person replaced, at no cost to Orion. If for any reason a Subcontractor is unable to perform the Services, the Verifier will promptly engage a replacement Subcontractor who is suitably qualified, competent and acceptable in all respects to Orion, to perform the Services.
- 2.6 From time to time during the term of this agreement, Orion may submit a written request to the Verifier seeking a change to the scope, timeframes, outputs, or any other aspect, of the Services (including, but not limited to, any change arising out of a change to Orion's CPP proposal in accordance with clause 4.2 of the Deed). The Verifier will respond promptly and in writing to each such request, and will not unreasonably withhold its consent to any such request, including by demanding any unreasonable conditions or charges in relation to that consent. Once Orion and the Verifier have agreed any such request in writing, this agreement will be deemed to have been amended accordingly.
- 2.7 Upon written request from Orion, the Verifier must, as soon as reasonably practicable:
- (a) confirm in writing whether all information requested by the Verifier in connection with the Review was provided by Orion; and
 - (b) to the extent such information was not provided by Orion, the Verifier must provide a detailed description of the information that was not provided following the Verifier's request.

3 PAYMENT

- 3.1 Subject to the performance of the Services to Orion's reasonable satisfaction, Orion will pay the Verifier the fees and expenses specified in Schedule 2, in accordance with this clause 3.
- 3.2 In addition to any consideration payable for a supply made under this agreement by the Verifier, Orion will pay to the Verifier an amount equal to the GST charged on that supply upon receipt of a tax invoice as defined in the Goods and Services Tax Act 1985 (**GST Act**) from the Verifier with respect to the supply.
- 3.3 If a payment under or in connection with this agreement (excluding the fees in clause 2, Schedule 2) is expressly calculated in this agreement by reference to an expense, cost, loss or outgoing (**Relevant Expense**) of any person, then notwithstanding anything else in this agreement, the amount of the Relevant Expense for the purpose of calculating the payment is the Relevant Expense reduced by an amount equal to any credit for input tax or other deduction from output tax under the GST Act available in respect of it.
- 3.4 The Verifier will present a valid tax invoice to Orion monthly in relation to the Services performed during the immediately preceding month in accordance with clause 4 of Schedule 2. Orion will pay the Verifier the amount due under the tax invoice on or before the 20th of the month following Orion's receipt of the tax invoice.
- 3.5 The amounts payable to the Verifier under this agreement will be paid net of, and without any obligation on Orion to make any additional payment by way of, indemnity, gross-up or otherwise for, any withholding or deduction for or on account of any taxes.
- 3.6 The Verifier will not be entitled to any remuneration or reimbursement beyond the amounts payable under this clause 3. The Verifier will be solely responsible for the payment of all levies, premiums, assessments, taxes or other payments levied upon the Verifier as

required under the provisions of the Income Tax Act 2007, the GST Act, the Accident Compensation Act 2001, and all other legislation which may be in force and relates to or affects the performance of the Services.

4 OWNERSHIP OF DELIVERABLES

- 4.1 The Verifier acknowledges that any work, product, data, document, record, paper or other intellectual property produced in the course of performing the Services by or for the Verifier (either alone or jointly with Orion) will be Orion's exclusive property, and the Verifier will take all steps necessary to ensure that all intellectual property rights arising in the creation of that work are either vested in Orion as and when they arise or assigned to Orion as soon as possible thereafter upon any written request by Orion.
- 4.2 The Verifier will ensure that each Subcontractor waives his or her author's and moral rights in each and every part of the work produced under this agreement.

5 CONFIDENTIALITY

- 5.1 Subject to clause 5.2, the Verifier acknowledges that it may acquire confidential information relating to Orion (including about its business, clients and customers) in the course of providing the Services (***Orion Confidential Information***). The Verifier shall keep all Orion Confidential Information strictly confidential at all times, and acknowledges that it holds the Orion Confidential Information on trust for Orion and must never use, or attempt to use, the Orion Confidential Information for any purposes other than the fulfilment of its obligations under this agreement.
- 5.2 The Verifier may disclose Orion Confidential Information (or use it for other purposes) to the extent (if any):
- (a) that disclosure occurs as a result of the Verifier complying with the terms of the Deed or the Determination;
 - (b) that Orion agrees in writing to such disclosure or use;
 - (c) required by this agreement or any applicable law; or
 - (d) that Orion Confidential Information enters the public domain (otherwise than as a result of a breach by the Verifier of its obligations set out in clause 5.1 or any other obligation of confidence).
- 5.3 Unless required by law, the Verifier will not make any public announcements relating to the Review, except with Orion's prior written consent.

6 VERIFIER'S UNDERTAKINGS

The Verifier undertakes and represents to Orion that:

- (a) all representations of fact set out in the Consultancy Proposal dated 23 July 2012 are accurate, reasonably complete and not misleading;
- (b) the Verifier and each Subcontractor has the expertise, qualifications and experience necessary to perform the Services;
- (c) neither the Verifier nor any Subcontractor will make any statement or produce any material in connection with the Review that is deceptive, misleading or defamatory of Orion, whether in a report or other document produced under this agreement or in any other context;

- (d) except as disclosed in writing to Orion prior to the commencement of the Services, neither the Verifier nor any of the Subcontractors nor any of their immediate family members have any direct or indirect personal relationship, affiliation or association with Orion, or any of its respective affiliates that might create or might reasonably be anticipated to create any actual or perceived conflict of interest with the provision of the Services in an objective, transparent and independent manner;
- (e) if after the date of this agreement circumstances arise which would have constituted a breach of the undertaking in sub-clause (d) had they existed at the date of this agreement, the Verifier will promptly disclose those circumstances to Orion in writing, and take any steps reasonably requested by Orion to reduce or avoid any actual or perceived conflict of interest;
- (f) the Verifier and each Subcontractor will comply with all laws applicable to their respective activities (including the Determination) in connection with the Services; and
- (g) while on the premises of Orion, the Verifier and each Subcontractor will comply with any reasonable security and health & safety policies or procedures notified to the Verifier in writing from time to time, by Orion or its suppliers (as the case may be).

7 PRIORITY

- 7.1 If there is a conflict between any parts of the Deed and this agreement, the terms of the Deed shall prevail.
- 7.2 If there is a conflict between any parts of this agreement, for the purposes of interpretation, the parts of this agreement rank in the following descending order of priority, with each lower part to be disregarded to the extent that it conflicts with a higher ranking part:
 - (a) clauses 1 to 12;
 - (b) Schedule 2; and
 - (c) Schedule 1.

8 TERMINATION

- 8.1 If the Deed expires or is terminated in accordance with clause 5.1 and 5.2 of the Deed, this agreement shall automatically be terminated as at the same date as the date of expiration or termination of the Deed.
- 8.2 On or at any time after the termination of this agreement, if requested by Orion, the Verifier will promptly deliver to Orion in a reasonably useable format all data, documents, records and papers gathered or produced in the course of (or for the purposes of) the Services, to the extent these are in the possession or control of the Verifier and/or any Subcontractor. Following delivery to Orion, the Verifier will promptly ensure the destruction of all copies of such data, documents, records and papers retained by the Verifier or any Subcontractor, and will certify that destruction in writing to Orion.
- 8.3 If at any time following termination of this agreement, any matters or materials considered or produced by the Verifier during the performance of the Services become relevant to a dispute between Orion and a third party, then if requested by Orion, the Verifier will recommence its engagement under the terms and conditions of this Agreement to provide additional services to Orion in connection its conduct of the dispute, for such further period as Orion may reasonably require, with the details of those services to be agreed by the parties in accordance with clause 2.6.

8.4 Clauses 4, 5, 7, 8.2, 8.3, 9, 10, 11 and 12 will survive any termination or expiry of this agreement. Termination or expiry will not affect accrued claims and liabilities.

9 LIABILITY

9.1 The total aggregate liability of the Verifier to Orion under or in connection with this agreement will not in any circumstances exceed five times the total of all fees and expenses paid and/or payable by Orion to the Verifier under this agreement.

9.2 The total aggregate liability of Orion to the Verifier under or in connection with this agreement will not in any circumstances exceed the total of all fees and expenses paid and/or payable by Orion to the Verifier under this agreement.

9.3 Except where this agreement provides otherwise, the limitations and exclusions in this clause 9 are intended to apply to all liability however it may arise, regardless of the cause of the liability and irrespective of the legal basis for that liability, whether under the law of contract, equity or tort (including negligence), under statute, or on any other legal basis.

10 DISPUTES

10.1 If any difference or dispute arises concerning or relating to this agreement, either party may give written notice to the other outlining the difference or dispute (**Dispute Notice**), in which case Orion and the Verifier will meet as soon as reasonably practicable to discuss that difference or dispute, actively, openly and in good faith, with a view to resolving it by mutual agreement.

10.2 If the difference or dispute has not been resolved within 14 days of receipt of the Dispute Notice, then either party may refer the matter to mediation. If the dispute has not been resolved within 28 days of receipt of the Dispute Notice, then either party may refer the dispute to final and binding resolution by arbitration under the Arbitration Act 1996.

10.3 If a difference or dispute arises concerning or relating to this agreement and the same difference or dispute has arisen under the Deed, the parties agree that resolution of the difference or dispute under this agreement shall be deferred until the difference or dispute has been resolved under the Deed.

11 NATURE OF THIS AGREEMENT

11.1 In providing the Services, both the Verifier and the Subcontractors are, in all respects, independent contractors and not Orion's employees, and the Verifier and Subcontractors will be solely liable for all of their respective debts, losses, expenses, ACC levies and taxation on income.

11.2 This agreement does not create an employment, fiduciary, partnership, agency or joint venture relationship either between Orion and the Verifier, or between Orion and any Subcontractor. Unless Orion agrees otherwise in writing, neither the Verifier nor the Subcontractors are authorised to bind Orion or to act on its behalf.

12 MISCELLANEOUS

12.1 In the construction of this agreement, unless the context requires otherwise: a reference to a party to this agreement includes that party's personal representatives, successors and permitted assigns; a reference to a person includes a corporation sole and also a body of persons, whether corporate or unincorporate; the schedules form part of this agreement; a reference to an enactment or any regulations is a reference to that enactment or those regulations as amended or replaced from time to time; and a reference to "written" or "in

writing" includes all modes of presenting or reproducing words, figures and symbols in a tangible and permanently visible form; and any reference to \$ is to New Zealand dollars.

- 12.2 Any change to this agreement must be in writing and must be signed by a duly authorised representative of each party. Any delay or failure by any party to exercise a right under this document does not operate as a waiver and the single or partial exercise of any right by that party does not preclude any other or further exercise of that or any other right by that party.
- 12.3 This agreement constitutes the complete statement of the agreement between the parties relating to the Services, and supersedes all of their previous agreements and understandings on that subject, whether oral or written (other than the Deed).
- 12.4 Neither party can assign or transfer any of its rights or obligations under this agreement to any other person without the prior written consent of the other party.
- 12.5 Each party will, at its own expense and when requested by the other party, promptly do, sign and deliver everything reasonably required for the purposes of and to give full effect to this agreement.
- 12.6 This document will be, governed by the laws of New Zealand, and the parties submit to the non-exclusive jurisdiction of the courts of New Zealand.
- 12.7 This document may be executed in several counterparts (including facsimile or email copies), all of which when signed and taken together constitute a single agreement between the parties.

SIGNATURES

For **Orion New Zealand Limited** by:



Authorised Signatory

Dated: 17/8/12

For **Geoff Brown and Associates Limited**
by:



Authorised Signatory

Dated: 23-8-12

SCHEDULE 1 – SERVICES

1 Services

1.1 The services to be performed under this agreement are the verification services as described in the Consultancy Proposal prepared for Orion by Geoff Brown & Associates and dated 23 July 2012.

2 Subcontractors

2.1 The following personnel will perform the Services:

- (a) Geoff Brown
- (b) Chris Brennan
- (c) Malcolm Campbell
- (d) Pieter Nel

SCHEDULE 2 – FEES AND EXPENSES

1 Fees and expenses

1.1 The Services shall be charged on a time and expenses basis.

2 Fees

2.1 The fees for the time spent on the provision of the Services shall be calculated in accordance with the respective hourly rates for each Subcontractor specified below:

Subcontractor	Hourly Rate (ex GST)
Geoff Brown	██████
Chris Brennan	██████
Malcolm Campbell	██████
Pieter Nel	██████

2.2 No Subcontractor will charge more than 8 hours for any one day.

3 Expenses

3.1 **Actual and reasonable expenses:** Subject to clause 3.2 below, Orion will pay the Verifier actual and reasonable expenses incurred in the provision of the Services.

3.2 **Subsistence allowance:** If, in the performance of the Services, Subcontractors are required to travel a distance which reasonably requires the Subcontractor to spend the night away from their normal place of employment, Orion shall pay a fixed fee of \$70 per night spent away (excluding GST). For the avoidance of doubt, accommodation and travel expenses shall be covered by clause 3.1 above.

4 Invoice

4.1 The invoice provided by the Verifier must include a breakdown of the number of hours spent by each Subcontractor during the relevant month and provide details for each expense being claimed accompanied by a valid receipt, invoice or other acceptable evidence.

5 Estimate

5.1 The Verifier’s estimated fee and expenses range for the Services is ████████ to ████████ (including expenses but excluding GST). The midpoint for the estimate is thus ████████ (including expenses but excluding GST).

Tripartite Deed

Orion New Zealand Limited (Orion)

The Commerce Commission
(Commission)

Geoff Brown and Associates Limited
(Verifier)

TRIPARTITE DEED

Date: 5 Sept. 2012

PARTIES

Orion New Zealand Limited (*Orion*)

Commerce Commission (*Commission*)

Geoff Brown and Associates Limited (*Verifier*)

BACKGROUND

- A Orion is a New Zealand electricity distribution services company.
- B Pursuant to Part 4 of the Commerce Act 1986 (*Act*), the Commission has made the Commerce Act (Electricity Distribution Services Input Methodologies) Determination 2010 (*Determination*). The Determination includes rules and processes which must be applied by the Commission in its regulation of the price and quality of electricity distribution services provided by Orion.
- C Under the Act, Orion may make a proposal to the Commission for a customised price-quality path (CPP).
- D In connection with such proposal, Orion must engage a verifier to carry out the role set out in Schedules F and G of the Determination. Accordingly, Orion has engaged the Verifier on the terms of a letter agreement between them dated [•] (*Terms of Engagement*).
- E Orion proposes to submit a CPP application to the Commission under the Determination and, in accordance with Schedule F of the Determination, the parties have agreed to enter into this Deed.

BY THIS DEED the parties agree as follows:

1 DEFINITIONS AND CONSTRUCTION

1.1 Defined terms

In this deed terms capitalised but otherwise undefined have the meanings given to them in the Determination.

1.2 Construction

In the construction of this deed, unless the context requires otherwise:

Clauses: a reference to a clause of this deed unless otherwise stated;

Documents: a reference to any document, including this deed and the Determination, includes a reference to that document as amended or replaced from time to time;

Headings: headings appear as a matter of convenience and do not affect the construction of this deed;

No Contra Proferentem Construction: the rule of construction known as the contra proferentem rule does not apply to this deed;

Parties: a reference to a party to this deed or any other document includes that party's personal representatives/successors and permitted assigns;

Related Terms: where a word or expression is defined in this deed, other parts of speech and grammatical forms of that word or expression have corresponding meanings;

Singular, Plural and Gender: the singular includes the plural and vice versa, and words importing one gender include the other genders;

Statutes and Regulations: a reference to an enactment or any regulations is a reference to that enactment or those regulations as amended, or to any enactment or regulations substituted for that enactment or those regulations; and

Writing: a reference to "written" or "in writing" includes all modes of presenting or reproducing words, figures and symbols in a tangible and permanently visible form.

- 1.3 The parties acknowledge and agree that nothing in this Deed, or the Terms of Engagement, amend or replace the requirements set out in Schedule G of the Determination.

2 PROVISION OF INFORMATION

2.1 Orion shall:

- (a) as soon as reasonably practicable following entry into this deed provide the Verifier with the information specified in clause 5.5.2(3) of the Determination in accordance with that clause;
- (b) as soon as is reasonably practicable following the written request of the Verifier, provide the Verifier with:
 - (i) information required by Schedule D of the Determination to be identified (but not provided) in Orion's CPP Proposal; and any other information of which Orion is in possession and that is relevant (in the opinion of the Verifier, acting reasonably) to:
 - (A) the Verifier's obligation under sub-clause 4.1 to verify the relevant parts of Orion's CPP Proposal in accordance with the Terms of Engagement and Schedule G of the Determination;
 - (B) Electricity Distribution Services;

(C) any other Regulated Service relevant to Orion's CPP Proposal;
and

(D) any other Unregulated Service relevant to Orion's CPP Proposal,

for the purpose of the Verifier carrying out its obligations as set out in clause 4.1.

3 PAYMENT OF VERIFIER'S FEE

3.1 Orion shall pay the Verifier its fee for verifying the relevant parts of Orion's CPP Proposal in accordance with the Terms of Engagement and Schedule G of the Determination.

4 VERIFIER'S OBLIGATIONS

4.1 Verification of Orion's CPP Proposal

The Verifier will, subject to Orion complying with its obligations under this Deed:

- (a) verify the relevant parts of Orion's CPP Proposal in accordance with the Terms of Engagement and Schedule G of the Determination;
- (b) notify Orion of the outcome of its selection, in accordance with clause G3 of Schedule G of the Determination, of Projects or Programmes meeting paragraph (c) of the definition in clause D1 of Schedule D of the Determination of "Identified Programme";
- (c) prepare a draft verification report in accordance with Schedule G of the Determination and provide it to Orion;
- (d) prepare a verification report in accordance with Schedule G of the Determination that takes account of any modifications to the information originally provided to the Verifier under clause 2, in light of Orion's consideration of the draft verification report provided to it in accordance with clause 4.1(c);
- (e) provide a certificate as described in clause 5.1.3(1)(b)(iii) of the Determination;
- (f) be available to answer any questions posed by the Commission on the verification report referred to at clause 4.1(d), in person, by telephone or in writing, as reasonably required by the Commission.

4.2 Changes to Orion's CPP Proposal

In the event that the Commission makes or requires, or Orion seeks to make, any changes to Orion's CPP Proposal following submission of the CPP Proposal to the Commission, the parties agree that, if so requested by Orion, the provisions of clause 4.1 shall apply (on such basis as the parties, each of which must act reasonably, agree in writing at the time having regard to the circumstances) in

relation to some or all those changes or to the changed CPP Proposal (as specified by Orion).

4.3 Duty of care

The Verifier acknowledges that, in carrying out its obligations under clause 4.1 and 4.2, it has a duty of care to the Commission.

5 COMMENCEMENT, EXPIRATION, AND TERMINATION

5.1 This deed commences upon execution and delivery by all parties, and expires on the earlier of the date:

- (a) Orion gives notice to the Verifier and the Commission that it no longer intends to submit its CPP Proposal to the Commission (for which purpose Orion will be deemed to have given such notice on 17 February 2014 if it has not by then submitted an application for approval of a CPP Proposal);
- (b) the CPP Proposal (together with relevant changes (if any)) is approved by the Commission; or
- (c) the Commission notifies Orion that it will not approve Orion's CPP Proposal (whether in its original form or with amendments).

5.2 This deed may be terminated by mutual agreement of the parties in writing.

6 AMENDMENT

No amendment to this deed will be effective unless it is in writing and executed by all the parties.

7 COUNTERPARTS

This agreement may be executed in any number of counterparts. Once the parties have executed the counterparts, and each party has received a copy of each signed counterpart which that party did not execute, each counterpart will be deemed to be as valid and binding on the party executing it as if it had been executed by all the parties.

8 GOVERNING LAW

This agreement is governed by and construed in accordance with New Zealand law.

TRIPARTITE DEED

EXECUTED by the parties.

Signed on behalf of
Orion New Zealand Limited by:



Director



Director

Signed on behalf of
Geoff Brown and Associates Limited
by:



Sole Director

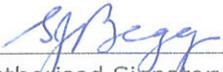

(Witness signature)

Freda Olive Gibson
Name

retired
Occupation

Auckland
(City of Residence)

Signed on behalf of
Commerce Commission by:



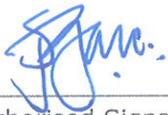
Authorised Signatory
Sue Begg
Deputy Chair, Commerce Commission

(Witness signature)

Name

Occupation

(City of Residence)



Authorised Signatory
Dr. Stephen Gale
Telecommunications Commissioner
Commerce Commission

(Witness signature)

Name

Occupation

(City of Residence)



OR038093

V02797

GEOFF BROWN & ASSOCIATES LTD

TAX INVOICE NO **222**
GST NO **81-633-428**

77 Taylors Rd
 Mt Albert
 Auckland 1025
 New Zealand

Ph/Fax 64-9-846 6004
 Mob 64-21-466 693
 Email geoff@gbassoc.com

Orion New Zealand Ltd
 P O Box 13 896
 Armagh
 Christchurch 8141

Date: 30 Nov 2012
 Client Ref:
 Our Ref:
 Period of Service: 1 Oct -30 Nov 2012

Attention: Dennis Jones

Verification of Orion's Customised Price Path Application	NZ Dollar
Fees	
As per attachment	67,775.00
Disbursements	
GST standard rated - as per attachment	3,636.63
GST zero rated - as per attachment	1,596.36
	
Sub-total	73,007.99
GST (see attachment)	10,711.74
Total	583,719.73

Z

Payment should be made to Geoff Brown & Associates Ltd and crossed "Not Negotiable" or direct credit to:

Account No: 12-3077-0479332-00
 ASB Bank
 St Lukes Branch
 Westfield Shoppingtown St Lukes
 St Lukes Rd
 Mt Albert
 Auckland, NZ.

J 200160 - 290980

Approved 10.12.12



GEOFF BROWN & ASSOCIATES LTD

TAX INVOICE NO 225
 GST NO 81-633-428

77 Taylors Rd
 Mt Albert
 Auckland 1025
 New Zealand

Ph/Fax 64-9-846 6004
 Mob 64-21-466 693
 Email geoff@gbassoc.com

Orion New Zealand Ltd
 P O Box 13 896
 Armagh
 Christchurch 8141

Date: 31 December 2012

Client Ref:

Our Ref:

Attention: Dennis Jones

Period of Service: 1-31 Dec 2012

Verification of Orion's Customised Price Path Application	NZ Dollar
Fees	
As per attachment	67,556.25
<i>J 200 160</i>	
<i>R 90 9310</i>	
<i>Approved</i>	
	
Sub-total	67,556.25
GST	10,133.44
<i>21 13 . 1. 13</i>	
Total	\$77,689.69

Payment should be made to Geoff Brown & Associates Ltd and crossed "Not Negotiable" or direct credit to:

Account No: 12-3077-0479332-00
 ASB Bank
 St Lukes Branch
 Westfield Shoppingtown St Lukes
 St Lukes Rd
 Mt Albert
 Auckland, NZ.

Appendix 18

Recoverable costs - auditor

1. Arrangements for assurance engagement
2. Audit Invoice 1 to 30 November 2012
3. Audit Invoice 2 to 31 December 2012

8 October 2012

PO Box 2, Christchurch 8140

www.auditnz.govt.nz

Freephone: 0508 AUDITNZ

(0508 283 4869)

Fax: 03 377 0167

Mr Paul Munro
Chairman
Audit committee
Orion New Zealand Limited
PO Box 13896
Christchurch 8141

Dear Paul

Arrangements for the assurance engagement in respect of Orion New Zealand Limited's customised price-quality path proposal

1 Introduction

This letter outlines our arrangements for performing the assurance engagement in respect of Orion New Zealand Limited's (Orion) customised price-quality path proposal.

In this letter, we cover the following key areas:

- terms of our engagement
- our areas of assurance emphasis
- our expectations with respect to quality and timeliness of information at the commencement of the assurance review, and
- logistics (timetable, fee, etc).

Acknowledgement

If you are in agreement with the arrangements, please sign and return the attached copy of this letter to us by 31 October 2012.

2 Terms of our engagement

We will conduct our engagement (the assurance review) in accordance with the Standard on Assurance Engagements 3100 - *Compliance Engagements* issued by the External Reporting Board.

The general terms of our engagement with Orion and our respective responsibilities are contained in our audit engagement letter of 3 November 2011, supplemented by the terms of the engagement that apply specifically to the assurance review of the Requirements as set out in Appendix 1.

3 Background to engagement

Following the impact of the Canterbury earthquakes, Orion has elected to apply for a customised price-quality path (CPP). The Commerce Commission has set out the requirements for a CPP proposal under Part 5 of the Commerce Act (Electricity Distribution Services Input Methodologies) Determination 2010 (the Determination). These are:

- the information required under subpart 4, including:
 - general matters, including the reasons for and priority of the proposal, and the duration of the regulatory period
 - information on the proposed quality standard variation
 - financial based information, including price path, cost allocation, asset valuation, tax, cost of capital, expenditure and prices
- evidence of consumer consultation, as set out in clause 5.5.1 of the Determination
- a series of reports accompanying the CPP proposal including the:
 - verification report prepared in accordance with schedule G
 - audit report prepared in accordance with clause 5.1.4, and
 - certification reports prepared in accordance with clause 5.5.4.

Orion's CPP proposal will contain both historical and prospective financial and non-financial information. The historical financial information will cover the periods from the year ended 31 March 2008 to 31 March 2012. The prospective information will cover the assessment period (the years ending 31 March 2013 and 2014) and the next period, the five years ending 31 March 2019.

Orion may elect to include historical financial and non financial information which extends beyond 2008.

Orion is required to submit its CPP proposal to the Commerce Commission by no later than 22 February 2013.

4 Areas of assurance emphasis

4.1 Scope of engagement

We will be focusing on Orion's compliance with the significant requirements of the Determination. The scope of our assurance engagement is set out in clause 5.5.3 of the Determination. It requires us to assess whether:

- Orion has proper records in place to compile the information required by Subpart 4 of the Determination.
- That financial information included in the CPP proposal is prepared in all material respects with the Determination.

- Information provided in spreadsheets is accurately presented. We are working with the OAG on what this means for our assurance review. 'Accurately presented' does not fit with the concept of materiality and clarification is required.

We will develop and apply our audit procedures to obtain assurance that the above requirements have been met.

In conducting our assurance engagement, we will consider:

- Orion's understanding of the Determination
- the process that Orion has gone through to comply with the Determination, and
- the quality assurance processes it has in place to provide management and the board with assurance that the Determination have been complied with.

We note that Orion has engaged PricewaterhouseCoopers to assist in compiling the CPP proposal. Where possible we will seek to place reliance on Orion's own processes, and assess the competence and evaluate the work completed by others, for example PricewaterhouseCoopers and the verifier.

4.2 Legislative compliance

As part of the Auditor-General's mandate, we will carry out a review of legislative compliance. This review is limited to obtaining assurance that Orion has complied with significant legislative requirements of the Determination. Our assurance review does not cover all of Orion's legislative compliance requirements.

Our approach to this will involve assessing the systems and procedures that Orion has in place to ensure compliance with the Determination. We will also complete our own review to confirm compliance with the key aspects of the Determination.

5 Our expectations with respect to the CPP proposal

To enable an efficient assurance review to be undertaken we expect that:

- Orion will enable Audit New Zealand's access to all relevant records, provide information in a timely manner and give the appropriate level of assistance from staff
- the information contained in the CPP proposal will be available in a timely manner during the assurance review and be fully supported by a detailed workpaper files, and
- information contained in the CPP proposal will be subjected to appropriate levels of quality review before submission for our review.

6 Logistics

6.1 Our review team

Our personnel involved in the management of this assurance engagement are:

Scott Tobin	Director
Ian Lothian	Professional Standards Review Director
Hugh Jory	Audit Manager
Ben Lo	Audit Supervisor
Alan Clifford	ISAA Director
Jason Biggins	Tax Director

6.2 Review and reporting timetable

Orion has requested that we complete our assurance engagement in two parts. The main part of our assurance engagement will review the draft CPP proposal and will be completed by the end of December 2012. We will also complete a review of the final CPP proposal, once Orion has had an opportunity to consider the findings from our initial review, the verifiers review, and the results of the consumer consultation.

Consequently, our planned timetable, subject to confirmation by Orion, is as follows:

	Date
CPP proposal models available for review	From mid October 2012
Review of CPP proposal models commences	From mid October 2012
Draft CPP proposal available for review	Mid November 2012
Stage 1 of assurance review commences	12 November 2012
Stage 1 of assurance review complete	End December 2012
Management letter on stage 1 review to the audit committee	Mid December 2012
Stage 2 of assurance review commences	4 February 2013
Assurance report issued	By 22 February 2013
Management letter on stage 2 review to the audit committee	By 22 February 2013

7 Professional fees

This is the first time that an electricity distribution business has elected to apply for a CPP. The information is complex and lengthy, and it is critical to ensure that the processes used are robust. Given that this is the first CPP completed, it is difficult to estimate a fee for our assurance review. Therefore, we propose to invoice the actual cost of completing the audit based on the actual hours incurred.

We have outlined the applicable charge-out rates for our planned audit team in Appendix 2. We will also regularly advise Orion of the costs we have incurred in auditing the CPP proposal.

8 General

We look forward to working in partnership with Orion's management in completing and reporting on this engagement.

If there are matters on this engagement that we could further clarify for you, please contact us.

Yours sincerely



Scott Tobin
Director

I acknowledge that this letter is in accordance with my understanding of the arrangements of the assurance engagement.

Signed



Date

24/10/12.

Mr Paul Munro
Chairman
Audit committee
Orion New Zealand Limited

Appendix 1: Terms of the engagement that apply specifically to the assurance engagement in respect of Orion New Zealand Limited's customised price-quality path proposal

Background

This supplement to the existing engagement letter dated 3 November 2011 is issued on behalf of the Auditor-General. The Auditor-General is the statutory auditor of Orion. The Auditor-General has appointed me, Scott Tobin, using the staff and resources of Audit New Zealand, to carry out the assurance review of Orion's customised price-quality path proposal (CPP proposal) made under Part 5 of the Commerce Act (Electricity Distribution Services Input Methodologies) Determination 2010 (hereinafter referred as the Determination). This review will be conducted in accordance with the Standard on Assurance Engagements 3100 – *Compliance Engagements* issued by the External Reporting Board.

The purpose of this letter is to supplement the existing engagement letter by outlining the terms of the engagement that apply specifically to the assurance review of Orion's CPP proposal. This supplement should be read in conjunction with the existing audit engagement letter.

Objectives

The objectives of the assurance review of the CPP proposal are:

- to provide a report in accordance with clause 5.1.4 of the Determination on the CPP proposal, and whether, in our assurance report:
 - as far as can appear from an examination of them, proper records to enable the complete and accurate compilation of information required by Subpart 4 of the Determination for the purpose of the CPP proposal have been kept by Orion
 - in the case of actual financial information relating to the current period, that information has been prepared in all material respects in accordance with the Determination
 - in the case of forecast financial information relating to the next period, that information has been compiled in all material respects in accordance with the Determination and records kept by Orion
 - in the case of quantitative information provided in spreadsheets, that information is accurately presented. We are working with the OAG on what this means for our assurance review. 'Accurately presented' does not fit with the concept of materiality and clarification is required.
- to report on matters relevant to Orion's systems and processes underlying the CPP proposal which come to our attention and are relevant to management and the board.

Our assurance review involves performing procedures that examine, on a test basis, evidence supporting assumptions, amounts and other information in the CPP proposal, determining compliance with the Determination, and evaluating the overall adequacy of the presentation of information.

We also review other information associated with the CPP proposal to identify whether these are consistent with underlying information.

Reports arising from the assurance review of the Determination

Consistent with the objectives above, the reports arising from the assurance review of the Determination are:

- the assurance report included in the CPP proposal; and
- a management report provided to Orion.

The auditor's assurance report on the CPP proposal

In accordance with clause 5.1.4 of the Determination, the assurance report arising from the assurance review of the Determination will cover the specific matters:

- the work done by the Auditor
- the scope and limitations of the audit
- the existence of any relationship (other than that of auditor) which the Auditor has with, or any interests which the Auditor has in, Orion
- whether the Auditor obtained all information and explanations required to undertake the audit, and if not:
 - details of the information and explanations not obtained, and
 - any reasons provided by Orion for its or their non-provision
- our opinion of the matters in respect of which the audit was undertaken.

The assurance report does not provide a guarantee of absolute accuracy in the CPP proposal.

Provision of a management report to Orion

Consistent with our objectives, we will report to Orion at the conclusion of the engagement. The report communicates matters which come to our attention during the engagement and, which, in our opinion, are relevant. For example, we will report:

- any areas of non compliance noted
- any weaknesses identified in our assurance review, and
- any uncorrected misstatements noted during the assurance review.

Materiality

We have considered materiality in the context of the CPP proposal. Given the nature of special purpose reporting conducted specifically for the Commerce Commission, any misstatements noted will be drawn to Orion's attention for correction. Any misstatements that are not corrected may be referred to in the assurance report. Our preference is for any misstatement to be corrected, avoiding the need to refer to misstatements in our assurance report.

Responsibilities

General responsibilities

The general responsibilities of Orion, with regards to the preparation and completion of the CPP proposal, are consistent with those existing for the annual report as set out in the audit engagement letter – with appropriate allowance for recognising that the CPP proposal deals with forecast information.

Specific responsibilities

Orion is responsible for preparing the CPP proposal under the Determination. We assume that Orion is familiar with those responsibilities and note that Orion has obtained advice about them.

Reporting deadlines

Orion is required to submit the CPP proposal by no later than 22 February 2013. We will need to work together to ensure completion of all the requirements within the timeframes set.

We envisage that the assurance review work for the Determination will be conducted in accordance with the timeframes outlined in section 6.2.

Appendix 2: Applicable charge-out rates

The below table outlines the applicable charge-out rates for the audit team that we will use when auditing the CPP proposal. Our charge-out rates are set to recover only our costs, as we do not budget to make a surplus.

Audit role	Per hour charge-out rate
Audit Director (incorporating EQCR, Tax and ISAA)	██████
Audit Manager	██████
Auditor	██████
AA3	██████
AA2	██████

AUDIT NEW ZEALAND

Mana Arotake Aotearoa



OR037794

V01560

Phone 04 496 3099
Fax 04 496 3095

28. November 2012

Brendan Kearney GM Corp Services
Orion New Zealand Ltd
P O Box 13896
CHRISTCHURCH, 8141
New Zealand

Tax Invoice **SINV08541**
G.S.T. No. 14-290-338

Memorandum of Professional Fees

Interim invoice for the audit of the Customised Price Path	50,000.00
<i>J200163 / R909310</i>	
Net Total	50,000.00
	G.S.T. 7,500.00
Payment is due 7 Days	Total \$ 57,500.00

AUDIT NEW ZEALAND

Mana Arotake Aotearoa

Remittance Advice: Please detach and return with your cheque.

P O Box 3928
Wellington
Phone 04 496 3099
Fax 04 496 3095
E-mail: WIPMANAGEMENT@auditnz.govt.nz
No receipt will be issued unless requested.

Client Name
Client ID
Bill-to Client Name
Bill-to Client ID
Engagement No.
Invoice #
Amount
Direct Credit Details

Orion New Zealand Ltd
C430
Orion New Zealand Ltd
C430
S2C
SINV08541
57,500.00
03-0049 0000407-00

AUDIT NEW ZEALAND

Mana Arotake Aotearoa



OR038740

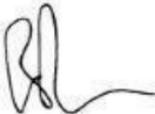
Phone 04 496 3099
Fax 04 496 3095

31. December 2012

Brendan Kearney GM Corp Services
Orion New Zealand Ltd
P O Box 13896
CHRISTCHURCH . 8141
New Zealand

Tax Invoice **SINV08752**
G.S.T. No. 14-290-338

Memorandum of Professional Fees

Interim invoice for the audit of the Customised Price Path	80,000.00
  J200163 R90 9310 / EXT	
Net Total	80,000.00
	G.S.T. 12,000.00
Payment is due 7 Days	Total \$ 92,000.00

AUDIT NEW ZEALAND

Mana Arotake Aotearoa

Remittance Advice: Please detach and return with your cheque.

P O Box 3928
Wellington
Phone 04 496 3099
Fax 04 496 3095
E-mail: WIPMANAGEMENT@auditnz.govt.nz
No receipt will be issued unless requested.

Client Name
Client ID
Bill-to Client Name
Bill-to Client ID
Engagement No.
Invoice #
Amount
Direct Credit Details

Orion New Zealand Ltd
C430
Orion New Zealand Ltd
C430
S2C
SINV08752
92,000.00
03-0049 0000407-00

Appendix 19

Recoverable costs - engineer

1. Richard Gibbons Engineer RFP
2. LineTech Consulting Offer
3. Letter of acceptance
4. Engineer invoice to 11 November 2012
5. Engineer final invoice, 21 January 2013

Direct dial: 03 363 9848
Email: David.Freeman-Greene@oriongroup.co.nz

by email

10 September 2004

Richard Gibbons
General Manager
LineTech Consulting Limited
14 Tui Crescent
Waiatarua
Waitakere City, Auckland 0604

Dear Richard

Request for proposal relating to engineering services

Introduction

- 1 Orion New Zealand Limited (Orion) wishes to engage an independent engineer to assist with a “customised price-quality path” (CPP) application to be submitted to the Commerce Commission (Commission). This letter invites you to submit a proposal to act as that engineer.

Background

- 2 Orion owns and operates the electricity distribution network in central Canterbury between the Waimakariri and Rakaia rivers, and from the Canterbury coast to Arthur's Pass. Orion also owns the electrical contracting business Connectics.
- 3 Orion is a New Zealand electricity distribution services company. Under Part 4 of the Commerce Act 1986 (Act)¹, the Commission may impose regulation of the price and/or quality of goods or services supplied in markets where there is little or no competition or likelihood of a substantial increase in competition. The Commission produces input methodologies in respect of such markets, which set out rules, requirements and processes applying to the regulation of those services.
- 4 The Commission has made a final determination as to the input methodologies applicable to electricity distribution services - the Commerce Act (Electricity

1

http://www.legislation.co.nz/act/public/1986/0005/latest/DLM87623.html?search=ta_act_C_ac%40acur%40anf_an%40bn%40m_25_a&p=4



Distribution Services Input Methodologies) Determination 2010 (Determination). The Determination sets out methodologies which must be applied by the Commission in order to regulate the price and quality of electricity distribution services Orion provides. A copy of the Determination (and the related "Reasons Paper") can be found here: <http://www.comcom.govt.nz/electricity-distribution/>.

- 5 Under section 53Q of the Act, a supplier of electricity distribution services such as Orion may make a proposal to the Commission for a CPP which effectively permits the supplier to follow a different price-quality path from the default price-quality path that would otherwise apply. A CPP proposal must be made in accordance with the methodologies and processes set out in the Determination.
- 6 Following the significant damage to its infrastructure caused by the series of earthquakes affecting the Christchurch area that started on 4 September 2010, Orion proposes to submit a CPP application to the Commission under the catastrophic event provisions of the Determination.
- 7 For the purposes of that application, the Determination requires Orion to engage an independent engineer, to provide reports on certain aspects of that application. The reports are to be included in the CPP application to the Commerce Commission. In particular, we will require reports on:
 - 7.1 a quality standard variation from the default standards set by the Commission must include an engineer's report in accordance with clause 5.4.5(c) of the Determination; and
 - 7.2 an alternative depreciation method in accordance with 5.3.8 must be independently reviewed. Clause G9 of the Determination requires an independent verifier to provide an opinion as to whether the proposed asset life and proposed alternative depreciation method in the CPP application better meets the purposes of Part 4 of the Act than if the standard depreciation method set by the Commission was applied. Orion requires an engineer to provide a report on the substance of clause G9, to be included in Orion's CPP proposal, and to assist the independent verifier fulfil its obligations under clause G9
- 8 Orion has not yet completed preparation of its draft CPP proposal. We anticipate having the quality standard variation and any alternative depreciation method completed to a stage suitable for review by 30 September 2012. We would require the draft engineering reports outlined in paragraphs 7.1, 7.2 above to be completed by Friday 19 October 2012 with final reports due by 30 October 2012. The timeframe for engineering services is accordingly short.
- 9 Orion may require the engineer to be available following submission of the CPP proposal, to answer any questions the Commission may have.

Request for proposal

- 10 You have indicated that you are interested in being appointed as the independent engineer for Orion's CPP proposal. Orion accordingly now requests, on and subject to the terms of this letter, that you submit to it your proposal to act in that role.
- 11 Your proposal should address at least the following matters:
 - 11.1 Your name and contact details.
 - 11.2 Confirmation of your willingness to act as the engineer.
 - 11.3 Confirmation that you have read and understood, and agree to, the terms and conditions of this letter.
 - 11.4 Reasons why you are sufficiently qualified and experienced to carry out the role of the engineer in accordance with the Determination, and an explanation of the nature and extent of your qualifications and experience (and those of your relevant personnel) relevant to carrying out that role.
 - 11.5 Confirmation of your (and your relevant personnel's) availability to act as the engineer and ability to meet the tight timing requirements noted above.
 - 11.6 Confirmation that key personnel will not change without the approval of Orion, such approval not to be unreasonably withheld.
 - 11.7 Any potential impediments to you completing the engineering services within the required timeframe.
 - 11.8 Your terms of engagement which should include the fee basis upon which you would propose to charge for this work, including:
 - (a) an estimate of the probable total fee (if expressed as a range then with no greater variance between the upper and lower bounds than 25% of the lower bound); and
 - (b) the key assumptions on which that estimate is based, including but not limited to:
 - (i) schedule of hourly rates for individuals proposed;
 - (ii) other fees/charges; and
 - (iii) estimates of the time inputs for key tasks.
 - 11.9 How you would expect to carry out your role, addressing in particular

the assessment techniques that you expect to use when undertaking analysis and reviews of information and considering the matters required by clauses 5.4.5(c), and G9 of the Determination.

- 12 Your proposal should be:
 - 12.1 signed by you (or by your duly authorised agent) and include appropriate contact details, including postal and email addresses and telephone numbers;
 - 12.2 delivered prior to 5pm on Tuesday 11 September 2012 (the *Closing Date*) by email (with subject line "*Engineer Proposal*") to: David.Freeman-Greene@Oriongroup.co.nz.
- 13 Submission of your proposal will constitute your agreement to the terms of this letter. Please ensure you have read and familiarised yourself with these provisions.

Acceptance of proposal

- 14 If Orion accepts your proposal, it will give you notice of such acceptance in writing signed by an authorised signatory of Orion. Orion will enclose with that notice the terms of engagement (or such amended terms of engagement as may have been agreed between you and Orion subsequent to receipt by Orion of your proposal) duly executed by Orion. You will immediately execute those terms and return them to Orion.
- 15 If your proposal is unsuccessful, Orion will notify you of that fact.

Yours faithfully



David Freeman-Greene
General Manager Commercial



LineTech Consulting Administration Office
23B Mandeville Street,
PO. Box 8373, Riccarton, Christchurch 8440
Fax (03) 377 2874
Ph (03) 377 1546

Mail from: Richard Gibbons

General Manager
14 Tui Crescent
Waiatarua
Waitakere City
Auckland 0604

Email: richard.gibbons@linetech.co.nz

To: David Freeman-Greene
General Manager Commercial
Orion New Zealand Ltd

By E-Mail

Dear David:

Independent engineer to assist with a “customised price-quality path” (CPP) application

Thank you for the opportunity to put forward a proposal to assist Orion with their application for a customised price path to reflect the effects of the recent earthquakes on the Orion network

We understand that for the purposes of that application, the Determination requires Orion to engage an independent engineer, to provide reports on certain aspects of that application. These reports are to be included in the CPP application to the Commerce Commission. In particular, reports are required on:

- a) a quality standard variation from the default standards set by the Commission must include an engineer’s report in accordance with clause 5.4.5(c) of the Determination; and
- b) an alternative depreciation method in accordance with 5.3.8 must be independently reviewed. Clause G9 of the Determination requires an independent verifier to provide an opinion as to whether the proposed asset life and proposed alternative depreciation method in the CPP application better meets the purposes of Part 4 of the Act than if the standard depreciation method set by the Commission was applied. Orion requires an engineer to provide a report on the substance of clause G9, to be included in Orion’s CPP proposal, and to assist the independent verifier fulfil its obligations under clause G9

LineTech Consulting Ltd puts forward the following proposal for your consideration:-

1. Proposed Independent Engineer:

Ir G. Richard Gibbons
BSc. (Hons), Dip BA, Cert Co Dir; FIET, C.Eng (UK); FIPENZ, CPEng (NZ); Int PE; Life M.EEA; FNZIM ; Ac.MInstD

2. Confirmation of willingness to act as the engineer.

I confirm I am willing to act as the independent Engineer

3. Confirmation that I have read and understood, and agree to, the terms and conditions of this letter

I confirm that I have read and understood, and agree to, the terms and conditions of this letter.

I note that the commercial terms of agreement are to be agreed. Linetech has a current Consultancy Services Agreement with Orion which would be fully acceptable; alternatively we would propose the use of an IPENZ short form agreement

4. Qualifications and experience

I attach my current CV providing details of my qualifications and experience which totals over 40 years in the electrical supply industry.

In relation to this work I would specifically identify the following: -

- I have been involved in the specific topics of quality, including security of supply issues and customer expectations since 1985 when I carried out the first studies in NZ on customer expectations of network performance and price sensitivities as reported in the EEA paper "Keeping the Customer Satisfied - Consumer Based Engineering Standards".
- This work developed further and was reported in the EEA paper "What Price Security" in 1990 which won the Best Paper Award that year. This led through to a significant involvement with the CAE study which resulted in the publication of their book "Reliability of Electricity Supply" in 1993 for which I was a Section Author.
- Following experience gained during the Auckland CBD crisis in 1998 I was involved in various studies and presentations in NZ and overseas on the issues of security of supply and failure modes.
- I was co-author of the current EEA publication "Guidelines for Security of Supply in New Zealand Electricity Networks" in 2000 and I am currently Consultant to the EEA carrying out a review and update of this publication.
- I have previously reviewed aspects of Orion's approach to network security and overall design as well as providing an independent review of Orion's exposure to a major Grid Exit Point failure following the "D Clamp" failure that resulted in a major outage to the Auckland Region.
- More recently I provided services to Aurora Ltd (Delta Utility Services), for their review of their quality and security standards. Other networks have included WEL, United and Aurora (Tasmania).

5. Confirmation of availability to act as the engineer and ability to meet the tight timing requirements

I confirm that I am available to act as the engineer and to meet the proposed timetable.

6. Confirmation that key personnel will not change without the approval of Orion, such approval not to be unreasonably withheld

I confirm that the key personnel will not change without Orion's approval.

7. Potential impediments to you completing the engineering services within the required timeframe

I do not know of any potential impediments to completing the engineering services within the potential timeframe, noting that at the time of making this offer no material has been viewed.

8. Terms of engagement

Without being able to view any material at this time it is very difficult to provide an estimate of the costs involved in the work requested. The following is therefore proposed: -

- The work is to be carried out on a time and disbursements basis. My hourly rate is \$250 plus GST; this is capped at 8 hrs per day.
- A nominal total time of two weeks (i.e. 10 day's work) be allocated for the work, but with reviews to take place after the initial two days and when one week (5 days) has been expended.
- The study will take place at my Auckland office and I would expect question should be able to be answered by phone/e-mail/Skype. I would suggest that it would be desirable to allow for one return flight to Christchurch for a final presentation/review of material. I do not envisage any other significant disbursements as being required. LineTech would recover disbursements at cost plus 10%, alternatively Orion may wish to book travel themselves.
- At this stage it is not expected that other staff will be used, if after receipt of the material, this appears necessary or desirable, then rates and times would be discussed before any action was taken.
- Should further work be necessary, e.g. to answer questions from the Commission, then this time would be chargeable at the above hourly rate for the time taken. No expenditure would be committed under this area without prior approval from Orion.

9. Methodology

Clause 5.4.5 states: -

- (c) an engineer's report on the extent to which the quality standard variation better reflects the realistically achievable performance of the EDB over the CPP regulatory period based on either or both of-
- (i) statistical analysis of past SAIDI and SAIFI performance; and
 - (ii) the level of investment provided for in proposed maximum allowable revenue before tax; and
- (d) 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

The first step will be to understand the approach being taken by Orion in their proposals in relation to sub clauses i) or ii). Once this is established then the proposals and planned outcomes can be compared against reviewed against the default case particularly in relation to what can be realistically achieved. (I would note there must be an issue around the actual timing of the major city rebuilding projects which will impact on when and how Orion will be able/required to provide reticulation and that this would reflect on performance).

Clause 5.3.8 covers "Depreciation - alternative method"

In applying to adopt this option Orion must show that under Clause G9 whether the proposed asset life and proposed alternative depreciation method in the CPP application better meets the purposes of Part 4 of the Act than if the standard depreciation method set by the Commission was applied.

The first step for this aspect of the required report will be to review and understand the approaches taken by Orion to the asset life being allocated to the various components of the network and the impact that has been assessed on asset life by the earthquakes. There may also be an issue relating to the appropriate asset lives that should be allocated to new plant if capital expenditure restrictions are such that plant with shorter expected lives than traditional lives would be installed.

In each case I would expect that an initial review would be undertaken of the material followed by a discussion (phone/Skype) to clarify initial queries or understandings. The next step would be to carry out any specific investigations required to clarify or refine any issues or to establish any useful standards or similar used elsewhere.

This would be followed by the preparation of a report outline/index to allow for agreement on content before a draft report was written and forwarded for your review. Depending on the issues, etc, at that stage a face to face meeting/presentation may be desirable. Once issues are resolved the final report will be provided.

I would expect to review the approach as part of the proposed check points at 2 and 5 days of work.

10. Other Matters

I note that the primary reviews of Orion's application are to be reviewed by Geoff Brown and Associates. I would confirm that I have previously worked with Geoff on other projects and would be pleased to do so, on this project.

Should there be any aspect of this proposal that you wish to discuss please contact me, office 09 814 9642, cell 027 22 88 160, Skype "irrgibbons".

Yours faithfully



Ir. G. Richard Gibbons
General Manager LineTech Consulting Ltd.

Direct dial: 03 363 9848
Email: David.Freeman-Greene@oriongroup.co.nz

by email

14 September 2012

Richard Gibbons
General Manager
LineTech Consulting Limited
14 Tui Crescent
Waiatarua
Waitakere City, Auckland 0604

Dear Richard

Acceptance of proposal relating to independent engineering services

Orion New Zealand Limited (*Orion*) is pleased to advise acceptance of your proposal of 11 September 2012 to provide independent engineering services in relation to our CPP application.

We would also like to advise that the current Consultancy Services Agreement that LineTech has with Orion is acceptable to us.

As discussed in our RFP we anticipate having a draft of our quality standard variation completed to a stage suitable for review by 30 September 2012.

Yours faithfully



David Freeman-Greene
General Manager Commercial





OR037424

V10535

23b Mandeville Street,
PO Box 8373,
Riccarton,
Christchurch 8440
Ph (03) 377 1546
Fax (03) 377 2874
Email: office@linetech.co.nz

TAX INVOICE No: L1211031

Orion NZ Ltd
P O Box 13 896
CHRISTCHURCH

GST Number 89-934-931

Date	Customer	Order Number	Our Ref	Job Number	Sales Ref	Page
11/19/2012	ORION	Dennis Jones		LRG11024	RG	1

Description	Quantity	Unit	Price	Amount
Attn: Dennis Jones				

Independent Review Engineer

Preparation of Report – Independent Engineers Review of Chapter 6.
Receive Instructions & material for review.
Review all documents and supporting data.
Provide initial feedback and questions.
Prepare Draft Report for discussion.
Develop draft to final version.

Principal Consultant - Richard Gibbons
Senior Consultant - John Marsden

\$12,125.00
\$226.50

Reliability Report from independent engineer

26-11-12

5200164 - R909310

Bank A/c: 030823 0986800 00
Paymt due 20th mth following invoice

Total Net	\$12,350.00
GST	\$1,852.50
Invoice Total Including GST	\$14,202.50



23b Mandeville Street,
 PO Box 8373,
 Riccarton,
 Christchurch 8440
 Ph (03) 377 1546
 Fax (03) 377 2874
 Email: office@linetech.co.nz

TAX INVOICE No: L1301049

Orion NZ Ltd
 P O Box 13 896
 CHRISTCHURCH

GST Number 89-934-931

Date 1/21/2013	Customer ORION	Order Number Dennis Jones	Our Ref	Job Number LRG11024	Sales Ref RG	Page 1
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Description	Quantity	Unit	Price	Amount
Attn: Dennis Jones				

Independent Review Engineer

Completion of work as Independent Engineer, including provision of report on specified Asset lives.

Principal Consultant - Richard Gibbons			\$2,875.00
--	--	--	------------

Approved
21-1-13

Bank A/c 030823 0986800 00	Total Net	\$2,875.00
Paymt due 20th mth followng invoice	GST	\$431.25
	Invoice Total Including GST	\$3,306.25

Appendix 20

Project and programme schedule summary

Capex by project (\$000 Nominal)			Current Period			Assessment Period		CPP Period					
Project name	CPP reference	Capex category	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	Total (CPP period)
Urban Major North	CPP1	Major Projects	-	-	-	2,899	12,133	25,656	14,236	-	11,091	-	50,984
Urban Major Dallington	CPP2	Major Projects	-	-	0	9,984	10,240	-	-	-	-	-	-
Urban Major West	CPP3	Major Projects	-	-	-	-	-	106	110	7,156	-	-	7,372
Major Urban Southeast	CPP4	Major Projects	-	-	-	-	-	532	6,320	3,277	-	-	10,129
Major Urban South	CPP5	Major Projects	-	-	-	-	258	-	-	-	-	-	-
Urban Major CBD	CPP6	Major Projects	-	-	-	-	-	532	-	-	-	-	532
Rural Major Rolleston	CPP7	Major Projects	397	11	-	508	7,782	3,872	-	1,947	858	-	6,677
Rural Major Hororata/Creyke 66kV	CPP8	Major Projects	-	-	-	-	-	1,623	-	285	4,221	918	7,047
Major Rural Central Plains	CPP9	Major Projects	-	-	-	-	1,386	-	-	-	4,608	-	4,608
Rural Major Springston	CPP10	Major Projects	-	-	-	100	-	1,321	-	-	-	-	1,321
Rural Major Norwood	CPP11	Major Projects	-	-	-	-	-	-	-	-	294	7,270	7,564
Rural Major Power Factor	CPP12	Major Projects	-	-	-	-	128	136	145	152	159	166	757
Rural Major Annat	CPP13	Major Projects	-	-	-	-	-	-	-	-	538	-	538
Rural Banks Peninsula	CPP14	Major Projects	-	-	-	-	405	874	-	-	-	-	874
Rural Major Southbridge	CPP15	Major Projects	-	-	-	-	-	-	-	114	5,192	-	5,306
Rural Major Dunsandel	CPP16	Major Projects	-	-	-	-	-	-	-	2,694	-	-	2,694
Rural Major Porter Heights	CPP17	Major Projects	-	-	-	-	-	4,790	-	-	-	-	4,790
Rural Major Kimberley	CPP18	Major Projects	-	-	-	-	2,779	-	-	-	-	-	-
Rural Major Alpine	CPP19	Major Projects	-	-	-	-	-	-	257	-	-	-	257
Major Rural GFN	CPP20	Major Projects	-	-	-	856	1,219	-	-	-	-	-	-
Load management software	Current Period	Major Projects	603	-	-	-	-	-	-	-	-	-	-
Urban & rural major projects - 66kV	Current Period	Major Projects	1,721	1,355	3,272	-	-	-	-	-	-	-	-
Urban major projects - Earthquake emergency	Current Period	Major Projects	-	855	774	-	-	-	-	-	-	-	-
Urban major projects - Hornby	Current Period	Major Projects	208	-	-	-	-	-	-	-	-	-	-
Urban major projects - Bromley	Current Period	Major Projects	-	-	222	-	-	-	-	-	-	-	-
Rural major projects - Weedons	Current Period	Major Projects	-	-	8	-	-	-	-	-	-	-	-
Urban & rural major projects - Substations	Current Period	Major Projects	5,190	5,634	16,946	-	-	-	-	-	-	-	-
Urban major projects - QEII	Current Period	Major Projects	-	-	14	-	-	-	-	-	-	-	-
		Subtotal	8,119	7,855	21,236	14,346	36,329	39,442	21,068	15,623	26,961	8,354	111,449
Other Projects													
Underground conversions	CPP50	Underground Conversions	2,588	2,475	3,627	2,300	6,570	1,768	6,862	4,460	1,758	1,096	15,945
Urban reinforcement	CPP51	Reinforcement	3,996	4,949	2,466	1,673	4,249	4,563	2,954	3,973	4,225	3,316	19,031
Rural reinforcement	CPP52	Reinforcement	1,308	369	2,014	2,477	690	785	2,771	2,161	2,085	3,228	11,031
Connections and extensions	CPP53	Customer Connection/Network Extension	5,113	6,058	6,898	9,650	12,829	14,523	15,616	14,612	13,100	12,703	70,554
Spur asset acquisitions	CPP54	Asset Acquisitions	-	-	-	4,188	2,700	16,784	9,419	1,198	-	-	27,401
		Subtotal	13,004	13,851	15,004	20,288	27,038	38,423	37,623	26,405	21,167	20,344	143,963

Replacement													
Overhead lines subtransmission	CPP30	Replacement	231	250	428	340	380	413	2,732	484	497	509	4,635
Overhead lines 11kV and 400V	CPP31	Replacement	3,721	2,427	2,423	2,625	2,973	3,200	3,504	3,706	3,796	3,894	18,100
Underground cables 11kV and 400V	CPP32	Replacement	38	156	123	2,000	2,237	2,428	2,678	2,847	2,924	2,996	13,874
Pilots and protection	CPP33	Replacement	1,034	1,586	2,187	2,640	2,480	2,494	3,136	3,307	3,257	3,563	15,757
Control systems	CPP34	Replacement	-	-	-	1,765	1,672	1,602	1,653	1,535	1,484	1,854	8,128
Load management systems	CPP35	Replacement	-	7	181	790	517	138	1,593	1,020	1,014	515	4,280
Switchgear	CPP36	Replacement	6,084	5,043	3,155	9,239	9,672	9,882	9,723	11,880	9,504	11,066	52,055
Transformers	CPP37	Replacement	459	739	722	1,445	2,437	2,272	2,330	2,348	2,067	2,152	11,169
Substations	CPP38	Replacement	545	108	605	685	520	447	458	462	460	479	2,306
Buildings and grounds	CPP39	Replacement	475	186	55	700	749	1,338	829	862	896	2,560	6,484
Meters	CPP40	Replacement	-	-	11	160	137	138	194	87	86	146	650
Underground cables subtransmission	CPP41	Replacement	547	201	511	50	-	-	-	-	-	-	-
Asset management systems	CPP42	Replacement	-	-	-	239	310	1,087	166	1,026	1,200	183	3,661
Distribution management system	CPP43	Replacement	1,228	762	778	225	823	994	743	662	874	683	3,956
		Subtotal	14,361	11,465	11,181	22,903	24,907	26,433	29,739	30,225	28,058	30,600	145,055
Non-system fixed assets													
Head office building	CPP60	Non System Fixed Assets	-	-	-	14,900	4,637	-	-	-	-	-	-
Sundry land and building	CPP62	Non System Fixed Assets	119	35	1,032	560	258	266	276	285	294	303	1,424
Vehicles and mobile plant	CPP63	Non System Fixed Assets	278	270	855	1,092	867	269	798	894	1,175	734	3,870
Information and technology	CPP64	Non System Fixed Assets	3,507	1,681	2,953	2,958	1,629	1,219	2,062	768	1,488	887	6,424
Sundry tools, equipment, furniture and fittings	CPP65	Non System Fixed Assets	230	926	1,040	520	587	655	635	655	676	697	3,317
		Subtotal	4,134	2,912	5,880	20,030	7,977	2,409	3,771	2,601	3,633	2,621	15,035
Total capex			39,618	36,083	53,301	77,567	96,252	106,708	92,200	74,854	79,820	61,920	415,502

Opex by project (\$000 Nominal)			Current Period					Assessment Period		CPP Period					
Project name	CPP reference	Opex category	FY08	FY09	FY10	FY11	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	Total (CPP period)
Network Opex															
Overhead lines	CPP117	Emergency Maintenance	1,422	1,327	1,340	2,225	2,718	1,475	2,123	2,257	2,876	2,509	2,623	2,741	13,006
Underground cables	CPP118	Emergency Maintenance	1,274	960	1,261	6,141	14,588	2,340	3,365	3,577	4,574	3,978	4,157	4,345	20,630
Network assets	CPP119	Emergency Maintenance	913	835	895	6,168	3,297	1,110	1,414	1,478	1,747	1,605	1,664	1,724	8,218
		Subtotal	3,608	3,122	3,495	14,534	20,603	4,925	6,903	7,311	9,197	8,092	8,443	8,810	41,854
Overhead lines subtransmission	CPP100	Scheduled Maintenance	295	163	381	126	249	920	1,014	1,061	1,177	1,230	1,285	1,343	6,095
Overhead lines 11kV and 400V	CPP101	Scheduled Maintenance	3,268	3,684	4,429	3,123	3,201	4,545	5,759	6,059	6,448	5,590	5,842	6,161	30,099
Earths	CPP102	Scheduled Maintenance	256	126	190	113	145	270	287	305	324	339	354	370	1,692
Underground cables subtransmission	CPP103	Scheduled Maintenance	2,264	2,745	1,954	1,020	27	825	982	1,044	1,111	1,161	1,213	1,268	5,796
Underground cables 11kV and 400V	CPP104	Scheduled Maintenance	484	589	857	637	416	1,430	1,306	1,388	1,477	1,543	1,613	1,686	7,707
Mapping and asset storage	CPP105	Scheduled Maintenance	335	316	300	335	299	508	519	532	547	561	575	589	2,804
Control systems	CPP106	Scheduled Maintenance	-	-	-	-	-	665	705	754	797	829	863	898	4,141
Protection and pilots	CPP107	Scheduled Maintenance	201	330	261	154	102	610	653	705	750	784	806	843	3,889
Transformers	CPP108	Scheduled Maintenance	872	938	1,148	957	1,141	1,165	1,157	1,219	1,297	1,355	1,416	1,480	6,767
Buildings, grounds and substations	CPP109	Scheduled Maintenance	1,345	1,697	1,959	1,641	1,088	3,350	3,434	3,436	3,152	3,294	3,049	3,187	16,117
Meters	CPP110	Scheduled Maintenance	0	4	21	27	73	155	165	175	186	194	203	212	971
Generators	CPP111	Scheduled Maintenance	5	7	-	-	323	100	234	248	528	201	210	233	1,420
Switchgear	CPP112	Scheduled Maintenance	681	787	759	584	486	1,177	1,300	1,314	1,231	1,286	1,344	1,405	6,580
Contingency maintenance	CPP120	Scheduled Maintenance	-	-	-	-	-	-	-	1,570	1,616	1,656	1,697	1,740	8,280
Load management systems	CPP121	Scheduled Maintenance	180	114	152	112	89	355	244	260	276	289	302	315	1,441
Distribution management systems	CPP123	Scheduled Maintenance	258	387	168	216	271	135	249	254	222	307	269	336	1,388
		Subtotal	10,443	11,887	12,577	9,045	7,910	16,210	18,009	20,323	21,138	20,619	21,042	22,065	105,187
Overhead lines	CPP113	Non-scheduled Maintenance	764	946	1,112	933	753	790	839	891	949	991	1,036	1,083	4,950
Network assets	CPP114	Non-scheduled Maintenance	428	509	716	606	490	565	599	637	677	707	739	772	3,533
Underground cables	CPP115	Non-scheduled Maintenance	345	611	375	262	284	290	308	327	348	364	380	397	1,817
Buildings, grounds and substations	CPP116	Non-scheduled Maintenance	351	360	482	693	302	350	372	395	420	439	459	480	2,193
		Subtotal	1,888	2,426	2,684	2,494	1,829	1,995	2,118	2,250	2,394	2,502	2,614	2,732	12,492
Non-Network Opex															
Corporate	CPP160	General Mgmt and Admin	3,008	3,008	3,105	3,119	3,151	3,607	3,660	3,741	3,863	3,967	4,072	4,167	19,809
Finance	CPP161	General Mgmt and Admin	1,000	1,000	987	1,027	955	1,089	1,215	1,243	1,279	1,311	1,343	1,376	6,552
Information solutions - corporate systems	CPP164	General Mgmt and Admin	1,210	1,374	1,590	1,741	1,908	2,634	2,159	2,065	2,116	2,621	2,357	2,416	11,574
Commercial and regulatory	CPP165	General Mgmt and Admin	1,943	2,050	2,310	2,484	1,917	1,461	2,011	2,065	2,163	2,189	2,249	2,310	10,975
Communications and engagement	CPP166	General Mgmt and Admin	-	-	-	-	-	1,094	1,126	1,162	1,204	1,242	1,280	1,320	6,209
Property maintenance	CPP168	General Mgmt and Admin	201	527	606	545	397	1,672	1,433	848	882	913	945	980	4,569
Insurance	CPP169	General Mgmt and Admin	598	635	709	842	1,610	1,972	2,463	2,749	2,966	3,155	3,322	3,498	15,689
Earthquakes - overheads and head office	CPP170	General Mgmt and Admin	-	-	-	1,545	2,164	2,300	124	-	-	-	-	-	-
Special projects	CPP171	General Mgmt and Admin	78	334	177	111	79	2,000	1,546	532	552	569	588	1,516	3,757
		Subtotal	8,038	8,928	9,484	11,414	12,181	17,829	15,736	14,406	15,025	15,965	16,154	17,584	79,134
Infrastructure management	CPP167	Network Mgmt and Ops	8,410	8,712	9,498	10,122	11,795	13,681	15,989	16,916	17,487	17,706	18,166	18,661	88,935
		Subtotal	8,410	8,712	9,498	10,122	11,795	13,681	15,989	16,916	17,487	17,706	18,166	18,661	88,935
Total opex			32,387	35,076	37,738	47,609	54,319	54,640	58,753	61,205	65,242	64,884	66,419	69,852	327,603

Appendix 21

Summary of policies

Summary of relevant policies

IM D3(1) and (2)

9.1 Corporate policies and plans			
Reference	Title	Description/Rationale	Relevance to capex/opex projects and programmes
OR00.10.17	Building Emergency Plan - 200-210 Armagh St	Describes how staff should act if there is an emergency and they are situated in 200-210 Armagh Street	These corporate policies support our entire business operation, and thus are relevant to all projects and programmes. They ensure we operate consistent with good industry practice to achieve efficient, effective and safe outcomes for our staff, consumers, contractors and other stakeholders. However the responsibility for delivering them lies predominantly within our corporate and infrastructure teams. Their activities are included in the following CPP projects:
OR00.00.14	Credit Card - Policy	Prescribes how and when credit cards should be used.	
OR00.00.11	Delegations of Authority - Policy	<p>Sets out what employees are permitted to do as part of the day-to-day running of Orion. This is intended to:</p> <ul style="list-style-type: none"> • Establish clear responsibility, authority, scope and involvement in all operational decision making • Maintain adequate levels of control while empowering employees • Provide managers and employees with appropriate levels of delegation. 	
OR00.00.03	Environmental - Sustainability Policy	This is intended to provide guidance as we work towards our goal of environmental sustainability in our operations.	
OR00.00.08	Fraud and Theft - Policy	Sets out our policy towards fraud and theft. We are committed to the prevention, deterrence, detection and investigation of all fraud and theft.	
OR00.00.06	Hazard Management Plan	The purpose of this management plan is to identify and control hazards that may exist or arise as a result of work undertaken by Orion.	
OR00.00.02	Health and Safety - Committee Constitution	Sets out our policy towards health and safety for all staff. This is intended to help protect our employees, contractors and the public.	
OR00.00.01	Health and Safety - Policy		
OR00.00.18	Housekeeping - Policy	There is a correlation between the state of housekeeping and the number of safety incidents. To enable us to monitor our housekeeping	

performance we have introduced this standard.

OR00.00.05	Human Resources - Policy	This sets out all procedures to be followed for the hiring, management and discipline of employees.
OR00.00.13	Information Systems	This policy provides a general overview of the computing environment and the rules associated with access to it.
OR00.00.07	Major Outage Communication Plan	Outlines staff responsibilities and define the type of communication that will be carried out in the event of a major outage.
OR00.00.22	Media Policy	Sets out the principles which underpin Orion's approach to media relations and the procedures for coordinating and managing media relations.
OR00.00.21	Media Policy - Social	
OR00.00.09	Motor Vehicle - Policy	Ensures that Orion provides and operates motor vehicles to achieve the best possible company outcomes.
OR00.00.12	Orion Sponsorship	Sets out the process for selecting who is eligible to receive sponsorship from Orion.
OR00.00.15	Police Reference Checks - Policy	This sets out our requirement for all prospective employees to undergo a police reference check.
OR00.00.10	Privacy – Policy	Sets out 12 information privacy principles to ensure we comply with the Privacy Act.
OR00.00.19	Procurement (Equipment Purchasing) - Policy	Ensures the following good practice principles are incorporated in all purchasing/procurement decisions made by Orion employees: <ul style="list-style-type: none">• To reflect accountability to the board• To ensure best value for money• To encourage and maintain effective and sustainable competitive markets among our suppliers• To ensure lawfulness, fairness and integrity at all times.
OR00.00.16	Protected Disclosures Policy	To facilitate the disclosure and investigation of matters of "serious wrongdoing" within or by Orion and to protect employees who, in accordance

		with the provisions of the Act, make disclosures of information about “serious wrongdoing” within or by Orion.
OR00.00.04	Staff Travel - Policy	Sets out what restrictions on travel and costs incurred while travelling.
	Code of Conduct for the Board of Directors	Sets out the code of conduct for the board of directors
	Treasury Policy	Outlines the objectives and approach that Orion will adopt in the treasury management process.
	Tax Risk Management Policy	Documents Orion’s approach to the management of tax risk.

9.2.1 Infrastructure management policies and plans			
Reference	Title	Description/Rationale	Relevance to capex/opex projects and programmes
NW70.60.01	Asset Management Plan	To optimise the lifecycle costs for each network asset group to meet agreed service levels and future demand. These policies provide an overall picture of how our assets should be managed and the current condition of the assets.	CPP1 – CPP20 Major Projects CPP51 and CPP52 Reinforcement CPP50 Underground conversions CPP53 Connections and extensions
NW71.01.02	Asset Performance Report		CPP30 – CPP43 Replacement
NW70.00.46	Asset Management Policy		CPP100 – CPP120 Emergency maintenance, scheduled maintenance and non scheduled maintenance CPP60 – CPP65 Non-system fixed assets CPP164 and CPP168 General management, administration and overheads
NW70.60.04	Business Continuity Plan - Infrastructure Management	This identifies our key risks and strategies to manage these for each area of the business.	This plan supports our entire business operation, and thus is relevant to all projects and programmes.
NW70.20.00	Business Plan - Network	The mission of this policy is to: <ul style="list-style-type: none"> Retain and improve network value Cost effectively manage the network asset and improve its performance to a level which meets or exceeds customer service level expectations To manage work on network assets to achieve or exceed expectations of 	CPP1 – CPP20 Major Projects CPP51 and CPP52 Reinforcement CPP50 Underground conversions CPP53 Connections and extensions CPP30 – CPP43 Replacement CPP100 – CPP120 Emergency maintenance, scheduled maintenance and non scheduled maintenance

		contractors and other customer groups.	CPP167 Network management and operations
NW70.00.00	Document Index	Provides a list of all infrastructure management controlled documents.	CPP167 Network management and operations
NW70.00.13	Easements - Agreement to Grant	This is the contract which Orion and the owner of the land on which an easement is being granted sign.	All network capex and maintenance projects which involve easements
NW70.00.08	Environmental - Management Manual	The manuals set out specific responsibilities and procedures to be followed in order to comply with the policies.	These manuals support our entire business operation, and thus are relevant to all projects and programmes.
NW70.00.16	Health and Safety - Management Manual		
NW72.00.00	Over-Boundary Maintenance Policy	Addresses maintenance responsibilities where third party premises are involved	CPP100 – CPP123 Scheduled, non-scheduled and emergency maintenance
NW72.01.01	Overhead Line - Maintenance Costs	Sets out whether expenditure should be considered capex or opex.	CPP30 and CPP31 Replacement CPP100 and CPP101 Scheduled maintenance CPP113 Non-scheduled maintenance CPP117 Emergency maintenance
NW70.00.21	Safety Management System Manual	This manuals set out specific responsibilities and procedures to be followed in order to comply with our safety policies and procedures	These manuals support our entire business operation, and thus are relevant to all projects and programmes.
NW70.00.10	Underground Conversion	Describes how underground conversion costs are apportioned between the parties involved	CPP50 Underground conversions
NW70.01.17	Work Plan - Annual	Sets out the scheduled work plan for the upcoming years. This allows our contractors to better plan their workflow and ensure availability.	All network projects and programmes: CPP1 – CPP20 Major Projects CPP51 and CPP52 Reinforcement CPP50 Underground conversions CPP53 Connections and extensions CPP30 – CPP43 Replacement CPP100 – CPP120 Emergency maintenance, scheduled maintenance and non scheduled maintenance Also relevant to CPP167 Network management and operations which is responsible for co-ordinating and ultimate delivery of the annual works plan

9.2.2 Asset lifecycle management reports

Reference	Title	Description/Rationale	Relevance to capex/opex projects and programmes
NW70.00.33	Circuit Breakers – HV	These reports describe our approach to life cycle maintenance and replacement of each asset category. They include:	CPP36 Replacement CPP112 Scheduled maintenance CPP114 Non scheduled maintenance CPP119 Emergency maintenance
NW70.00.34	Communication Systems	<ul style="list-style-type: none"> a detailed description of the assets installed on our network a description of the condition of those assets and known failures or issues CBRM HI index (where available) lifecycle strategy including planned replacement programme and emergency, scheduled and non scheduled maintenance plans 	CPP34 Replacement CPP106 Scheduled maintenance CPP114 Non scheduled maintenance CPP119 Emergency maintenance
NW70.00.36	Distribution Management Systems	<ul style="list-style-type: none"> lifecycle strategy including planned replacement programme and emergency, scheduled and non scheduled maintenance plans 	CPP34 Replacement CPP106 Scheduled maintenance CPP114 Non scheduled maintenance CPP119 Emergency maintenance
NW70.00.39	Generators	These are updated each year in conjunction with the AMP update and annual works planning	CPP111 Scheduled maintenance CPP114 Non scheduled maintenance CPP119 Emergency maintenance
NW70.00.37	Load Management Systems		CPP35 Replacement CPP121 Scheduled maintenance CPP114 Non scheduled maintenance CPP119 Emergency maintenance
NW70.00.38	Metering		CPP40 Replacement CPP110 Scheduled maintenance CPP114 Non scheduled maintenance CPP119 Emergency maintenance
NW70.00.27	Overhead Lines - 11kV		CPP31 Replacement CPP101 Scheduled maintenance CPP113 Non scheduled maintenance CPP117 Emergency maintenance
NW70.00.25	Overhead Lines – LV		CPP31 Replacement CPP101 Scheduled maintenance CPP113 Non scheduled maintenance CPP117 Emergency maintenance
NW70.00.26	Overhead Lines - Subtransmission		CPP30 Replacement CPP100 Scheduled maintenance CPP113 Non scheduled maintenance CPP117 Emergency maintenance

NW70.00.42	Property – Corporate	CPP60, and CPP62 Non System Fixed Assets CPP168 General management, administration and overheads
NW70.00.43	Property – Network	CPP39 Replacement CPP109 Scheduled maintenance CPP116 Non scheduled maintenance CPP119 Emergency maintenance
NW70.00.44	Property – Substations	CPP38 Replacement CPP109 Scheduled maintenance CPP116 Non scheduled maintenance CPP119 Emergency maintenance
NW70.00.22	Protection Systems	CPP33 Replacement CPP107 Scheduled maintenance CPP114 Non scheduled maintenance CPP119 Emergency maintenance
NW70.00.41	Regulators	CPP36 Replacement CPP112 Scheduled maintenance CPP114 Non scheduled maintenance CPP119 Emergency maintenance
NW70.00.24	Switchgear - HV and LV	CPP36 Replacement CPP112 Scheduled maintenance CPP114 Non scheduled maintenance CPP119 Emergency maintenance
NW70.00.40	Transformers - Distribution	CPP37 Replacement CPP108 Scheduled maintenance CPP114 Non scheduled maintenance CPP119 Emergency maintenance
NW70.00.23	Transformers - Power	CPP37 Replacement CPP108 Scheduled maintenance CPP114 Non scheduled maintenance CPP119 Emergency maintenance
NW70.00.30	Underground Cables - 11kV	CPP32 Replacement CPP104 Scheduled maintenance CPP115 Non scheduled maintenance CPP118 Emergency maintenance

9.2.3 Design standards

Reference	Title	Description/Rationale	Relevance to capex/opex projects and programmes
NW70.52.01	Cables - Underground Cable Design	These set out the minimum requirements and design specifications for assets on our network.	<p>They are relevant to all network capex projects (as part of asset design), to the extent that each project includes the relevant equipment: CPP1 – CPP20 Major Projects CPP51 and CPP52 Reinforcement CPP50 Underground conversions CPP53 Connections and extensions</p> <p>They are also relevant to all network maintenance programmes to ensure assets perform as intended throughout their life CPP30 – CPP43 Replacement CPP100 – CPP120 Emergency maintenance, scheduled maintenance and non scheduled maintenance</p>
NW70.57.03	Design Application Guide - Distribution Feeder and Transformer Protection	The rationale is to ensure that all of our assets are capable of completing the job we require of them. They also help ensure our network performance and customer performance targets are met.	
NW70.50.02	Draughting & Records		
NW70.59.01	Earthing - Design		
NW70.57.06	Ground Fault Neutraliser - Design Application Guide		
NW70.55.01	Metering Design		
NW70.00.12	Network Asset Identification		
NW70.50.05	Network Design Overview		
NW70.51.02	Overhead Line - Design Manual		
NW70.51.01	Overhead Line - Design Standard		
NW70.51.04	Overhead Line - Technical Manual		
NW70.51.03	Overhead Line - Worked Examples		
NW70.57.01	Protection - Design		
NW70.50.06	Railway Crossing Application Form (KiwiRail)		
NW70.56.01	SCADA Functional Specification for Remote Sites		
NW70.53.02	Substation - Customer Premises		

NW70.53.01	Substation - Design		
NW70.57.02	Subtransmission Protection - Design		
NW70.50.03	Document Control	Provides a list of all controlled documents	These controlled documents support our entire business operation, and thus are relevant to all projects and programmes.

9.2.4 Technical specifications

Reference	Title	Description/Rationale	Relevance to capex/opex projects and programmes
Overhead network			
NW72.21.04	ABI maintenance	The technical specifications set out the procedures for the maintenance and replacement for our network assets. This includes the procedures to be followed when testing and working on the assets.	CPP30 and CPP31 Replacement CPP100 and CPP101 Scheduled maintenance CPP113 Non-scheduled maintenance CPP117 Emergency maintenance
NW72.21.23	Excavation Protocols - Near Electrical/Telecommunication Lines		
NW72.31.01	Overhead Line - Construction Checklist	The rationale is to ensure the equipment on our network is operated: <ul style="list-style-type: none"> safely to ensure our health and safety standards are met prudently to ensure our network performance and consumer performance standards and targets are met 	
NW72.21.11	Overhead Line - Inspection & Assessment		
NW72.31.02	Overhead Line - Inspection Sheet		
NW72.21.03	Overhead Line - Retighten Components		
NW72.21.05	Overhead Line - Tower Painting		
NW72.21.09	Overhead Line - Visual Inspection of HV		
NW72.21.01	Overhead Line - Work		
NW72.21.16	Poles - Attachment Engineering Agreement - Between Orion & Telecom		

NW72.21.22	Poles - Ownership Agreement - Between Orion & Telecom		
NW72.21.17	Poles - Shared Use - Attachment Guideline		
NW72.21.14	Poles - Shared Use - Engineering Practice		
NW72.21.15	Poles - Shared Use - Engineering Practice - Telecomm Service Drops (Telstra)		
NW72.21.18	Standard Construction Drawing Set - Overhead		
NW72.21.10	Thermographic Survey of HV Network		
NW72.21.19	Tower Foundation Inspections		
NW72.14.01	Tree Cutting Notification		
NW72.24.01	Vegetation Work Adjacent to Overhead Lines		
NW72.21.13	Vibration Damper Installation		
Underground network			
NW72.22.04	Cables - 66kV Civil Construction - McFaddens to Dallington	The technical specifications set out the procedures for the maintenance and replacement for our network assets. This includes the procedures to be followed when testing and working on the assets.	CPP32, CPP33 and CPP41 Replacement CPP103, CPP104 and CPP107 Scheduled maintenance CPP114 and CPP115 Non-scheduled maintenance CPP118 and CPP119 Emergency maintenance
NW72.22.05	Cables - 66kV Installation - McFaddens to Dallington		
NW72.22.02	Cables - Excavation & Backfilling	The rationale is to ensure the equipment on our network is operated:	
NW72.22.01	Cables - Installation & Maintenance	<ul style="list-style-type: none"> safely to ensure our health and safety standards are met 	
NW71.12.03	Cables - Recording Cables & Associated plant	<ul style="list-style-type: none"> prudently to ensure our network performance 	

NW72.23.24	Cables - Testing	and consumer performance standards and targets are met	
NW72.22.03	Distribution Enclosure Installation		
NW72.12.01	Duct Installation For Future Use		
NW72.21.12	Low Voltage UG Network Inspection		
NW72.21.20	Standard Construction Drawing Set - Underground		
Substations			
NW72.23.18	Building Sub - Install Equipment	The technical specifications set out the procedures for the maintenance and replacement for our network assets. This includes the procedures to be followed when testing and working on the assets.	CPP37, CPP38 and CPP39 Replacement CPP102, CPP108 and CPP109 Scheduled maintenance CPP114 and CPP116 Non-scheduled maintenance CPP119 Emergency maintenance
NW72.23.03	Distribution Sub - Inspection		
NW72.23.05	Distribution Sub - Maintenance		
NW72.23.02	Distribution Transformer - Maintenance	The rationale is to ensure the equipment on our network is operated:	
NW72.28.01	Earthing - Installation	<ul style="list-style-type: none"> • safely to ensure our health and safety standards are met • prudently to ensure our network performance and consumer performance standards and targets are met 	
NW72.28.02	Earthing - Testing		
NW72.23.26	Jointing instruction - Prysmian 72.5kV Outdoor Sealing End		
NW72.23.14	Kiosk Sub - Installation		
NW72.23.01	Mineral Insulating Oil - Maintenance		
NW72.23.04	Network Sub - Inspection		
NW72.23.06	Network Sub - Maintenance		

NW72.23.19	Network Substation - Seismic Strengthening		
NW72.23.15	OCB - Servicing After Fault Operation		
NW72.27.03	Partial Discharge Tests		
NW72.23.20	Pole Mounted Sub - Fuse Maintenance		
NW72.23.25	Power Transformer - Maintenance		
NW72.27.02	Protection		
NW72.23.22	Regulators - Install or Change on O/D Pad Mounted Sites		
NW72.21.21	Standard Construction Drawing Set - Substations		
NW72.27.04	Testing and Commissioning of Secondary Equipment		
NW72.23.16	Transformer - Installation		
NW72.27.01	Unit Protection 11kV - Maintenance Tests		
NW72.23.13	Zone Sub - Inspection		
NW72.23.07	Zone Sub - Maintenance		
Miscellaneous			
NW72.20.06	Fuse Application on the Network	The technical specifications set out the procedures for the maintenance and replacement for our network assets. This includes the procedures to be followed when testing and working on the assets.	CPP30 – CPP43 Replacement CPP100 – CPP120 Emergency maintenance, scheduled maintenance and non scheduled maintenance
NW72.20.07	Grounds Maintenance		CPP168 General management, administration and overheads

		The rationale is to ensure the equipment on our network is operated:	CPP109 Scheduled maintenance CPP116 Non-scheduled maintenance CPP119 Emergency maintenance
NW72.25.07	Metering Installations intended for Energy Trading & compliance with EMCO	<ul style="list-style-type: none"> • safely to ensure our health and safety standards are met • prudently to ensure our network performance and consumer performance standards and targets are met 	CPP40 Replacement CPP110 Scheduled maintenance CPP114 Non-scheduled maintenance CPP119 Emergency maintenance
NW72.25.03	Orion Check Metering with Transpower at POS		CPP40 Replacement CPP110 Scheduled maintenance CPP114 Non-scheduled maintenance CPP119 Emergency maintenance
NW70.26.01	Ripple Control System - Technical Details		CPP35 Replacement CPP114 Non-scheduled maintenance CPP119 Emergency maintenance
NW72.26.02	Ripple Equipment Maintenance		
NW72.26.04	Scada Master Maintenance		CPP34 and CPP43 Replacement CPP106 and CPP123 Scheduled maintenance CPP114 Non-scheduled maintenance CPP119 Emergency maintenance
NW72.26.05	Scada RTU Maintenance		
NW72.25.04	Tariff Meter Individual Testing		CPP40 Replacement CPP110 Scheduled maintenance CPP114 Non-scheduled maintenance CPP119 Emergency maintenance

9.3.1 Network operation plans

Reference	Title	Description/Rationale	Relevance to capex/opex projects and programmes
NW20.40.10	Contingency Plan - AMI Stadium	These set out our plans to mitigate the effects of outages or other events for particular items which have been identified as having a high risk to the public, our staff, our network or our reputation.	CPP167 Network management and operations
NW20.40.09	Contingency Plan - Security of Supply, Participant Outage Plan		
NW20.40.02	Contingency Plan - Emergency Generators		
NW20.40.04	Contingency Plan - Energy Shortage		

NW20.40.01	Contingency Plan - Equipment Failure
NW20.40.07	Contingency Plan - Irrigation Load Shedding
NW20.40.06	Contingency Plan - Loss of Ripple Plant Injection into 66kV
NW20.40.03	Contingency Plan - Loss of Supply
NW20.40.08	Contingency Plan - Relocating the Control Centre
NW20.40.05	Disconnection of Demand as Required by ECom Rules

9.3.2 Operating standards

Reference	Title	Description/Rationale	Relevance to capex/opex projects and programmes
NW21.01.01	Commissioning of HV Equipment that changes Network Configuration	To ensure the equipment on our network is operated safely our operating procedures cover:	CPP167 Network management and operations CPP1 – CPP20 Major Projects CPP51 and CPP52 Reinforcement CPP50 Underground conversions CPP53 Connections and extensions CPP30 – CPP43 Replacement CPP100 – CPP120 Emergency maintenance, scheduled maintenance and non scheduled maintenance
NW21.70.01	Commissioning Orion LV Network	<ul style="list-style-type: none"> • Release of network equipment 	
NW21.72.01	Connect to Orion Street-lighting Network	<ul style="list-style-type: none"> • Commissioning procedures • System restoration 	
NW21.06.03	Entry Approval Certificates	<ul style="list-style-type: none"> • Training • Access control to system assets 	
NW21.02.05	Marking the Boundaries of Work Permit Areas in Stations		
NW21.07.04	Minimum Safe Approach Distances		
NW21.05.02	Operating Log		
NW21.02.01	Operating Order HV-Preparation and Use		
NW21.06.05	Operating Performance Criteria		

NW21.05.03	Operating Terms Dictionary
NW21.03.04	Orion's Mobile Generators
NW21.06.06	Permission to Work
NW21.02.08	Permit for HV Live Line Work
NW21.02.07	Permit for Work on Network Equipment
NW21.06.02	Permit Holder Certificates
NW21.07.03	Personal Protective Equipment
NW21.01.02	Release of Network Equipment
NW21.70.02	Request to Work or Operate LV Network
NW21.03.02	Restoration Following HV Network Fault
NW21.07.02	Station Security
NW21.03.03	Testing Installation Mains
NW21.02.09	Work Authorities
NW21.06.04	Work Authority Competency

9.3.3 Operating procedures

Reference	Title	Description/Rationale	Relevance to capex/opex projects and programmes
NW22.30.04	Authorising Work Between the Consumer NCP and POE	To ensure the equipment on our network is	CPP167 Network management and operations

NW21.30.03	Cat Up a Pole	operated safely our operating procedures cover: <ul style="list-style-type: none"> • Release of network equipment • Commissioning procedures • System restoration • Training • Access control to system assets 	CPP1 – CPP20 Major Projects CPP51 and CPP52 Reinforcement CPP50 Underground conversions CPP53 Connections and extensions CPP30 – CPP43 Replacement CPP100 – CPP120 Emergency maintenance, scheduled maintenance and non scheduled maintenance
NW21.30.02	Certificates of Competence for Access - Guidelines for Issue		
NW20.30.04	Communication in the Event of an Interruption to Supply - Handling		
NW20.30.02	Consumer Complaints - Handling		
NW20.20.04	Demolition of Premises		
NW21.60.01	High Loads - Approval for transport		
NW20.10.01	HV Network Owners		
NW21.32.05	HV Network Site Identification and Temporary Circuit Labelling		
NW00.20.02	Incident/Accident Recording		
NW26.10.01	Incident/Accident Reporting and Investigation Procedures		
NW22.30.03	Isolation/Cover-up of OH Mains for Consumer Painting/Tree Trimming		
NW21.31.02	LV Alteration Sheet		
NW21.31.04	LV Network Site Identification and Circuit Labelling		
NW21.31.05	LV Service Mains - New - Connecting and Livening		
NW21.31.03	LV Ties Between Substations		
NW20.30.03	Patrolling O/H Lines Along Public Roadways		
NW20.30.01	Power - No/Part/Low/Intermittent - Handling		

NW21.31.01	LV Circuits – Pre-commissioning Tests and Livening
NW20.01.03	Voice Recording - Protocol
NW22.30.02	Relocation of O/H Mains to Allow Work on Consumer Barge Boards
NW22.30.01	Relocation of O/H Mains to Allow Work on Consumer Spouting
NW21.19.20	Upper South Island Load Management
NW20.01.02	Use of Digital Cameras
NW20.01.01	Use of Portable Generators During Planned Maintenance
NW27.30.02	Use of Sparks Rd No.383 Training Facility
NW21.30.04	Voltage Deviations - Handling - Commercial/Industrial
NW21.30.05	Voltage Deviations - Residential - Handling

9.3.4 Operating instructions

Reference	Title	Description/Rationale	Relevance to capex/opex projects and programmes
NW72.13.89	11kV ABI CEC HM-L (Motorised)	To ensure the equipment on our network is operated:	CPP167 Network management and operations CPP1 – CPP20 Major Projects
NW72.13.95	11kV ABI EPS1FS - Hot Stick Operated ABI	<ul style="list-style-type: none"> Safely to ensure our health and safety standards are met 	CPP51 and CPP52 Reinforcement CPP50 Underground conversions
NW72.13.92	11kV ABI NASAT Remote Controlled	<ul style="list-style-type: none"> Prudently to ensure our network performance and consumer performance standards and targets are met 	CPP53 Connections and extensions CPP30 – CPP43 Replacement
NW72.13.81	11kV AIU Magnefix MD4		CPP100 – CPP120 Emergency maintenance, scheduled maintenance and non scheduled maintenance
NW72.13.70	11kV Circuit Breaker Holec Xiria		

NW72.13.211	11kV Enermet Ripple Plant
NW72.13.72	11kV Fuse switch Brush HFU
NW72.13.74	11kV Fuse switch F&P IB
NW72.13.79	11kV Fuse switch L&C GF3
NW72.13.86	11kV Fuse switch Statter VAA
NW72.13.87	11kV Fuse switch Statter VL
NW72.13.88	11kV Fuse switch Statter VL/2-OD
NW72.13.56	11kV GCB South Wales HK12SF6
NW72.13.96	11kV Line Fault Indicator LINETROLL 3500
NW72.13.91	11kV Line logger
NW72.13.90	11kV Neutral Earthing Resistor CCEPB
NW72.13.28	11kV OCB Brush VBAD
NW72.13.30	11kV OCB Brush VSI
NW72.13.32	11kV OCB C&F ULB1
NW72.13.33	11kV OCB C-P ALA3
NW72.13.34	11kV OCB F&P BVP3,4 & BVU3,4
NW72.13.23	11kV OCB GEC-AEI BVP17 & BTVP17

NW72.13.51	11kV OCB Reyrolle LA23T
NW72.13.57	11kV OCB South Wales C4X,D4,D4X
NW72.13.62	11kV OCB South Wales D4X,D6X
NW72.13.54	11kV OCB Statter AC01
NW72.13.55	11kV OCB Statter AC2
NW72.13.52	11kV OCB/VCB Reyrolle LMT & LMVP
NW72.13.78	11kV Oil switch L&C J4
NW72.13.83	11kV Oil switch Reyrolle IA23
NW72.13.49	11kV Pole VCB Control Relay Microtrip 2
NW72.13.45	11kV Pole VCB Cooper V4H 1ph
NW72.13.46	11kV Pole VCB McGraw Edison KF
NW72.13.47	11kV Pole VCB McGraw Edison KFE
NW72.13.48	11kV Pole VCB McGraw Edison KFME
NW72.13.41	11kV Pole VCB Nu-Lec Type N12
NW72.13.42	11kV Pole VCB Nu-Lec Type U12
NW72.13.80	11kV Sectionaliser McGraw Edison GN3E
NW72.13.84	11kV Sectionaliser Reyrolle OYS

NW72.13.63	11kV VCB Holec SVS
NW72.13.64	11kV VCB Toshiba VK10J25
NW72.13.66	11kV VCB/SF6 S&C Vista
NW72.13.203	11kV Voltage Regulator ASEA
NW72.13.202	11kV Voltage Regulator EEC
NW72.13.201	11kV Voltage Regulator Ferranti
NW72.13.204	11kV Voltage Regulator Siemens
NW72.13.19	33kV Fuse S&C SMD-20
NW72.13.20	33kV GCB Merlin Gerin (Transpower owned)
NW72.13.12	33kV OCB ASEA HLC & HKCYB
NW72.13.14	33kV OCB GEC OIKW3
NW72.13.16	33kV OCB McGraw Edison RVE
NW72.13.17	33kV OCB Sace RGE36
NW72.13.18	33kV OCB Sprecher
NW72.13.94	33kV VCB Tamco - VH3/VH3D
NW72.13.215	66/11kV Transformer - Pauwels Type ORF 40/140
NW72.13.11	66kV ABI SDCEM SR16200

NW72.13.10	66kV GCB Alstom DT1-72.5 (SF6)
NW72.13.07	66kV OCB ASEA HLC
NW72.13.08	66kV OCB Reyrolle 660SM120
NW72.13.09	66kV OCB Sprecher HGF309
NW72.13.99	Ground Fault Neutraliser
NW72.13.111	Hotstick Line Sniffer
NW72.13.120	Meter - Power Quality GE Multilin
NW72.13.03	OCB - AEI BVP17 Maintenance
NW72.13.02	OCB - South Wales 11kV CX, DX Maintenance
NW72.13.110	Parabolic Pinpointer
NW72.13.112	Phasing Set - Fameca 4000
NW72.13.101	Relay - Feeder Management GE Multilin SR760
NW72.13.102	Relay - Feeder Management SEL 587
NW72.13.103	Relay - Feeder Protection MiCOM P120,122,123
NW72.13.105	Relay - Line Differential GE Multilin L90
NW72.13.106	Relay - Transformer Differential GE Multilin T60
NW72.13.100	Relay - Transformer Management GE Type SR745

NW72.13.107	Relay - Voltage Regulating a-eberle REG-D
NW72.13.210	Standby Generator - Simeon
NW72.13.97	Standby Generator Truck 350kVA
NW72.13.109	Standby Generator Truck 400kVA
NW72.13.98	Standby Generator Truck 440kVA
NW72.13.113	Static Generator Set 2500kVA
NW72.13.01	Transformer (Major) - Vacuum Filling

9.7.1 Risk Management

Reference	Title	Description/Rationale	Relevance to capex/opex projects and programmes
NW70.60.02	Asset Risk Management Plan - Electricity	Identifies significant risks to the Orion network and provides a summary of contingencies to eliminate, prevent or minimise the impact of those risks.	This core plan and the associated documents support our entire business operation, and thus are relevant to all projects and programmes.
NW70.00.17	CDEM Act Summary	Documents which support our asset risk management plan	
NW70.00.18	CDEMS Manual		
NW70.00.19	Risk Management Summary		
NW70.00.14	Disaster Resilience Summary	Provides the Canterbury Civil Defence Emergency Group with a high-level overview of Orion's services and operations to assist them and our stakeholders with their roles in the event of a civil emergency.	
NW70.10.02	Environmental - Management Procedure - Oil and Fuel	Contains the requirement for managing the environmental risk mitigation standards and procedures associated with oil/fuel contained	CPP1 – CPP20 Major Projects CPP51 and CPP52 Reinforcement CPP50 Underground conversions

		within, used for the operation of, or work on our electricity network assets.	CPP53 Connections and extensions CPP30 – CPP43 Replacement CPP100 – CPP120 Emergency maintenance, scheduled maintenance and non scheduled maintenance
NW70.10.01	Environmental - Management Procedure - SF6 Gas	Contains the requirement for managing the environmental risk mitigation standards and procedures associated with SF6 used for the operation of and work on our electricity network assets.	CPP1 – CPP20 Major Projects CPP51 and CPP52 Reinforcement CPP50 Underground conversions CPP53 Connections and extensions CPP30 – CPP43 Replacement CPP100 – CPP120 Emergency maintenance, scheduled maintenance and non scheduled maintenance
NW70.60.03	Physical Security Plan	This security plan details Orion's security policies, principles and procedures relating to the restriction of physical access to our electrical assets and associated infrastructure.	CPP1 – CPP20 Major Projects CPP51 and CPP52 Reinforcement CPP50 Underground conversions CPP53 Connections and extensions CPP30 – CPP43 Replacement CPP100 – CPP120 Emergency maintenance, scheduled maintenance and non scheduled maintenance CPP168 General management, administration and overheads
NW70.10.06	Environmental - Risk Register (Parts A & B)	The aim of this Environmental Risk Register is to provide a summary of all the environmental risks, related to our business and operations. This includes estimates of the likelihood of their occurrence, consequences and ways of mitigating the risk.	This register supports our entire business operation, and thus is relevant to all projects and programmes.

9.4.2 Hazard Identification			
Reference	Title	Description/Rationale	Relevance to capex/opex projects and programmes
OR00.10.02	Hazard Group - Armed Robbery	These documents set out any identified hazards and methods of controlling them. The rationale for these is to ensure the safety of our employees, contractors and the general public on our sites	These policies support our entire business operation, and thus are relevant to all projects and programmes.
OR00.10.03	Hazard Group - Contractors		They ensure we operate safely for our staff, consumers, contractors and other stakeholders. However the

OR00.10.04	Hazard Group - Electricity	and around our assets.	<p>responsibility for delivering them lies predominantly within our corporate and infrastructure teams. Their activities are included in the following CPP projects:</p> <ul style="list-style-type: none"> • CPP160, CPP161, CPP165, CPP166 and CPP171 General management, administration and overheads • CPP167 Network management and operations
OR00.10.05	Hazard Group - Extreme Temperatures		
OR00.10.06	Hazard Group - Forklifts		
OR00.10.07	Hazard Group - Manual Handling		
OR00.10.08	Hazard Group - Office Environments		
OR00.10.09	Hazard Group - Plant and Equipment		
OR00.10.10	Hazard Group - Slips, Trips and Falls		
OR00.10.11	Hazard Group - Stress and Fatigue		
OR00.10.12	Hazard Group - Trenches and Open Excavations		
OR00.10.13	Hazard Group - Underground Services		
OR00.10.14	Hazard Group - Vehicles		
OR00.10.15	Hazard Group - Visitors and Others		
OR00.10.16	Hazard Group - Working on the Road		

9.5.1 Contract Management			
Reference	Title	Description/Rationale	Relevance to capex/opex projects and programmes
NW73.10.11	Construction Audit Process	These set out the minimum requirements for most contracts entered into by Orion. They are intended to ensure:	All network projects and programmes: CPP1 – CPP20 Major Projects CPP51 and CPP52 Reinforcement CPP50 Underground conversions
NW73.10.07	Contract - Administration		

NW73.10.13	Contract - Evaluation of Tenders	<ul style="list-style-type: none"> • We always contract suppliers who are capable of achieving the intended goal • All aspects of the contract are met • The contract covers all areas required • We receive the best possible price for the contracted service 	<p>CPP53 Connections and extensions CPP30 – CPP43 Replacement CPP100 – CPP120 Emergency maintenance, scheduled maintenance and non scheduled maintenance Also relevant to CPP167 Network management and operations which is responsible for contract management and performance</p>
NW72.20.10	Contract - Hazard Management		
NW73.00.03	Contract - Management		
NW72.20.05	Contract - Performance Monitoring		
NW73.10.16	Contract - Post Contract Evaluation		
NW73.00.01	Contract - Standard Document		
NW73.00.02	Contract - Standard Procedure		
NW73.10.09	Contract - Tender Procedures		
NW73.10.14	Contract - Works - Externally Driven		
NW73.10.08	Contract - Works - Internally Driven		
NW73.10.15	Contractors - Authorised and Approved List		
NW72.11.03	Event Reporting		
NW70.00.20	Geomedia WebMap Contractor Website - TUA		
NW72.00.01	Health and Safety Checklist		
NW73.10.10	Pricing Request		
NW72.11.02	Working near the Orion network - Competency		
NW72.20.03	Works - Emergency		

NW73.10.18	Works - Environmental Audit
NW72.20.04	Works - General Requirements
NW73.10.17	Works - Management - Audit Procedure

9.6.1 Connections and Embedded Generation

Reference	Title	Description/Rationale	Relevance to capex/opex projects and programmes
NW72.15.02	Connection and Livening Guide for Low Voltage Electricity Installations	These outline the technical requirements relating to extensions and connections to Orion's electricity network.	CPP53 Connections and extensions
NW70.10.03	Connection to the Network		
NW72.15.05	Distributed Generation - Guide to Connection		
NW70.10.09	Distributed Generation - Information Pack		
NW70.10.04	Embedded Generation - Requirements		
NW72.15.03	Guide to Permanent Disconnection of Premises		
NW72.15.04	Guide to Temporary Connections		
NW72.15.01	Installation and Service Guide for Electricity Connections and Metering		
NW70.00.15	Network Code		
NW70.00.45	Network Connections and Extension Policy		

9.7.1 Procurement and Stock Management

Reference	Title	Description/Rationale	Relevance to capex/opex projects and programmes
NW72.20.08	Network Storage and Supply Services	Stock and spares management policies ensure equipment is available to facilitate efficient emergency response and maintenance programmes. Our stock management policies seek to ensure that sufficient (but not excess) stock for core items is held	Facilitates emergency maintenance programmes (CPP117 – CPP119) and scheduled and non-scheduled maintenance programmes (CPP100- CPP116 and CPP121)
NW72.20.09	Spares - Storage & Maintenance Management Using WASP		
NW72.20.11	Orion Stock Management		
NW72.23.12	Spares - Long Term		

9.7.2 Equipment Specifications

Reference	Title	Description/Rationale	Relevance to capex/opex projects and programmes
NW74.23.04	Cable - Distribution - 11kV	<p>Equipment specifications set out the standard requirements for core equipment used on our network. These include accepted performance criteria for each item of equipment. The rationale for our equipment specifications includes:</p> <ul style="list-style-type: none"> Standardisation which enhances efficiency of network construction and maintenance activities by ensuring only standard equipment is installed and hence maintained Enables many contractors to work on our network with clear instructions regarding the equipment to be used Ensures our safety, performance and environmental standards are met 	<p>CPP51 Reinforcement CPP32 Replacement CPP50 Underground conversions CPP53 Connections and extensions CPP118 Emergency maintenance CPP104 Scheduled maintenance CPP115 Non scheduled maintenance CPP1 – CPP6 Urban Major Projects CPP41 Replacement CPP118 Emergency maintenance CPP103 Scheduled maintenance CPP115 Non scheduled maintenance</p>
NW74.23.11	Cable - Distribution - 400V		
NW74.23.14	Cable - Subtransmission - 33kV		
NW74.23.32	Cable - Subtransmission - 66kV - (Bromley to Dallington/Rawhiti)		
NW74.23.29	Cable - Subtransmission - 66kV - (McFaddens to Dallington)		
NW74.23.27	Cable - Subtransmission - 66kV - (Middleton)		
NW74.23.31	Cable - Subtransmission - 66kV - 1600mm ² Cu XLPE		
NW74.23.30	Cable - Subtransmission - 66kV - 300mm ² Cu XLPE		

NW74.23.19	Cross Arms - Wooden	CPP7, CPP8, CPP17, CPP18 Rural Major Projects CPP52 Reinforcement
NW74.23.10	Insulator - HV Overhead Lines	CPP30 and CPP31 Replacement CPP53 Connections and Extensions
NW74.23.17	Overhead Conductors	CPP117 Emergency maintenance CPP100 and CPP101 scheduled maintenance CPP113 Non scheduled maintenance
NW74.23.08	Pole – Hardwood	
NW74.23.06	Pole – Softwood	
NW74.23.09	Ripple Control System	CPP33 and CPP35 Replacement CPP119 Emergency maintenance
NW74.23.21	Communication System	CPP107 and CPP121 Scheduled maintenance CPP114 Non scheduled maintenance
NW74.23.13	Circuit Breaker - 11kV indoor	CPP1 - CPP6 Urban Major Projects CPP7 – CPP20 Rural Major Projects
NW74.23.28	Circuit Breaker - 33kV indoor	CPP51 and CPP52 Reinforcement CPP36 Replacement
NW74.23.25	Circuit Breaker - 66kV	CPP53 Connections and extensions CPP119 Emergency maintenance CPP112 Scheduled maintenance CPP114 Non scheduled maintenance
NW74.23.20	Earthing Equipment - Approved and Application	
NW74.23.15	Regulator - 11kV	
NW74.23.12	Surge Arrestor - 66kV	
NW74.23.23	Switchgear - 400V - Approved and Application	
NW74.23.26	Current Transformer - 66kV	CPP1 - CPP6 Urban Major Projects CPP7 – CPP20 Rural Major Projects
NW74.23.18	Current Transformer - 66kV - Outdoor	CPP51 and CPP52 Reinforcement CPP37 Replacement
NW74.23.05	Transformer - Ground Mounted Distribution - 200 to 1000kVA	CPP53 Connections and extensions CPP119 Emergency maintenance

NW74.23.22	Transformer - Primary - 33/11kV 2.5MVA	CPP108 Scheduled maintenance CPP114 Non scheduled maintenance
NW74.23.16	Transformer - Primary - 66/11kV 11.5/23MVA	
NW74.23.24	Transformer - Primary - 66/11kV 40MVA	
NW74.23.07	Transformer - Primary - 66/11kV 7.5/10MVA	
NW74.23.01	Kiosk Shell - Full	CPP51 and CPP52 Reinforcement CPP39 Replacement
NW74.23.02	Kiosk Shell - Half	CPP53 Connections and extensions CPP119 Emergency maintenance CPP109 Scheduled maintenance
NW74.23.03	Kiosk Shell - Quarter	CPP116 Non scheduled maintenance

9.7.3 Other network policies			
Reference	Title	Description/Rationale	Relevance to capex/opex projects and programmes
NW70.60.12	Long Term Load Forecasting Methodology for Subtransmission and Zone Substations	Sets out the method and inputs used by Orion when we determine our expected load growth.	CPP1 – CPP20 Major Projects CPP51 and CPP52 Reinforcement
NW70.60.13	Project Budget Forecasting Process	Describes how the project budget is established.	CPP1 – CPP20 Major Projects CPP51 and CPP52 Reinforcement CPP50 Underground conversions CPP53 Connections and extensions
NW70.60.14	Project Prioritisation and Deliverability Process	Describes the primary factors used to prioritise projects. Also details the steps we have taken to ensure all projects are deliverable.	CPP1 – CPP20 Major Projects CPP51 and CPP52 Reinforcement CPP50 Underground conversions CPP53 Connections and extensions CPP30 – CPP43 Replacement CPP100 – CPP120 Emergency maintenance, scheduled maintenance and non scheduled maintenance
NW70.60.15	Asset Management Lifecycle Budget Forecasting Process	Describes the process used to forecast maintenance expenditure and replacement expenditure required as part of Orion's lifecycle management process.	CPP30 – CPP43 Replacement CPP100 – CPP120 Emergency maintenance, scheduled maintenance and non scheduled maintenance

	Network Architecture Review – Subtransmission	Examines the subtransmission topologies as part of an overall review of network design principles.	CPP1 – CPP20 Major Projects CPP51 and CPP52 Reinforcement
NW70.60.06	Network Architecture Review – 11kV	Examines the 11kV configuration as part of an overall review of network design principles.	CPP1 – CPP20 Major Projects CPP51 and CPP52 Reinforcement
NW70.60.10	Demand Side Management Review – Stage 1	Summarises the problems or opportunities where demand side management may be able to provide a cost effective solution.	CPP1 – CPP20 Major Projects CPP51 and CPP52 Reinforcement
NW70.60.11	Demand Side Management Review – Stage 2	Determines the likelihood of demand side management making a difference, identifies the most likely initiatives and conducts an initial cost-benefit analysis on each of these.	CPP1 – CPP20 Major Projects CPP51 and CPP52 Reinforcement

Appendix 22

Consultants' reports

Consultants' reports

IM D3(1)(a) and (b) and (2)

Consultants' reports relied on in CPP proposal					
CPP proposal reference	Consultant	Report	Date	Commissioned for CPP proposal	Relevance to CPP Proposal
Appendix 1	PwC	Addressing catastrophic events under price –quality regulation	Dec 2012	Yes	Independent review of our price path proposal with specific attention to our proposed ex-post recovery of the impact of the catastrophic earthquake events on our business, through prices
Appendix 2	NERA	Review of PwC report on addressing catastrophic events under price – quality regulation	Feb 2013	Yes	Independent review of PwC's report
Appendix 3	LineTech	Independent Engineer's Report – Quality Standard Variation	Dec 2012	Yes	Review of our proposed quality standard variation in accordance with CPP IM 5.4.5(c)
Appendix 11	Marsh	Orion's Network Catastrophe Insurance, Material Damage Insurance, Business Interruption Insurance, An Expert Report For Orion And The Commerce Commission	Oct 2012	Yes	Independent review of the insurance practices of owners of electricity transmission and distribution assets including Orion
Appendix 14	SKM	Independent Engineer's Report on the Asset Adjustment Process of Orion NZ Ltd	Oct 2012	Yes (as part of s53ZD Notices)	Independent review of our proposed adjustments to the Initial RAB in accordance with EDB IMs 2.2.1
Appendix 16	LineTech	Independent Engineer's Report on non standard asset lives for 'peak load and mobile generation', and 'power factor correction' assets	Dec 2012	Yes	Independent review of asset lives for which no standard life is prescribed
Appendix 32	Rider Levett Bucknall	Quantity Surveyor Report	Oct 2012	Yes	Estimates of annual increases in construction costs for the Canterbury region over the CPP regulatory period
Appendix 33	Davis Langdon	Quantity Surveyor Report	Oct 2012	Yes	Estimates of annual increases in construction costs for the Canterbury region over the CPP regulatory period
Appendix 34	Ian Harrison	Quantity Surveyor Report	Nov 2012	Yes	Estimates of annual increases in construction costs for the Canterbury region over the CPP regulatory period

Kestral Group	Resilience Lessons: Orion's 2010 and 2011 Earthquake Experience	September 2011	No	Independent review of Orion's earthquake preparedness and response
EA Technology Limited	Orion Networks AMMAT Review 2012	23 October 2012	No	Independent review of Orion's asset management processes using the Commission's Information Disclosure AMMAT framework
EA Technology Limited	Application of CBRM with Orion New Zealand	Marsh 2012	No	Report summarising the models developed for and the application of CBRM to Orion's key asset groups undertaken by EA Technology
SKM/PwC	Report to the Electricity Networks Association - ODV Handbook	9 August 2010	No	Presents industry wide construction costs for common electricity distribution assets, used as benchmarks against our own data prepared for the same purpose
MWH	Environmental Performance Assessment Prepared for Orion New Zealand Ltd	April 2009	No	Assessed our environmental performance with particular focus on the impact of investment decisions on the environment. This report summarises and reassesses original assessments undertaken in 2007

Appendix 23

References to AMP

AMP references

IM D3(3)

2012 AMP information included in CPP proposal in response to Schedule D and subpart 4, section 8 of Part 5 of the CPP IMs		
CPP proposal reference	Description	2012 AMP reference
Section 2.2.5	Description of organisation structure	2.4 Management responsibilities
Section 6.2.7	System security planning criteria, which are relevant to network performance (as addressed in section 6) and network planning (as addressed in section 9)	5.3.1 Security standard
Section 9.4.1 Our asset management plan	Provides an overview of the 2012 and 2013 AMPs	2.1 Purpose of our AMP
Section 9.4.1 Relationship between our AMP and our mission, corporate plans and objectives	Explains the interrelationships between the AMP and Orion's strategic plans and objectives	2.2 Business plans and goals
Section 9.4.3 Asset management process	Sets out the core steps of our asset management planning process	2.6 Asset management process
Section 9.5 Asset management drivers	Describes the core drivers for our asset management plans	2.5 Asset management drivers and 2.6.4 Introduction of new equipment types
Section 9.5.4 Information and systems	Describes the key asset information and systems relevant to our asset management planning	2.7 Systems and information
Section 9.6.1 – 9.6.10 Service categories, measures and targets	Defines service measures and targets (note this CPP Proposal includes targets which supersede those set out in the 2012 AMP, and which will be reflected in our 2013 AMP)	3.1 Introduction to service levels, 3.3 Service level measures and 3.4 Service level targets
Section 9.6.11 Determining service targets	Describes how service measures and targets have been derived in the past through consultation with consumers and other stakeholders	3.2 Consumer consultation
Section 9.6.12 Performance against service targets	Shows how we have performed against our service level targets for the current period	8 Evaluation of performance (data extracted from our 2008 – 2012 AMPs). Note we did not publish a 2011 AMP due to the need to focus our resources on the earthquake response
Section 9.7.2 Description of our distribution area	Describes the largest connections to our network	4.1.4 Large consumers,
Section 9.7.3 Network configuration	Describes the configuration of our network including a description of the points of supply, subtransmission system and zone substations	4.1 Network overview and 4.2 Network justification 5.2 Network architecture
Section 9.7.4 Distribution substations	Describes our distribution substation arrangements	4.4 Substations
Section 9.7.5 Low voltage network	Describes our LV network arrangements	4.8 Overhead lines – 400V and 4.12 Underground cables – 400V

Section 9.7.6 Secondary systems	Describes our communications, load management systems, DMS, metering and generation assets and systems	4.18 Generators, 4.20 Communications, 4.21 Load management systems, 4.22 Distribution management systems, 4.23 Metering
Section 9.8.1 Forecasting demand	Describes our approach to demand forecasting	5.1 Introduction to network development
Section 9.8.2 Key demand forecasting assumptions	Sets out the key assumptions relevant to demand forecasting	5.1 Introduction to network development, 5.4 Energy, demand and growth
Section 9.8.3 Method and assumptions for determining GXP and zone substation forecasts	Describes our load forecasting methodology and linkages to local TLA plans	5.4.2 Methodology for determining GXP and zone substation load forecasts
Section 9.8.4 Observed and extrapolated growth	Presents our load forecasts for the CPP regulatory period, and beyond to the end of the ten year AMP planning period	5.4.1 Observed and extrapolated growth
Section 9.8.5 GXP and zone substation load forecasts	Presents our load forecasts across our network. Note the CPP Proposal forecasts have been updated since the 2012 AMP was published. Our 2013 AMP forecasts will be consistent with these.	5.4.3 Transpower GXP load forecasts and 5.4.4 Orion urban zone substation load forecasts and 5.4.5 Orion rural zone substation load forecasts
Section 9.9.1 Introduction to Risk Management	Describes risk management responsibilities and processes	6.1 Introduction to Risk Management
Section 9.9.2 Risk management policies and plans	Describes our key risk management policies and plans	6.1.4 Risk management plans
Section 9.9.3 Risk assessments and mitigation measures	Describes our assessments of our key risks and mitigation measures we have adopted for business risks	6.2 Governance and operational business risks, 6.3 Safety, 6.4 Environmental management
Section 9.9.4 Risk assessments – network performance	Describes our assessments of our key risks we have adopted for network performance	6.5 Network risk analysis, 6.6 Interdependence, 6.7 Natural Disaster, 6.8 Asset failure
Section 9.9.5 Mitigation measures – network performance	Describes the mitigation measures we have adopted for network performance	6.9 Mitigation measures
Section 9.11.3 Project and programme deliverability	Explains our philosophy for project delivery	9.3.4 Project prioritisation
Section 9.13.6 Planning standards and key assumptions	Outlines the key standards and assumptions relevant to network planning	5.3 Planning criteria
Section 9.13.7 Network gap analysis	Assesses the degree to which we meet our security of supply standards	5.5 Network gap analysis
Section 9.13.10 Non-network solutions	Describes the extent to which we have considered non-network solutions in addressing network constraints	5.3.5 Non-network solutions
Asset Management Reports	Describes each asset category, asset quantities, condition and life cycle asset management plans	4.5 – 4.24 Asset sections

Appendix 24

Asset Management Policy

Asset Management Policy



Table of Contents

1	Introduction	4
2	Network summary	4
3	Aims and Objectives	6
4	Asset Management Benefits	7
5	Drivers	8
5.1	Investment principle.....	8
5.2	Business drivers	9
6	Service Levels	11
7	Relevant Policies and Planning Standards	11
7.1	Statutory Compliance	11
7.2	Asset lifecycle management.....	11
7.3	Asset management reports	12
7.4	Design standards.....	12
7.5	Technical specifications	13
7.6	Equipment specification	14
7.7	Operating standards	15
7.8	Network code.....	17
7.9	Consultants and contractors.....	17
7.10	Document control process.....	18
8	Asset Management Approach	18
8.1	Asset management process	18
8.2	Planning priorities	19
8.3	Asset management planning.....	20
8.3.1	Maintenance plan.....	20
8.3.2	Replacement plan	20
8.3.3	Creation/acquisition plan.....	20
8.3.4	Disposal plan	20
8.4	Introduction of new equipment types.....	20
8.5	Network development.....	20
9	Asset Maintenance Practices	21
9.1	Maintenance Practices	21
9.2	Time Based Maintenance.....	21
9.3	Condition Based Maintenance	22
9.3.1	CBRM	22
9.3.2	Asset management	22
9.3.3	Risk management	23
9.3.4	CBRM methodology.....	23

9.4	Reliability Based Maintenance	24
9.5	Corrective Maintenance	25
10	Asset management structure.....	25
11	Asset data.....	25
12	Asset risk management plan.....	26
12.1	Risk management tools	26
12.2	Safety risk management.....	27

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.

The damage to the network has compromised its performance, resulting in more network outages than experienced before the earthquakes.

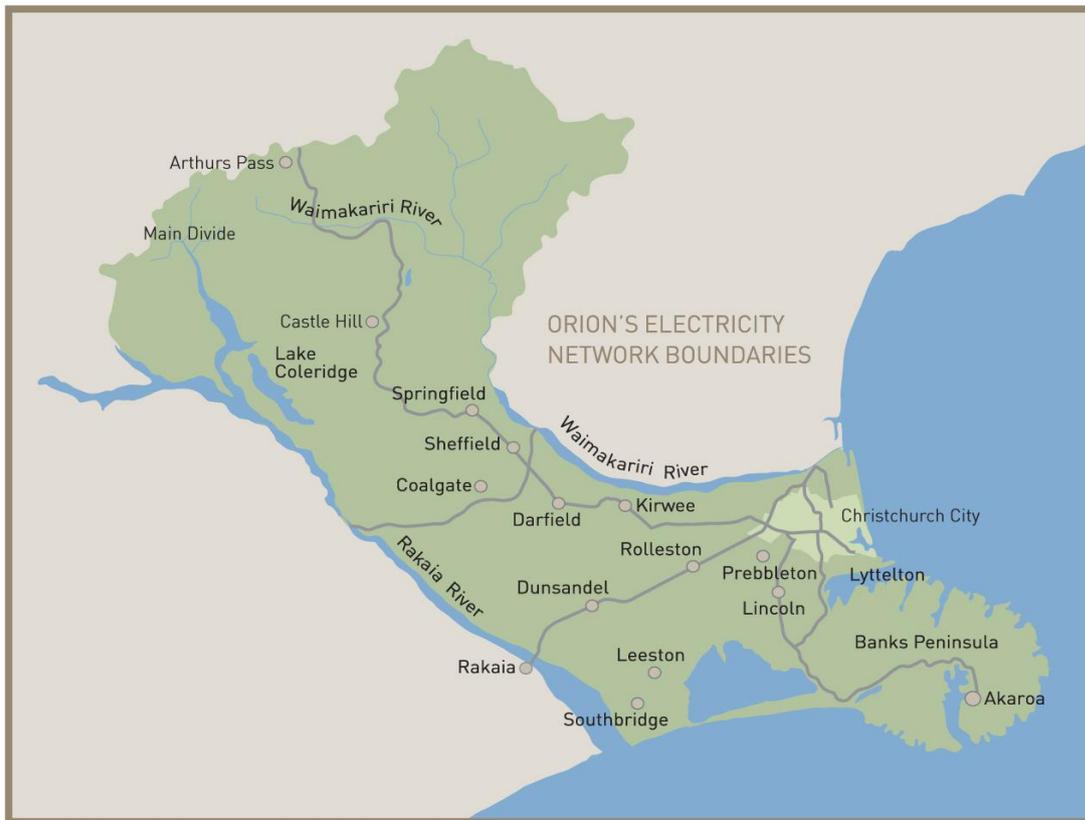
Over the years we have managed our business efficiently and prudently. We have insured our assets where it is economically viable to do so and we have invested to enhance the resilience and diversity of the network. Orion believes that the relative lack of earthquake-related damage to our key substations, 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.

2 Network summary

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 wellbeing. 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 customers, 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 customers – over 85% – are residential households. The rest are commercial or industrial premises. Business customers use around 60% of the electricity delivered via our network, while residential customers account for the other 40%. To reach all of our customers, 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.

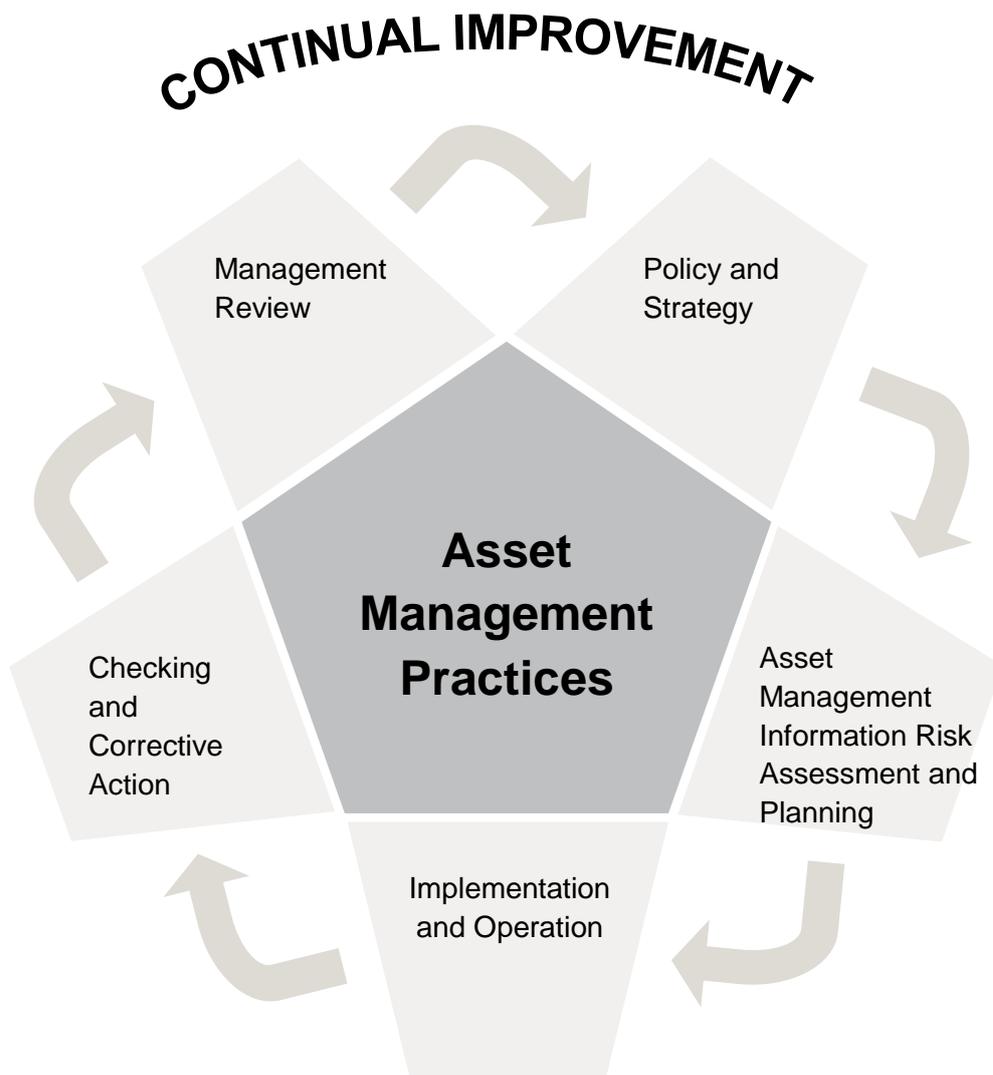
Network Summary	At 31 March 2012
Number of customer connections	190,682
Network maximum demand (MW)	633
Electricity delivered (GWh)	3,070
District/zone substations	52
Distribution/network substations	10,673
Kilometres of 66kV line and cable	200
Kilometres of 33kV line and cable	336
Kilometres of 11kV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

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

3 Aims and Objectives

We aim to be New Zealand's leading utility network company. To achieve this, we focus on managing our assets prudently to provide a reliable and high quality service into the future. We use innovative asset management practices to ensure electricity is delivered efficiently to consumers over the long term. Our objective is to optimise the lifecycle costs for each network asset group (including creation, operation, maintenance, renewal and disposal) to meet agreed service levels and future demand. We undertake 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 goal is to provide and operate Orion's electricity network while meeting agreed levels of service, quality, safety and profitability.



4 Asset Management Benefits

Adopting good asset management practices provides benefits for Orion and consumers across the following dimensions:

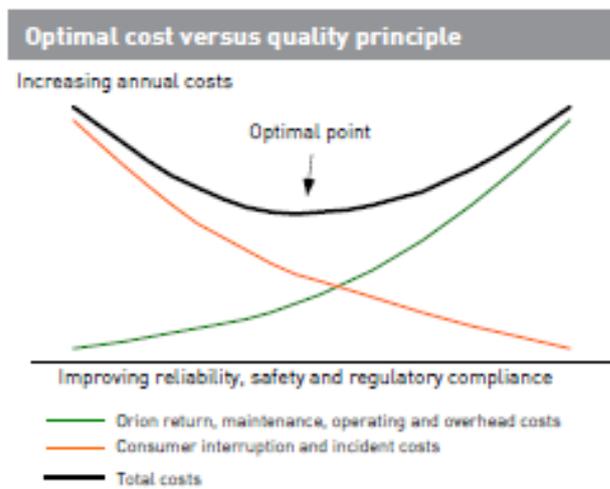
- Reduced risk – asset management will lead to greater knowledge of assets, failure mechanisms and network risks, which allows for better development of mitigation strategies to reduce the impact when the risks occur.
- Increased operational cost efficiency through reduced maintenance expenditure as unplanned and emergency events reduce in frequency and severity, and as scheduled maintenance can be planned to ensure appropriate resources, parts, optimised labour costs, etc,
- Increased capital efficiency through optimisation of maintenance and replacement expenditure to achieve lower asset lifecycle costs.
- Stronger capability for service delivery through improved reliability of the network assets and reduced unplanned interruptions.

- Improved safety through setting prescribing procedures that ensure all maintenance of assets is carried out in the safest manner possible.

5 Drivers

5.1 Investment principle

When we extend, replace, maintain and operate our network we consider the balance between cost and the quality of supply provided. The optimum point of investment in the network is achieved when the value of further expenditure would have exceeded the value of benefits to our consumers. This concept is illustrated in the following diagram.



Put simply, we seek to find the right balance between cost and the quality of our electricity delivery service. We seek to achieve this optimal point by economic analysis when we develop asset management plans for our assets, this includes considering a range of alternatives (e.g. maintenance versus renewal versus non-network solutions) to arrive at the minimum total cost to consumers and Orion.

To achieve optimal outcomes, we also commit significant resources to participate actively in the consultation phase of national rules and regulations. It is important that rules and regulations that affect our industry are well-informed, principled and practical. This includes balancing the benefits of greater service levels for consumers with the increase in costs required to achieve those service levels.

The speed at which new asset and systems technologies become available has increased in the last decade. We welcome these new initiatives and are committed to keeping up-to-date with technological advancements.

In line with our 'optimal point' approach above, we introduce new technology only when it results in an economic balance of cost and network performance. We then modify our standards and specifications to include the initiative.

More detail on technology initiatives is discussed in context within our AMP, for example:

- Ground Fault Neutraliser (GFN) technology at rural zone substations
- Modern communications technologies
- Partial discharge testing and corona imaging technologies

5.2 Business drivers

Our top priority is the efficient and effective management of our electricity network. We aim to provide consumers with a high level of service, a reliable and secure supply and competitive prices. We also aim to provide our shareholders with an attractive risk adjusted return on their investment.

The main business drivers which define the need, priority and scope for improved asset management practices within Orion are summarised below:

Safety

We are committed to meeting our safety obligations. We will:

- 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.

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.

Customer service

Consumers require electricity to be delivered safely, reliably, efficiently and economically. We use asset management techniques to satisfy these requirements and we seek to:

- identify and satisfy consumer requirements
- improve understanding of service level options, measures and associated costs.

Environmental responsibility

We are committed to being environmentally responsible. Legislation such as the Resource Management Act 1991 and our own environmental sustainability policy govern our activities.

Our major identified responsibilities are:

- a duty to avoid discharge of any contaminants into the environment
- a duty to avoid unreasonable noise
- a duty to avoid, remedy or mitigate any adverse effect on the environment.

We also 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. We have now included specific carbon costs to the cost of electrical losses into our investment process.

Underground conversion projects are an asset enhancement driven partly by our concern for the visual environment.

Economic efficiency

We aim to ensure that the financial returns on our network investment are appropriate. Our asset management practices support economic efficiency as they:

- provide a basis to monitor asset performance and utilisation
- enable asset managers to plan and prioritise maintenance, renewal and growth expenditure
- quantify risk, and minimise high impact failures
- extend the life of assets and optimise the trade-off between maintenance and replacement
- tender all work to competent contractors and thus ensure the best price for specific works
- conduct an economic cost benefit analysis on all major projects
- optimise distribution network losses and network utilisation (load factor).

Legislation

Our aim is to achieve material compliance with all relevant legislation, regulations and codes of practice that relate to how we manage our electricity distribution network, including:

- Electricity Act
- Local Government 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
- Electricity Information Disclosure Requirements
- Public Bodies Contract Act
- NZ Electrical Codes of Practice
- Public Works Act
- Civil Defence Emergency Management Act
- Electricity Amendment Act
- Resource Management Act.

Material compliance is achieved using our risk based approach to ensuring compliance. This ensures that we focus on the significant issues.

A list of our obligations is set out in the Statutory Compliance Manual.

6 Service Levels

The key to the successful management of Orion’s assets is meeting the expectations of our stakeholders. This is consistent with our ‘mission’ and statement of intent (SOI). Our SOI contains specific service level targets for reliability (SAIDI, SAIFI) and other aspects of our business, some of which are outside the scope of the Asset Management Policy.

They encompass consumer-related service requirements and other requirements relating to our asset management drivers as defined in the section above.

Our service level targets are based on a balance of:

- the results of consumer and stakeholder consultation
- safety considerations
- regulatory requirements
- international best practice
- past practice.

We have a range of service targets under each of the following service classes:

- Network reliability
- Network restoration
- Network capacity
- Power quality
- Safety
- Customer service
- Environment
- Economic efficiency

See the Asset Management Plan (AMP) for specific current and future year service targets.

7 Relevant Policies and Planning Standards

7.1 Statutory Compliance

Asset management is to be carried out in accordance with Orion’s Statutory Compliance manual. Priorities are set using our risk based approach.

7.2 Asset lifecycle management

The relevant asset lifecycle policies and other management documents are set out below:

Annual Work Plan	NW70.01.17
Asset Management Plan	NW70.60.01
Asset Performance Report	NW71.01.02
Business Continuity Plan - Infrastructure Management	NW70.60.04
Business Plan - Network	NW70.20.00
Easements - Agreement to Grant	NW70.00.13

Environmental - Management Manual	NW70.00.08
Health and Safety - Management Manual	NW70.00.16
Over-Boundary Maintenance Policy	NW72.00.00
Overhead Line - Maintenance Costs	NW72.01.01
Safety Management System Manual	NW70.00.21
Underground Conversion	NW70.00.10

7.3 Asset management reports

Each asset type has a report that provides a description and considers aspects of performance, maintenance and/or renewal:

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 Lines - 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

7.4 Design standards

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 we have design standards and drawings that are available for use by approved designers/contractors. Normally we only accept designs that conform to these standards. The relevant standards that must be complied with for network design are set out below:

Cables - Underground Cable Design	NW70.52.01
Earthing - Design	NW70.59.01
Ground Fault Neutraliser - Design Application Guide	NW70.57.06
Metering Design	NW70.55.01
Network Asset Identification	NW70.00.12
Network Design Overview	NW70.50.05
Overhead Line - Design Manual	NW70.51.02
Overhead Line - Design Standard	NW70.51.01
Overhead Line - Technical Manual	NW70.51.04
Overhead Line - Worked Examples	NW70.51.03

Protection - Design	NW70.57.01
Protection - Design - Application Guide Distribution Feeder and Transformer	NW70.57.03
Protection - Design - Subtransmission	NW70.57.02
Railway Crossing Application Form (KiwiRail)	NW70.50.06
SCADA Functional Specification for Remote Sites	NW70.56.01
Substation - Customer Premises	NW70.53.02
Substation - Design	NW70.53.01

7.5 Technical specifications

A comprehensive set of specifications and procedures (work instructions) for performing different activities on our network has also been developed. These are intended for authorised contractors who tender for any work on our network. The relevant specifications that must be complied with for performing activities (e.g. maintenance, renewals and network development projects) on our network are set out below:

Overhead Network

ABI maintenance	NW72.21.04
Excavation Protocols - Near Electrical/Telecommunication Lines	NW72.21.23
Overhead Line - Construction Checklist	NW72.31.01
Overhead Line - Inspection & Assessment	NW72.21.11
Overhead Line - Inspection Sheet	NW72.31.02
Overhead Line - Retighten Components	NW72.21.03
Overhead Line - Tower Painting	NW72.21.05
Overhead Line - Visual Inspection of HV	NW72.21.09
Overhead Line - Work	NW72.21.01
Poles - Attachment Engineering Agreement - Between Orion & Telecom	NW72.21.16
Poles - Ownership Agreement - Between Orion & Telecom	NW72.21.22
Poles - Shared Use - Attachment Guideline	NW72.21.17
Poles - Shared Use - Engineering Practice	NW72.21.14
Poles - Shared Use - Engineering Practice - Telco Service Drops (Telstra)	NW72.21.15
Standard Construction Drawing Set - Overhead	NW72.21.18
Thermographic Survey of HV Network	NW72.21.10
Tower Foundation Inspections	NW72.21.19
Vegetation Cutting Notification	NW72.14.01
Vegetation Work Adjacent to Overhead Lines	NW72.24.01
Vibration Damper Installation	NW72.21.13

Underground Network

Cables - 66kV Civil Construction - McFaddens to Dallington	NW72.22.04
Cables - 66kV Installation - McFaddens to Dallington	NW72.22.05
Cables - Excavation & Backfilling	NW72.22.02
Cables - Installation & Maintenance	NW72.22.01
Cables - Recording Cables & Associated plant	NW71.12.03
Cables - Testing	NW72.23.24
Oil Filled Cable Contingency Plan	NW72.12.02
Distribution Enclosure Installation	NW72.22.03
Duct Installation For Future Use	NW72.12.01
Low Voltage UG Network Inspection	NW72.21.12
Standard Construction Drawing Set - Underground	NW72.21.20

Substations

Building Substation - Install Equipment	NW72.23.18
Distribution Substation - Inspection	NW72.23.03

Distribution Substation - Maintenance	NW72.23.05
Distribution Transformer - Maintenance	NW72.23.02
Earthing - Installation	NW72.28.01
Earthing - Testing	NW72.28.02
Kiosk Substation - Installation	NW72.23.14
Mineral Insulating Oil - Maintenance	NW72.23.01
Network Substation - Inspection	NW72.23.04
Network Substation - Maintenance	NW72.23.06
Network Substation - Seismic Strengthening	NW72.23.19
OCB - Servicing After Fault Operation	NW72.23.15
Partial Discharge Tests	NW72.27.03
Pole Mounted Substation - Fuse Maintenance	NW72.23.20
Power Transformer - Maintenance	NW72.23.25
Protection	NW72.27.02
Regulators - Install or Change on O/D Pad Mounted Sites	NW72.23.22
Standard Construction Drawing Set - Substations	NW72.21.21
Testing and Commissioning of Secondary Equipment	NW72.27.04
Transformer - Installation	NW72.23.16
Unit Protection 11kV - Maintenance Tests	NW72.27.01
Zone Substation - Inspection	NW72.23.13
Zone Substation - Maintenance	NW72.23.07

Miscellaneous

Fuse Application on the Network	NW72.20.06
Grounds Maintenance	NW72.20.07
Metering Installations intended for Energy Trading & compliance with EMCO	NW72.25.07
Orion Check Metering with Transpower at POS	NW72.25.03
Ripple Control System - Technical Details	NW70.26.01
Ripple Equipment Maintenance	NW72.26.02
SCADA Master Maintenance	NW72.26.04
SCADA RTU Maintenance	NW72.26.05
Tariff Meter Individual Testing	NW72.25.04

7.6 Equipment specification

We seek to standardise the equipment used to construct components of our network. To this end, a set of specifications detailing accepted performance criteria for significant equipment has been developed. The relevant specifications that must be complied with for supply of network components are set out below:

Cable - Distribution - 11kV	NW74.23.04
Cable - Distribution - 400V	NW74.23.11
Cable - Subtransmission - 33kV	NW74.23.14
Cable - Subtransmission - 66kV - (Bromley to Dallington)	NW74.23.32
Cable - Subtransmission - 66kV - (McFaddens to Dallington)	NW74.23.29
Cable - Subtransmission - 66kV - (Middleton)	NW74.23.27
Cable - Subtransmission - 66kV - 1600mm ² Cu XLPE	NW74.23.31
Cable - Subtransmission - 66kV - 300mm ² Cu XLPE	NW74.23.30
Circuit Breaker - 11kV indoor	NW74.23.13
Circuit Breaker - 33kV indoor	NW74.23.28
Circuit Breaker - 66kV	NW74.23.25
Communication System	NW74.23.21
Cross Arms - Wooden	NW74.23.19

Current Transformer - 66kV	NW74.23.26
Current Transformer - 66kV - Outdoor	NW74.23.18
Earthing Equipment - Approved and Application	NW74.23.20
Insulator - HV Overhead Lines	NW74.23.10
Kiosk Shell - Full	NW74.23.01
Kiosk Shell - Half	NW74.23.02
Kiosk Shell - Quarter	NW74.23.03
Overhead Conductors	NW74.23.17
Pole - Hardwood	NW74.23.08
Pole - Softwood	NW74.23.06
Regulator - 11kV	NW74.23.15
Ripple Control System	NW74.23.09
Surge Arrestor - 66kV	NW74.23.12
Switchgear - 400V - Approved and Application	NW74.23.23
Transformer - Ground Mounted Distribution - 200 to 1000kVA	NW74.23.05
Transformer - Primary - 33/11kV 2.5MVA	NW74.23.22
Transformer - Primary - 66/11kV 11.5/23MVA	NW74.23.16
Transformer - Primary - 66/11kV 40MVA	NW74.23.24
Transformer - Primary - 66/11kV 7.5/10MVA	NW74.23.07

7.7 Operating standards

To ensure the wide variety of equipment on our network is operated safely with minimum impact on our consumers, we have developed an operating instruction for each different type of equipment on our network. We add to these when any new equipment is introduced (see AMP section 2.6.4 – process for the introduction of new equipment).

The relevant policies that must be complied with for operating equipment are set out below:

11kV ABI CEC HM-L (Motorised)	NW72.13.89
11kV ABI EPS1FS - Hot Stick Operated ABI	NW72.13.95
11kV ABI NASAT Remote Controlled	NW72.13.92
11kV AIU/MSU Magnefix MD4	NW72.13.81
11kV Circuit Breaker Holec Xiria	NW72.13.70
11kV Enermet Ripple Plant	NW72.13.211
11kV Fuse switch Brush HFU	NW72.13.72
11kV Fuse switch F&P IB	NW72.13.74
11kV Fuse switch L&C GF3	NW72.13.79
11kV Fuse switch Statter VAA	NW72.13.86
11kV Fuse switch Statter VL	NW72.13.87
11kV Fuse switch Statter VL/2-OD	NW72.13.88
11kV GCB South Wales HK12SF6	NW72.13.56
11kV Line Fault Indicator LINETROLL 3500	NW72.13.96
11kV Line logger	NW72.13.91
11kV Neutral Earthing Resistor	NW72.13.90
11kV OCB Brush VBAD	NW72.13.28
11kV OCB Brush VSI	NW72.13.30
11kV OCB C&F ULB1	NW72.13.32
11kV OCB C-P ALA3	NW72.13.33
11kV OCB F&P BVP3,4 & BVU3,4	NW72.13.34
11kV OCB GEC-AEI BVP17 & BTVP17	NW72.13.23
11kV OCB Reyrolle LA23T	NW72.13.51

11kV OCB South Wales C4X,D4,D4X	NW72.13.57
11kV OCB South Wales D4X,D6X	NW72.13.62
11kV OCB Statter AC01	NW72.13.54
11kV OCB Statter AC2	NW72.13.55
11kV OCB/VCB Reyrolle LMT & LMVP	NW72.13.52
11kV Oil switch L&C J4	NW72.13.78
11kV Oil switch Reyrolle IA23	NW72.13.83
11kV Pole VCB Control Relay Microtrip 2	NW72.13.49
11kV Pole VCB Cooper V4H 1ph	NW72.13.45
11kV Pole VCB McGraw Edison KF	NW72.13.46
11kV Pole VCB McGraw Edison KFE	NW72.13.47
11kV Pole VCB McGraw Edison KFME	NW72.13.48
11kV Pole VCB Nu-Lec Type N12	NW72.13.41
11kV Pole VCB Nu-Lec Type U12	NW72.13.42
11kV Sectionaliser McGraw Edison GN3E	NW72.13.80
11kV Sectionaliser Reyrolle OYS	NW72.13.84
11kV VCB Holec SVS	NW72.13.63
11kV VCB Toshiba VK10J25	NW72.13.64
11kV VCB/SF6 S&C Vista	NW72.13.66
11kV Voltage Regulator ASEA	NW72.13.203
11kV Voltage Regulator EEC	NW72.13.202
11kV Voltage Regulator Ferranti	NW72.13.201
11kV Voltage Regulator Siemens	NW72.13.204
33kV Fuse S&C SMD-20	NW72.13.19
33kV GCB Merlin Gerin (Transpower owned)	NW72.13.20
33kV OCB ASEA HLC & HKCYB	NW72.13.12
33kV OCB GEC OIKW3	NW72.13.14
33kV OCB McGraw Edison RVE	NW72.13.16
33kV OCB Sace RGE36	NW72.13.17
33kV OCB Sprecher	NW72.13.18
33kV VCB Tamco - VH3/VH3D	NW72.13.94
66/11kV Transformer - Pauwels Type ORF 40/140	NW72.13.215
66kV ABI SDCEM SR16200	NW72.13.11
66kV GCB Alstom DT1-72.5 (SF6)	NW72.13.10
66kV OCB ASEA HLC	NW72.13.07
66kV OCB Reyrolle 660SM120	NW72.13.08
66kV OCB Sprecher HGF309	NW72.13.09
Ground Fault Neutraliser	NW72.13.99
Hotstick Line Sniffer	NW72.13.111
Meter - Power Quality GE Multilin	NW72.13.120
OCB - AEI BVP17 Maintenance	NW72.13.03
OCB - South Wales 11kV CX, DX Maintenance	NW72.13.02
Parabolic Pinpointer	NW72.13.110
Phasing Set - Fameca 4000	NW72.13.112
Relay - Feeder Management GE Multilin SR760	NW72.13.101
Relay - Feeder Management SEL 587	NW72.13.102
Relay - Feeder Protection MiCOM P120,122,123	NW72.13.103
Relay - Line Differential GE Multilin L90	NW72.13.105
Relay - Transformer Differential GE Multilin T60	NW72.13.106
Relay - Transformer Management GE Type SR745	NW72.13.100
Relay - Voltage Regulating a-eberle REG-D	NW72.13.107
Standby Generator - Simeon	NW72.13.210

Standby Generator Truck 350kVA	NW72.13.97
Standby Generator Truck 400kVA	NW72.13.109
Standby Generator Truck 440kVA	NW72.13.98
Static Generator Set 2500kVA	NW72.13.113
Transformer (Major) - Vacuum Filling	NW72.13.01

7.8 Network code

Our Network code is used to communicate with customers and contractors the general requirements for connecting to our network.

7.9 Consultants and contractors

We maintain relationships with a number of consultants and contractors that work with us to meet our asset management objectives. They do not have any management responsibilities but operate on a fixed scope and/or period contract to meet the specific needs of work/project requirements.

Works are identified through our capital works and maintenance programmes and subsequently approved in an annual budget. Identified works are then designed and completed using appropriate consultants and contractors.

All network maintenance and construction work (where possible and appropriate) is competitively tendered to selected contractors. The contract works are processed and managed by the Infrastructure management group.

The scope of out-sourced works to consultants and contractors can be outlined as:

Consultants

- expert advice
- detailed design.

Field services

- emergency response services
- spares and major plant services
- some specialist asset inspections and non-invasive/non-destruction testing
- maintenance of existing network infrastructure
- installation and replacement of new or existing network infrastructure.

The relevant policies that must be complied with for working with consultants and contractors are set out below:

Contract - Administration	NW73.10.07
Contract - Construction Audit Process	NW73.10.11
Contract - Evaluation of Tenders	NW73.10.13
Contract - Hazard Management	NW72.20.10
Contract - Management	NW73.00.03
Contract - Performance Monitoring	NW72.20.05
Contract - Post Contract Evaluation	NW73.10.16
Contract - Standard Document	NW73.00.01
Contract - Standard Procedure	NW73.00.02

Contract - Tender Procedures	NW73.10.09
Contract - Works - Externally Driven	NW73.10.14
Contract - Works - Internally Driven	NW73.10.08
Contractors - Authorised and Approved List	NW73.10.15
Event Reporting	NW72.11.03
Geomedia WebMap Contractor Website - TUA	NW70.00.20
Health and Safety Checklist	NW72.00.01
Pricing Request	NW73.10.10
Working near the Orion network - Competency	NW72.11.02
Works - Emergency	NW72.20.03
Works - Environmental Audit	NW73.10.18
Works - General Requirements	NW72.20.04
Works - Management - Audit Procedure	NW73.10.17

7.10 Document control process

Our Data Manager processes these ‘controlled documents’ using our document control process. Extensive use is made of an in-house process control application that encompasses a restricted-access area on our website to make standard documents and drawings accessible to approved contractors and designers.

We plan to introduce a document management system to help track and manage these documents over the next few years.

The relevant policies to be complied with for document management are set out below:

Document Control	NW70.50.03
Draughting and Records	NW70.50.02

8 Asset Management Approach

8.1 Asset management process

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. These techniques are used to improve our performance so we can meet our network reliability targets. We have engaged EA Technology Limited to develop Condition Based Risk Management (CBRM) models for the majority of our network assets. These models use the results from our condition monitoring programmes and will underpin the economic justification for our expenditure forecasts. We are currently uploading our latest post-earthquake asset data into the models. This project will provide valuable learning opportunities for our lifecycle engineers as we develop CBRM expertise in-house.

Generally assets are not replaced on age alone, but are kept in service until their continued maintenance is uneconomic or until they pose a safety, environmental or reliability risk. Reliability performance is measured and used to identify areas where further maintenance is needed to improve our delivery service or where maintenance may be reduced without reducing service. We determine our maintenance priorities by following the general principle that the assets supplying the greatest number of consumers receive the highest priority.

Most other electricity distributors maintain electrical equipment only up to the boundary of a property. We, however, commit to maintaining the lines, poles and all other electrical equipment right up to the house or business building regardless of whether it is owned by us. We apply this policy to provide our community with the best possible service.

This is of particular benefit to customers by reducing restoration times after a significant weather event.

Our overall asset management process is as follows:



8.2 Planning priorities

Recent changes in regulations and industry codes of practice have highlighted the need to mitigate safety risks for the public, employees and contractors. Therefore we continue to:

- remove at-risk equipment
- increase security around substations and equipment
- tighten controls on equipment access.

In recent years we have focused on our ability to meet the growth needs of the community while ensuring appropriate reliability and security. Network security is always compromised during times when capital or maintenance works are carried out.

To mitigate risk associated with reduced security during these periods of change we:

- endeavour to plan work methods and contingencies to minimise any impact on the network
- use programmes that allow for contingency events, such as ensuring 66kV oil filled cable joint replacements are not compromised by other works

- programme works in a manner that provides consistent work for the skilled resources available
- are proactive in the development and retention of skilled resources for the future
- schedule works at non-peak times of the day / year.

8.3 Asset management planning

Our asset management planning processes involves creation of:

8.3.1 Maintenance plan

The ongoing day to day work plans required to keep the asset serviceable and prevent premature deterioration or failure. Three categories of maintenance are carried out:

- scheduled maintenance – work carried out to a predetermined schedule and allocated budget
- unscheduled maintenance – work that must be performed outside the predetermined schedule, but does not constitute an emergency
- emergency maintenance – work that must be done as a portion of the network requires immediate repair.

8.3.2 Replacement plan

These are major work plans that do not increase the asset's design capacity but restore, replace or renew an existing asset to its original capacity. Many assets are not maintained and instead are replaced at the end of their economic life, while other assets are assessed for the costs and benefits of maintenance versus replacement.

8.3.3 Creation/acquisition plan

This is capital work that creates a new asset or improves an existing asset beyond its existing capacity.

8.3.4 Disposal plan

This is any of the activities associated with disposal of a decommissioned asset.

8.4 Introduction of new equipment types

New equipment is reviewed to carefully establish any benefits that it may provide and full lifecycle costs. Introduction is planned to ensure that the equipment meets our technical requirements and provides cost benefits. It must be able to be maintained and operated to provide safe, cost effective utilisation to support our supply security requirements.

8.5 Network development

Maximum demand is the major driver of investment in our network. Developing our network to meet future demand growth requires significant capital expenditure. When scoping development projects we focus on energy and financial efficiency, consider new non-network solutions to meet energy demand, and assess longer term investment risks.

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.

Other significant demands on capital include:

- meeting safety and environmental compliance requirements with existing ageing equipment
- meeting and maintaining our security of supply standard
- meeting our reliability of supply targets.

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). In the medium term our maximum system demand is influenced by growth factors such as underlying population trends, growth in commercial/industrial output, and changes in land use in the rural sector and in the Christchurch urban area as the city redevelops post-earthquake.

9 Asset Maintenance Practices

We adopt whole lifecycle practices for our network assets and focus on optimising the lifecycle costs for each asset group to meet agreed service levels & future demand. Asset lifecycle management encompasses design, procurement, installation, operation, maintenance, decommission and disposal.

Asset lifecycle management comprises two types of activities (and expenditure):

- Maintenance (scheduled, non-scheduled and emergency) of assets throughout an asset's economic life, and
- Replacement of assets as they reach the end of their economic life.

Our asset lifecycle management approach focuses on maintaining assets so that they are in appropriate condition and replacing assets in a timely manner. Running assets to failure (electrically or mechanically) is not appropriate as the consequences of failure poses a significant risk to people and property, and are very costly to rectify.

9.1 Maintenance Practices

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.

9.2 Time Based Maintenance

Time based scheduled maintenance is usually carried out in line with asset manufacturer's recommended maintenance cycles. These scheduled maintenance programmes are documented in our Technical specifications.

9.3 Condition Based Maintenance

We are currently implementing a Condition Based Risk Management (CBRM) approach for replacement/renewal of assets.

We use a condition based asset management assessment to help predict asset replacement over time. We are currently transitioning from our existing in house condition based asset management model to a more detailed condition based risk management model developed by EA Technology Ltd (CBRM). For a period of time we will operate both systems until we fully transition to CBRM. For example, we need to ensure that the economic justification for money spent on asset replacement generated from the new model is appropriate when compared to previous modelling and approaches. Our present assumption is that we will maintain our current level of maintenance expenditure which is based on our asset failure rates.

9.3.1 CBRM

CBRM is a structured process that combines asset information, engineering knowledge and practical experience to define future condition, performance and risk for network assets.

We have engaged EA Technologies Ltd to assist in developing CBRM models for the majority of our network assets. These models use the results from our condition monitoring programmes and will underpin the economic justification for our expenditure forecasts when fully developed.

Generally assets are not replaced on age alone, but are kept in service until their continued maintenance is uneconomic or until they pose a safety, environmental or reliability risk.

Reliability performance is measured and used to identify areas where further maintenance is needed to improve our delivery service or where maintenance may be reduced without reducing service.

We determine our maintenance priorities by following the general principle that the assets supplying the greatest number of consumers receive the highest priority, for example where the consequences of failure are high (such as a subtransmission transformer) the asset may be replaced when its condition is moderate, whereas if the consequences of failure are very low, then it may only be replaced when it fails.

CBRM originated from two key drivers, which have increasingly become interlinked, specifically asset management and risk management

9.3.2 Asset management

In order to manage the renewal of ageing networks cost effectively, it is vital to define current asset condition and link this to current and future performance. This is achieved through:

- Effective, non-invasive condition assessment techniques
- Improved information management

- Systematic application of practical knowledge and experience of degradation, failure, condition assessment, effects of environment, duty, maintenance history etc.

With the introduction of modern electronic devices, the monitoring and control of equipment has improved. Coupled with our inspection rounds, we are able to collect good quality data on the reliability and condition of our assets. This information can then be used to better determine / inform optimised maintenance schedules.

There are economic ramifications associated with this increase in testing and monitoring, however this can be offset if less time based maintenance is undertaken. While we develop the systems to enable effective condition monitoring we will continue to use a scaled down version of the existing time based schedule.

9.3.3 Risk management

The facility to quantify and manage risk is increasingly recognised as a primary business driver, both by electricity company managers and industry regulators. This requires capturing the experience of asset performance, degradation and risk of failure.

9.3.4 CBRM methodology

CBRM combines these two areas into a sophisticated methodology for factoring the risks and consequences of failure into condition-based asset management, making the new CBRM solution an extremely powerful asset management system

An overview of the CBRM process is shown in Figure 1.

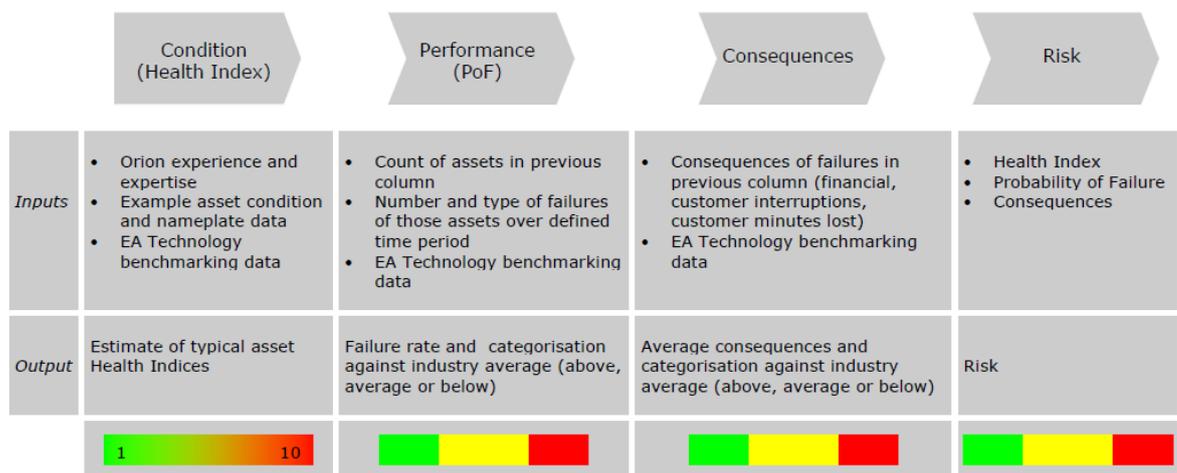


Figure 1 Overview of CBRM asset management process

The process can be summarised by a series of sequential steps as follows:

1. **Define asset condition.** 'Health indices' for individual assets are derived and built for different asset groups. Current health indices are measured on a scale of 0 to 10, where 0 indicates the best condition and 10 the worst.

2. **Link current condition to performance.** Health indices are calibrated against relative probability of failure (PoF). The health index / PoF relationship for an asset group is determined by matching the health index profile with the recent failure rate.
3. **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 health index profiles and the previously defined health index / PoF relationship.
4. **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.
5. **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.
6. **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.
7. **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.
8. **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.

We have applied the above steps to our network assets and asset models have been constructed and will be maintained for a number of asset types. Over time additional models will be developed.

9.4 Reliability Based Maintenance

This form of maintenance requires analysis of the failure modes of equipment. The maintenance schedule is modified to mitigate any issues / factors before the equipment fails. An example of this is the approach taken towards tap changers, in particular those manufactured by Fuller. These units are known to be problematic and as a result have been targeted for replacement with vacuum units which require less maintenance.

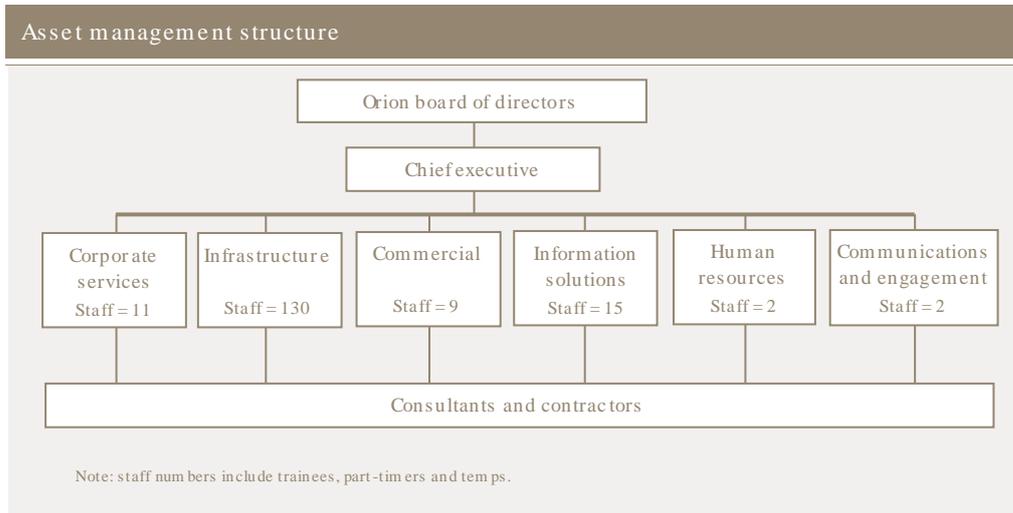
Again from a practical point of view this method of maintenance is one of the better types employed. Its downside however is that it requires prior knowledge and / or a lot of analysis of equipment failure modes.

9.5 Corrective Maintenance

Preventative maintenance approaches are not perfect however, and on occasion, equipment faults do occur in our network. In these cases, corrective maintenance is the most appropriate response. The frequency of these events is low.

10 Asset management structure

The asset management structure for our electricity assets is as follows:



Orion's directors are appointed by the shareholders to govern and direct Orion's activities. The board of directors is the overall and final body responsible for all decision-making within the company.

11 Asset data

The majority of our primary asset information is held in our asset register (WASP), 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 errors and improved information will always be required, we believe that our information for the majority of the network is accurate. Some information for older assets installed more than 15-20 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 the use of identification discs
- older air break switches and section fuses.

Refinement of 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 with new assets over time all estimated data will be superseded.

Currently the only area identified where information needs to be improved is associated with determining accurate connection assets of 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 high priority and information will be sourced associated with other inspection programmes over the next five years.

Details of current data, compliance inspections and maintenance regimes for each asset group are in the asset management report for the relevant asset.

12 Asset risk management plan

Our risk management process is based on the risk management standard AS/NZS4360:2004. We have aligned to our Civil Defence responsibilities using the ‘four R’s’ approach to resilience planning—reduction, readiness, response and recovery. We have identified the responsibilities of key Orion staff which help to manage risk.

Our Asset Risk Management Plan (NW70.60.02) details exposure to and mitigation measures for:

- Natural disaster
- Earthquake
- Flooding
- Slope hazard
- Snow hazard
- Wind hazard
- Network asset failure
- Contaminants entering the environment.

Also included is the approach to managing risk-based spares.

During the mid 1990s Orion 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.

12.1 Risk management tools

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 a 5 x 5 risk acceptability matrix.
- Quantate—a dedicated risk management software application that allows us to prioritise risk across our business with results presented on the bands of a risk acceptability chart.

We have not yet implemented Quantate past the stage of entering some existing asset risk assessments, and evaluating a small number of corporate risks, to provide a sample database for evaluation and recommendation purposes.

Prior to the February 2011 earthquake we made an initial presentation of the Quantate assessment of corporate risks to the Corporate Group in order to prepare for implementation across the whole business, the project stopped at the time of the February earthquake and has not yet been reactivated.

12.2 Safety risk management

While implementing our Safety Management System (SMS) for Public Safety we identified a need for a more comprehensive process for documenting risk mitigation actions. Quantate includes the functionality to provide this capability and additionally we have prepared a draft retrospective table of the mitigation decisions taken with respect to our Physical Security Plan.

In terms of security, the general principles are the prevention of unauthorised entry by children and opportunist intruders without specialised tools, and to slow determined intruders. This is achieved by having in place:

- suitable warning to ensure knowledge of the hazard
- reasonable measures to prevent access by members of the public
- additional measures to deter detect and slow determined intruders at sites with a higher risk.

In practice this is implemented as warning, barrier, warning, barrier, e.g.:

- warning sign on locked external door, warning sign on shrouded equipment: or
- warning sign on site perimeter fence, warning sign on internal switchyard fence.

Appendix 25

DSA (extract)

Extracts from Orion's Delivery Services Agreement (DSA).

5 DELIVERY SERVICES

5.1 The Distributor shall, in accordance with this Agreement:

5.1.1 provide Delivery Services including the provision of the Associated Services and such of the Discretionary Services as the Electricity Retailer may elect to acquire, to the Electricity Retailer in accordance with Good Industry Practice, subject to clause 5.2; and

5.1.2 use its reasonable endeavours to meet the Performance Targets;

5.1.3 use its reasonable endeavours in its negotiations with Transpower to ensure that transmission services are provided cost-effectively;

5.1.4 comply with MARIA, in so far as any obligations are placed on *Distributors* as defined in MARIA, in the context of providing Delivery Services;

5.1.5 comply with its obligations as a member of the Electricity Complaints Commissioner Scheme.

5.2 The Distributor shall use reasonable endeavours to provide continuous Delivery but does not guarantee that the Distribution Network will provide Delivery which is free from defects or interruptions. The Electricity Retailer shall ensure its contracts with Connected Customers contain a similar provision, to the effect that the Distributor does not guarantee continuous Delivery.

5.3 The Distributor shall accommodate the Electricity Retailer and all Other Electricity Retailers equitably with regard to the Delivery Services. If the Distributor is Involved in electricity retailing it shall at all times treat its electricity retailing activity in an economically equivalent manner to the Electricity Retailer and Other Electricity Retailers.

5.4 If an Electricity Retailer requests the Distributor to upgrade its Delivery Service or extend its Distribution Network, the Distributor may require the Electricity Retailer or the Connected Customer to enter into a Connection Agreement to record the terms agreed between the Distributor and the Electricity Retailer or Connected Customer in relation to the upgrade and/or extension.

5.5 The Distributor will consult with the Electricity Retailer on any material changes to the Asset Management Plan and consider any submissions made by the Electricity Retailer on the Asset Management Plan in good faith. For the avoidance of doubt the Distributor's obligation is to consult only, and the determination of the Asset Management Plan is a matter for the Distributor, at its discretion.

5.6 The Distributor may from time to time put in place a Non Performance Payment Schedule pursuant to which, upon the happening of certain events, the Distributor will make a payment to the Electricity Retailer in respect of the Connections affected by the event. A copy of the Non Performance Payment Schedule to apply from the Commencement Date is set out in Schedule

F. Any variation to a Non Performance Payment Schedule will be introduced pursuant to clause 4.4 and may not be materially inferior to the Electricity Retailer than any existing Non Performance Payment Schedule, without the consent in writing of the Electricity Retailer.

5.7 The Electricity Retailer acknowledges that there are existing arrangements and may be written agreements applying to a particular Connection. The Electricity Retailer may request from the Distributor details of any such arrangements or agreements applying to any particular Connection. Such arrangements or agreements shall continue to apply unless the Distributor agrees otherwise. Such arrangements or agreements may by way of example relate to matters such as plant ratings, electrical protection settings, use of land and buildings, accommodation of the Distributor's Equipment or general physical layout of plant.

6 INTERRUPTION TO DELIVERY

The Distributor may interrupt or reduce Delivery at any time the Distributor considers it appropriate to do so for planned or unplanned interruptions as follows:

6.1 Planned Interruptions

In situations where the Distributor determines the need for the interruption, in accordance with Good Industry Practice, at least two hours in advance, including:

6.1.1 To enable the Distributor to inspect, effect alterations, maintenance, repairs or additions to any part of the Distribution Network; or

6.1.2 To avoid the risk of danger to persons, damage to property or interference with the regularity or efficiency of Delivery; or

6.1.3 To preserve and protect the proper working of the Distribution Network, and meeting the Distributor's obligations to Transpower or any other network owner through which the Distributor directly or indirectly takes a supply of electricity; or

6.1.4 For the Distributor's Load Management Service as specified in clause 7; or

6.1.5 If supply of electricity to a Network Supply Point is or will be reduced, impaired or interrupted; or

6.1.6 In the event of an occurrence of Force Majeure; or

6.1.7 To accommodate the Electricity Retailer in the event of an envisaged shortage of electricity; or

6.1.8 To allow the Electricity Retailer to inspect, effect alterations, maintain or repair any fittings owned by the Electricity Retailer or Connected Customer.

6.2 Unplanned Interruptions

In situations where the Distributor does not know of the need for the interruption in advance, such as:

6.2.1 Faults on the Distribution Network caused by equipment failure, accident, storm or similar event; or

6.2.2 Overloading arising from a capacity shortage in the Distribution Network or Transpower's Grid; or

6.2.3 Emergencies; or

6.2.4 As a condition of the transmission service from Transpower, for the automatic low frequency-initiated tripping of specified 11kV feeders in the event that the Transpower Network integrity is endangered. (The Electricity Retailer and Other Electricity Retailers are offered the opportunity to participate with the Distributor in the selection of the specified feeders and/or Connected Customers).

6.3 Where the Distributor interrupts Delivery pursuant to clause 6.1, the Distributor shall liaise with the Electricity Retailer to arrange for appropriate reasonable prior notice to be given to the Electricity Retailers Connected Customers of its planned intention to interrupt the Delivery and shall consult with the Electricity Retailer over the timing of the interruption to minimise inconvenience to the Electricity Retailer's Connected Customers. For routine planned interruptions, appropriate prior notice shall be four days.

6.4 Where the Distributor interrupts Delivery pursuant to clause 6.1.8 the Electricity Retailer shall be responsible for dealing with the Generators and Other Electricity Retailers and the Distributor shall use its best endeavours to co-operate with the Electricity Retailer and all Other Electricity Retailers who have electricity conveyed over the Network.

6.5 Where the Distributor interrupts Delivery pursuant to clause 6.2 and if at least all Connected Customers supplied either from a distribution transformer in a built-up area or from a circuit breaker in a non-built-up area are involved then as soon as is practicable, the Distributor shall report to the Electricity Retailer the area affected by and reasons for the interruption and its expected duration.

6.6 In all situations of interruptions, the Distributor shall use all reasonable endeavours to minimise the period of interruption.

6.7 If there is a capacity shortage in the Distribution Network or Transpower's Grid associated with an interruption which creates a difficulty in Delivery and/or the transmission over the Transpower Grid, the Distributor shall determine the priorities for maintaining and restoring Delivery. The Distributor shall not make any determination under this clause for the purposes of discriminating between the Electricity Retailer and other Electricity Retailers.

6.8 The Electricity Retailer shall forthwith advise the Distributor of any defect or interruption to the electricity supply or other Distribution Network abnormality known to the Electricity Retailer, as soon as practicable after receiving such knowledge. Where such advice was not initially in writing, the Electricity Retailer will within 2 Business Days follow up the initial advice with written advice to the Distributor.

7 LOAD MANAGEMENT SERVICES

7.1 The Charges as at the Date of Commencement are dependent on the Distributor's Load Management Service, current at the Date of Commencement being maintained. The Distributor shall continue to operate its current Load Management Service, until such time as a new basis

is agreed with the Electricity Retailer and Other Electricity Retailers, including, without limitation, for the following purposes:

7.1.1 To alleviate congestion on the Distribution Network and manage demand for electricity at Network Supply Points;

7.1.2 To seek to minimise the transmission charges from Transpower;

7.1.3 To reduce the Distribution Network load in the event of emergencies occurring on the Distribution Network or on Transpower's Grid;

7.2 The Distributor may extend the use of its current Remote Signalling Service or provide other Remote Signalling Services to the Electricity Retailer, at the Distributor's discretion.

SCHEDULE B – Performance Targets

B1 Network Performance:

B1.1 The Distributor shall use reasonable endeavours to:

B1.1.1 Maintain the voltage at Connections to within the range specified in clause 53 of the Electricity Regulations 1997. The Electricity Retailer acknowledges that maintenance of voltage within the tolerance range may depend in part on the maintenance of the power factor at Connected Customers Installations as set out in the Network Code.

B1.1.2 Ensure that the levels of harmonic voltages and currents passed into Connected Customers Installations conform with the Limitation of Harmonic Levels Notice 1993, Electrical Code of Practice 36, or any other notice in substitution thereof in so far as the harmonic disturbance results from problems arising from a cause within the control of the Distributor.

B1.1.3 Meet the reliability performance targets on a five yearly average basis as published in its approved statement of corporate intent.

B1.1.4 Total number of proven customer voltage complaints per year where non compliance with clause B1.1 is proven not to exceed 4 per 10,000 Connections.

B1.1.5 The Distributor shall on request provide the Electricity Retailer with reports on the Distributor's performance against the Distribution Network performance targets set out in clauses B1.1.3 and B1.1.4 of this Schedule.

B2 Response to Enquiries:

B2.1 The Distributor shall use reasonable endeavours to respond to the Electricity Retailer's enquiries as follows:

B2.1.1 Provide acknowledgement to the Electricity Retailer of an enquiry or complaint from the Electricity Retailer within 3 Business Days.

B2.1.2 Complete an investigation relating to such enquiry or complaint within 10 Business Days (where reasonably practicable to do so).

B2.1.3 Provide a report on the findings of an investigation within 5 Business Days of the completion of the investigation, if requested.

B2.1.4 Respond promptly to all telephone calls or messages regarding situations of emergencies such as broken wires, fire, vehicle accident or circumstances where life is at risk. The Distributor shall dispatch services, as necessary. The costs of attendance will be borne by the Distributor and such circumstances shall take priority over all other undertakings with respect to continuity of Delivery.

B3 Reporting Unplanned Interruptions to Delivery:

B3.1 Pursuant to clause 6.5, the Distributor shall use reasonable endeavours to report such interruptions to the Electricity Retailer to the following timetable. Such reporting shall be by a process which is agreed between the parties:

B3.1.1 Within 15 minutes of the Distributor being advised of the occurrence of an unplanned interruption, the Distributor shall advise the Electricity Retailer the time and date of the event and the location and/or the connections affected.

B3.1.2 As soon as the Distributor has reliable information, the Distributor shall advise the Electricity Retailer when restoration of Delivery is expected and the cause of the unplanned interruption.

B3.1.3 Clauses B3.1.1 and B3.1.2 shall also apply with respect to the operation of the Load Management Service.

B4 Fault Call Receipt and Field Service Dispatch

B4.1 In providing its Associated Service Fault Call Receipt and Field Service Dispatch, the Distributor shall use reasonable endeavours to:

B4.1.1 Immediately advise the caller of any information known to the Distributor regarding the event (Schedule C clause C1.2).

B4.1.2 Undertake an investigation and provide a report (if requested) pursuant to Schedule C clause C1.7 and as detailed in Schedule B clauses B2.1.2 and B2.1.3.

B4.1.3 Have a fault person go to the vicinity of the fault within one hour (urban area) and within two hours (rural area) where there is an unplanned interruption to Delivery to a Major Customer Connection.

B4.1.4 Dispatch a standby generator with capacity of up to 300kVA to a Major Customer Connection within 24 hours following an unplanned interruption to Delivery to the Major Customer Connection except in circumstances of storms or Force Majeure.

SCHEDULE C – Associated Services

C1 Fault Call Receipt and Field Service Dispatch

The Distributor shall provide a service to receive fault calls from Connected Customers and the Electricity Retailer and to dispatch operators, faults persons and repair crews, as appropriate.

Incoming information may be via telephone, facsimile, or other appropriate means. In providing this service, the Distributor shall:

C1.1 Receive incoming calls.

C1.2 Advise the caller of any information known to the Distributor regarding the event, including cause and expected duration.

C1.3 Advise the Electricity Retailer if at least all Connected Customers supplied either from a distribution transformer in a built-up area or from a circuit breaker in a non built up area are affected and provide information known to the Distributor regarding the event, including cause and expected duration.

C1.4 Advise the news media if a significant number of customers are affected by the event.

C1.5 Liaise with Transpower, if Transpower's plant is involved.

C1.6 Dispatch fault services, as required.

C1.7 Pursuant to clause 6.5, provide a written report to the Electricity Retailer after the event. This report will detail the cause (if known), time of occurrence and duration of the event, the number of Connected Customers affected and any measures taken to prevent recurrence. In situations where a significant number of Connected Customers are affected, the Electricity Retailer shall assist the Distributor by processing the calls from Connected Customers and providing the Distributor with filtered information.

C2 New Connections

The Distributor shall undertake all negotiations with the owners of future Connected Customer's Installations or their agents with respect to the establishment of new Connections. This will include settling a Connection Agreement with the party who is wanting to establish the new Connection. An Electricity Retailer may be the agent for a developer or future Connected Customer in negotiations with the Distributor. An Electricity Retailer shall become contractually involved when a supply of energy is required.

C3 Modification of an Existing Connection

The Distributor shall undertake all negotiations with the Connected Customers or their agents with respect to modifications to established Connections. This will include settling a Connection Agreement with the Connected Customer. The Electricity Retailer may be the agent for the Connected Customer. A modification could include, but is not limited to, an upgrading or downgrading of the capacity or a conversion from an overhead to an underground Connection.

C4 Temporary Isolations

The Distributor shall arrange for the temporary isolation of a Connected Customer's Installation in response to a request from the Connected Customer or the Electricity Retailer provided that where the request is from the Electricity Retailer, the Electricity Retailer shall indemnify the Distributor from all losses or costs arising from the Distributor's complying with the request, provided the Distributor acts in accordance with Good Industry Practice. The Distributor shall

charge the party requesting the new service as detailed in its *schedule of charges for associated services*.

C5 Provision of Ripple Signalling

Pursuant to clause 7, the Distributor shall provide ripple signals for its Load Management Service, as part of the Delivery Service.

C6 Power Quality Complaints and Issues

The Distributor shall receive and act upon all enquiries or complaints from Connected Customers or the Electricity Retailer regarding power quality. If investigations of any substance are required, then the Distributor shall refer the matter to a contractor. The Distributor will cover all expenses if the Distributor is at fault. Otherwise the enquiring party shall pay all expenses.

C7 Network Plant Removal or Re-siting

The Distributor shall deal with all enquiries from Connected Customers or the Electricity Retailer regarding requests for Distribution Network equipment removal or re-siting. The Distributor shall liaise with the enquiring party and negotiate the arrangements for the work to be executed. All costs of plant removal or re-siting shall be borne by the enquiring party.

C8 Emergency Calls

The Distributor shall respond urgently to all telephone calls or messages regarding situations of emergencies such as broken wires, fire, vehicle accident or circumstances where life is at risk. The Distributor shall dispatch services, as necessary. The costs of attendance will be borne by the Distributor and such circumstances shall take priority over all other undertakings with respect to continuity of Delivery.

C9 Advance Notice of Planned Interruptions

Prior to implementing a planned interruption per clause 6.1, the Distributor shall use reasonable endeavours to identify the Connections involved and despatch appropriate notices(s) as agreed with the Electricity Retailer. Such notice can be sent either directly to the occupant at the address of the connection or to the Electricity Retailer, as agreed.

C10 Use of Standby Generation for Load or Capacity Management

Where an interruption to Delivery is required or occurs which is initiated by the Distributor, the Distributor may use its standby generator(s) to minimise the incidence and duration of interruptions. This shall be solely at the Distributor's discretion.

C11 Maintenance on Connected Customer's side of Network Connection Point

The Distributor will, at its own cost, carry out repairs, maintenance and replacement of equipment such as lines, cables and poles necessary for the supply of electricity between the network connection point to the building entry point. This service covers fair wear and tear, including damage caused by storms, but not damage caused by the Connected Customer or any third party or the Connected Customer's failure to comply with the Electricity Retailer's terms and conditions of supply.

C12 Complaints Handling Service

The Distributor will provide an in-house consumer complaints service for handling Lines Complaints, as required in schedule D of the Electricity Complaints Commissioner Scheme. The Distributor shall deal with all Lines Complaints except those relating to issues covered in Schedule F of this Agreement where the Electricity Retailer and Distributor agree to the Electricity Retailer handling these directly, within the limits given in Schedule F.

C13 Temporary Connections

The Distributor will provide an agency and subcontracting service with respect to temporary connections that the Distributor provides, generally for building and construction sites. As an agent, the Distributor will vet applications on behalf of the Electricity Retailer. As a subcontractor, the Distributor will provide administration and information, process applications, provide the temporary connection, and provide a boundary box (if required).

SCHEDULE D – Discretionary Services

D1 Provision of Additional Ripple Signals

The Distributor will negotiate with the Electricity Retailer to provide additional ripple signals over and above those that are already established for the Load Management Service. The Distributor shall use its best endeavours to provide these as required by the Electricity Retailer, subject to the availability of time slots and the limitations of the Distributor's ripple injection plants. Signals required for the Load Management Service shall have priority and all additional signals provided for the Electricity Retailer shall be chargeable.

D2 Use of Standby Generator for Energy Shortage

The Distributor may make its standby generator(s) available to the Electricity Retailer or Connected Customers for use in situations of energy shortage, subject to the Distributor's requirements as set out in clause C10 taking priority. The Distributor shall charge the party requiring this service.

D3 Temporary Connections

The Distributor may provide temporary boundary boxes to facilitate construction at temporary connections.

SCHEDULE F -Non-Performance Payments Schedule (with reference to Clause 5.6)

F1 Restoration of Electricity Delivery

(a) In an urban area the desired target time to restore electricity delivery is within 1.5 hours. Subject to clause F4 if the Distributor does not have electricity restored within three hours of being notified of the fault the Distributor will pay \$25.00 (GST inclusive) per Connection based on verified claims received from Electricity Retailers.

(b) In a rural area the desired target time to restore electricity delivery is within three hours. Subject to clause F4 if the Distributor does not have electricity restored within six hours of being

notified of the fault the Distributor will pay \$25.00 (GST inclusive) per connection based on verified claims received from Electricity Retailers.

(c) In the case of natural disaster (such as, but not limited to snow storms, high winds, lightning, floods and earthquakes) the Distributor will use its best endeavours to restore electricity delivery as soon as practicable. In these circumstances no non-performance payments will be made.

(d) Faults caused by a third party e.g. such as Transpower, contractor damage, vehicle or machinery damage will not be subject to non-performance payments.

F2 Advance Notification of Planned Outage Affecting Delivery Service

(a) Where planned maintenance or network alterations (as per clause 6.1.1) need to be carried out and the Delivery Service is to be interrupted the Electricity Retailer will be given a minimum of four days notice of the Connections supplied by them affected by the outage or the occupant(s) of the connection(s) affected will be directly notified as agreed with the Electricity Retailer.

(b) If the Distributor fails to take these steps the non-performance payment for non-notification shall be \$15.00 (GST inclusive) per Connection based on each verified claim received from the Electricity Retailer.

F3 New First Time Connections to the Network

(a) Where existing network reticulation is available in a street including existing boundary connection boxes in underground areas, or road crossings, and existing poles in an overhead low voltage reticulated area, then new residential property Connections will be made by the Distributor within five Business Days of completion of all necessary Council, Telecom and other approvals.

(b) In all other cases, new Connections which require additional capacity to be provided or extensions to the network from the existing network, are subject to a design/build contract generally between the agent of or owner of the premises to be connected and an authorised contractor. The time taken for the connection will vary depending on size and location, and will be subject to an agreed time frame as specified in the design/build contract.

When the new asset is completed and is ready for service the final Connection process will be made by the Distributor within five Business Days, subject to receipt of all approvals and notifications required to carry out enlivenment.

(c) Where the Distributor fails to meet the time frame in part F3(a), a payment of \$25.00 (GST inclusive) in respect of each Connection, for each verified claim received from the Electricity Retailer, will be paid.

(d) Where the Distributor fails to meet the time frame in part F3(b), a payment of \$100.00 (GST inclusive) in respect of each Connection, for each verified claim by the Electricity Retailer, will be paid.

F4 Limitations on Application of Guarantees

(a) No obligation to make any payment under the non-performance payment obligations in this schedule shall arise where the failure to meet the standard was principally caused by an event beyond the direct control of the Distributor, or principally caused by the actions of a third party or the Electricity Retailer.

(b) The total liability of the Distributor under this non-performance payment schedule and all other identical non-performance payment schedules with Other Electricity Retailers, shall be included as part of the Distributor's maximum total liability stated in clause 19.5. Payments shall be apportioned by the Distributor acting reasonably.

Appendix 26

Detailed schedule of asset values

Closing RAB at FY12 by asset type

Closing FY12 RAB values by asset type	
Subtransmission network	(\$ million)
<i>Subtransmission</i>	
66 kV overhead lines (concrete pole)	0.3
66 kV overhead lines (wood pole)	5.9
66 kV overhead lines (steel tower and steel pole)	0.2
66 kV underground cables (PILC and Oil filled)	23.5
66 kV underground cables (XLPE)	9.8
33 kV overhead lines (concrete pole)	0.0
33 kV overhead lines (wood pole)	2.2
33 kV overhead lines (mixed construction)	7.4
33 kV underground cables (PILC)	1.1
33 kV underground cables (XLPE)	3.3
Pilot / communications circuits	4.1
<i>Zone substations (excl. switchgear)</i>	
Zone substation land	8.9
Zone substation site development and buildings	25.4
Power transformers	26.5
Protection	15.4
Outdoor structure (concrete pole)	3.7
DC Supplies, batteries and inverters	0.1
Other items	0.9
Total	138.6
Distribution network	(\$ million)
<i>Distribution lines and cables</i>	
11kV overhead lines (wood pole)	22.8
11kV overhead lines (mixed construction)	46.3
11kV underground cables (PILC)	90.0
11kV underground cables (XLPE)	63.0
<i>Distribution substations</i>	
Distribution substation land	27.2
Distribution transformers (pole)	23.4
Distribution transformers (pad)	44.8
Distribution substations (pole)	2.6
Distribution substations (pad)	9.0
Distribution substations (building)	1.1
Switchgear cabinets	0.3
Total	330.5

Switchgear	(\$ million)
66/33kV air break isolators & surge diverters	2.8
66/33/11kV indoor circuit breakers	36.0
66/33/11kV outdoor circuit breakers and switchgear	0.6
11kV disconnectors & dropout fuses	23.8
11kV voltage regulators	1.5
11kV circuit breaker/recloser & sectionalisers	2.4
11kV MSU and oil switches	34.4
Total	101.5
Low voltage distribution network	(\$ million)
LV overhead lines (wood pole)	21.4
LV overhead lines (mixed construction)	26.9
LV underground cables (PILC)	4.6
LV underground cables (XLPE)	141.3
LV customer service connections and link pillars	34.9
Total	229.0
Supporting or secondary systems	(\$ million)
Ripple injection	5.6
SCADA and communications, UHF masters and repeaters	10.4
Peak load generators	0.6
Easements	0.4
Network spares	4.9
Finance leases	5.6
Capital contributions	(10.3)
Total	17.1
Non system fixed assets	(\$ million)
Office Buildings	2.7
Information and Technology Systems	6.7
Office Furniture and Equipment	0.3
Tools, Plant and Machinery	1.8
Vehicles	2.1
Land	13.6
Total	27.4

Appendix 27

Construction cost benchmarks

Construction Cost Benchmarks

EDB Construction Cost Benchmarks				
Asset Category	Asset Description	2010 Orion Costs (\$000)	2010 Average EDB Costs (\$000)	Orion vs Average EDB Costs (%)
SUBTRANS - LINES	33 kV Lines . Heavy (? 150 mm2 , ? 300 mm2 Al)	73.3	76.8	-5%
SUBTRANS - LINES	33 kV Lines . DCct Heavy	108.5	137.4	-21%
SUBTRANS - CABLES	33 kV - Cables (? 240 mm2 Al)	137.1	360.8	-62%
SUBTRANS - CABLES	33 kV - Cables DCct (? 240 mm2 Al)	218.7	594.5	-63%
ZONE SUBS	33 kV Indoor Switchgear Cubicle	61.3	82.8	-26%
ZONE SUBS	22/11 kV Indoor Switchgear Cubicle	33.5	43.6	-23%
DIST LINES	11 kV O/H Medium (> 50 mm2 , < 150 mm2 Al)	51.2	54.3	-6%
DIST LINES	11 kV O/H DCct Medium	86.3	80.6	7%
DIST LINES	11 kV O/H Underbuilt Medium	31.0	31.4	-1%
DIST CABLES	11 kV U/G Medium(> 50 mm2 , ? 240 mm2 Al)	156.7	207.3	-24%
DIST CABLES	11 kV U/G DCct Medium	258.0	392.0	-34%
DIST SWGR	22/11 kV Disconnecter 3 ph (Excl Pole)	8.2	8.1	1%
DIST SWGR	22/11 kV Load Break Switch (Excl Pole)	8.6	10.1	-15%
DIST SWGR	22/11 kV Dropout Fuse 3 Ph (Excl Pole)	1.5	1.8	-20%
DIST SWGR	22/11 kV Sectionaliser (Excl Pole)	20.6	18.2	13%
DIST SWGR	22/11 kV Recloser (Excl Pole)	20.5	35.3	-42%
DIST SWGR	Ring Main Unit – 3 Way	26.9	30.6	-12%
DIST SWGR	Extra Oil Switch	4.2	13.5	-69%
DIST SWGR	Extra Fuse Switch	4.2	16.4	-74%
DIST TX - 1PH -11kV POLE	Up to and including 15 kVA	2.6	2.7	-1%
DIST TX - 1PH -11kV POLE	30 kVA	3.1	3.5	-12%
DIST TX - 1PH -11kV POLE	75 kVA	7.2	7.1	1%
DIST TX - 3PH - 11kV POLE	Up to and including 30 kVA	4.3	4.5	-4%
DIST TX - 3PH - 11kV POLE	50 kVA	4.9	5.7	-13%
DIST TX - 3PH - 11kV POLE	100 kVA	7.8	8.5	-8%
DIST TX - 3PH - 11kV POLE	200 kVA	11.6	12.4	-7%
DIST TX - 3PH - 11kV GRND	100 kVA	9.8	12.4	-21%
DIST TX - 3PH - 11kV GRND	200 kVA	13.2	15.7	-16%
DIST TX - 3PH - 11kV GRND	300 kVA	18.2	20.7	-12%
DIST TX - 3PH - 11kV GRND	500 kVA	22.2	26.9	-17%
DIST TX - 3PH - 11kV GRND	750 kVA	29.1	33.9	-14%
DIST TX - 3PH - 11kV GRND	1,000 kVA	34.9	39.4	-11%
DIST TX - 3PH - 11kV GRND	1,500 kVA	48.4	57.8	-16%
DIST SUB - POLE	Pole Mounted (50 kVA or less)	2.3	4.9	-53%
DIST SUB - POLE	Pole Mounted (100 kVA or more)	4.4	7.6	-42%
DIST SUB - GRND	Ground Mounted (Covered)	29.5	17.7	67%
DIST SUB - GRND	Kiosk (Masonry or block enclosure)	28.3	39.7	-29%

EDB Construction Cost Benchmarks

Asset Category	Asset Description	2010 Orion Costs (\$000)	2010 Average EDB Costs (\$000)	Orion vs Average EDB Costs (%)
LV LINES	Overhead Medium 4 wire LV only (> 50 mm2, ? 150 mm2 Al)	137.1	112.7	22%
LV LINES	Overhead Medium 2 wire LV only (> 50 mm2, ? 150 mm2 Al)	94.0	98.0	-4%
LV LINES	Overhead Medium Underbuilt 2 wire (> 50 mm2, ? 150 mm2 Al)	45.4	45.3	0%
LV LINES	Overhead Light Underbuilt 2 wire (? 50 mm2) Al	30.6	39.5	-23%
LV CABLES	Underground Medium - LV Only (? 240 mm2)	155.0	148.0	5%
LV CABLES	Underground Medium - with HV (? 240 mm2)	103.0	119.0	-13%
LV CABLES	2 way Link Pillar	3.5	3.5	0%
LV CABLES	4 way link pillar	4.9	7.0	-30%
CUST SERVICE CONN	LV overhead - 1 ph	0.2	0.8	-70%
CUST SERVICE CONN	LV overhead - 3 ph	0.4	1.1	-67%
CUST SERVICE CONN	LV underground - 1 ph shared fuse pillar	1.3	1.7	-21%
CUST SERVICE CONN	LV underground - 1 ph Own fuse pillar	1.3	1.7	-23%
CUST SERVICE CONN	LV underground - 3 ph shared fuse pillar	1.7	2.0	-18%
CUST SERVICE CONN	LV underground - 3 ph Own fuse pillar	1.6	1.9	-18%

Appendix 28

EDB opex benchmarks

Support opex benchmarks

Comparisons with like EDBs show that our support opex costs compare well. On a cost per ICP basis, general management, administration and overhead costs fall well below the peer group median in FY10 and FY11 and are considerably less than the industry average in both years. Our system management and operations costs fall within the third quartile of the peer group and are similar to the industry average in both years, as illustrated below.

General Management, Administration and Overheads plus System Management and Operations (\$/ICP)			General Management, Administration and Overheads plus System Management and Operations (\$/ICP)		
Rank		FY10	Rank		FY11
1	Unison Networks	147.2	1	Unison Networks	181.8
2	Wellington Electricity Lines	110.1	2	Wellington Electricity Lines	119.3
3	WEL Networks	108.9	3	Aurora Energy	113.6
4	Aurora Energy	103.3	4	WEL Networks	104.6
5	Orion New Zealand	102.4	5	Orion New Zealand	103.5
6	Powerco	100.8	6	Powerco	89.0
7	Vector	75.7	7	Vector	87.2
	Industry Average	151.8		Industry Average	166.6
	Industry Median	147.2		Industry Median	151.6
	Peer Group First Quartile	101.6		Peer Group First Quartile	96.2
	Peer Group Median	103.3		Peer Group Median	104.6
	Peer Group Third Quartile	109.5		Peer Group Third Quartile	116.4

General Management, Administration and Overheads (\$/ICP)			General Management, Administration and Overheads (\$/ICP)		
Rank		FY10	Rank		FY11
1	Unison Networks	114.7	1	Unison Networks	141.1
2	Powerco	81.7	2	Vector	79.8
3	Vector	71.7	3	Powerco	67.8
4	WEL Networks	71.4	4	WEL Networks	63.7
5	Orion New Zealand	51.6	5	Aurora Energy	54.1
6	Aurora Energy	44.0	6	Orion New Zealand	51.1
7	Wellington Electricity Lines	22.2	7	Wellington Electricity Lines	29.1
	Industry Average	101.7		Industry Average	114.3
	Industry Median	86.4		Industry Median	102.9
	Peer Group First Quartile	47.8		Peer Group First Quartile	52.6
	Peer Group Median	71.4		Peer Group Median	63.7
	Peer Group Third Quartile	76.7		Peer Group Third Quartile	73.8

System Management and Operations (\$/ICP)			System Management and Operations (\$/ICP)		
Rank		FY10	Rank		FY11
1	Wellington Electricity Lines	87.9	1	Wellington Electricity Lines	90.2
2	Aurora Energy	59.3	2	Aurora Energy	59.6
3	Orion New Zealand	50.8	3	Orion New Zealand	52.4
4	WEL Networks	37.5	4	WEL Networks	41.0
5	Unison Networks	32.4	5	Unison Networks	40.7
6	Powerco	19.1	6	Powerco	21.2
7	Vector	4.0	7	Vector	7.3
	Industry Average	50.1		Industry Average	52.3
	Industry Median	48.0		Industry Median	48.7
	Peer Group First Quartile	25.8		Peer Group First Quartile	30.9
	Peer Group Median	37.5		Peer Group Median	41.0
	Peer Group Third Quartile	55.1		Peer Group Third Quartile	56.0

There is some discrepancy in the allocations between these two support opex categories (which are prepared for ID purposes). Accordingly it is also appropriate to consider total support costs, which removes the influences of different approaches to allocating costs between the sub categories. When considering total corporate and network support costs, our costs on an ICP basis are less than the peer group median in FY10 and FY11 and considerably less than the industry average.

We note that we have excluded from this analysis, the \$1.5m of extraordinary earthquake overhead costs incurred in FY11.

We also note that FY12 data was not available at the time this analysis was prepared (as FY12 ID disclosures were deferred until the end of calendar year 2012).

Peer Group Statistics

For the purpose of assessing relative performance, we have selected our peer group on the basis of the following indicators:

- total size of the network (indicated by the total number of customer connections served)
- network density (indicated by the ratio of customer connections per circuit kilometre).

As there are significant scale differences in New Zealand, and as we fall towards the upper end of the scale spectrum, we have chosen to include total connections in our peer grouping approach. In our view this is reasonable because the smallest networks are considerably smaller than Orion and we would not expect similar scale influences for those networks.

In addition there is a considerable range of network densities (ICPs/km) across EDBs. As the underlying characteristics of predominantly urban networks differ to predominantly rural networks we have also used this criterion for our peer group selection.

ICPs			ICPs		
Rank		FY10	Rank		FY11
1	Vector	527,096	1	Vector	531,185
2	Powerco	317,489	2	Powerco	319,181
3	Orion New Zealand	192,179	3	Orion New Zealand	193,234
4	Wellington Electricity Lines	164,058	4	Wellington Electricity Lines	164,250
5	Unison Networks	108,212	5	Unison Networks	108,978
6	WEL Networks	84,276	6	WEL Networks	83,614
7	Aurora Energy	81,573	7	Aurora Energy	82,368
	Industry Average	68,862		Industry Average	69,301
	Industry Median	30,615		Industry Median	30,826
	Peer Group First Quartile	96,244		Peer Group First Quartile	96,296
	Peer Group Median	164,058		Peer Group Median	164,250
	Peer Group Third Quartile	254,834		Peer Group Third Quartile	256,208

ICPs/km			ICPs/km		
Rank		FY10	Rank		FY11
1	Wellington Electricity Lines	35.6	1	Wellington Electricity Lines	35.7
2	Vector	29.9	2	Vector	30.0
3	Orion New Zealand	17.9	3	Orion New Zealand	17.9
4	WEL Networks	16.7	4	WEL Networks	16.5
5	Aurora Energy	14.6	5	Aurora Energy	14.7
6	Unison Networks	11.3	6	Unison Networks	13.7
7	Powerco	10.6	7	Powerco	10.7
	Industry Average	12.3		Industry Average	12.4
	Industry Median	9.2		Industry Median	9.3
	Peer Group First Quartile	12.9		Peer Group First Quartile	14.2
	Peer Group Median	16.7		Peer Group Median	16.5
	Peer Group Third Quartile	23.9		Peer Group Third Quartile	24.0

As demonstrated above, Vector and Powerco are considerably larger than Orion, although they fall on either side on a connection density basis. The other networks included in the peer group are smaller (Wellington Electricity being the closest in size) and, with the exception of Wellington Electricity, have similar connection densities. The industry average for total connections (approximately 69,000) is considerably less than Orion. The industry average connection density (approximately 12 ICPs/km) is also considerably less than Orion.

Appendix 29

Network security gaps

Network security gaps

The network gaps identified in the following tables 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.

Transpower GXPs

The Electricity Participation Code includes a national transmission grid reliability standard. This standard states that Transpower is required to maintain an N-1 level of security for the core grid. The GXP gaps identified below are based on the application of our security standard to the Transpower core-grid, spur or GXP assets. Proposed projects for Transpower core grid assets will be subject to Commission approval.

The tables include current security standard gaps only. Additional projects listed in the ten year AMP provide solutions for future forecast gaps that are not stated here.

Several projects address more than one security gap and are therefore quoted in more than one location. Transpower meets the initial capital cost and then charges us an annualised amount for the use of the additional assets. Transpower costs are essentially passed through to us to be recovered from our consumers. Transpower project costs are estimates only.

Transpower GXP security gaps							
Network gap	VOLL per event \$000	VOLL p.a. \$000	Solution	Cost \$000 (real terms)	Cost p.a. \$000	Benefit cost ratio	Proposed date
Addington							
Single Addington No.2 11kV GXP busbar fault causing complete loss of supply to 23MW of load. Restoration achievable in 2hrs.	534	8.0	Install bus zone protection to create two bus zones as part of the planned 11kV switchgear replacement.	Orion 27	2.9	2.8:1	2015 during switchboard replacement and following Orion purchase of the assets
Bromley and Islington							
Bromley 220/66kV transformer failure causing cascade trip during high loads.	2,100	20	Upgrade Bromley interconnectors.	TP 8,410	925	1:46	Contract signed with Transpower to complete work by March 2013

Partial loss of restoration for an Islington 220/66kV dual transformer failure.	8,200	30	Upgrade Bromley interconnectors.	TP 8,410	925	1:31	Contract signed with Transpower to complete work by March 2013
Islington							
Partial loss of restoration for an Islington 220/33kV dual transformer failure.	2,200	4	Templeton 66kV substation. (1)	Orion 4,485	646	1:162	Influenced by load growth at Wigram and Templeton.
Hororata							
Interruption to all Hororata GXP load for a 66kV bus fault (restorable).	830	19	Install a 66kV bus coupler (75% of load will remain on).	TP 500	55	1:2.9	Uneconomic. No date proposed. The planned 66kV links from Highfield to Greendale and Darfield will significantly reduce the interrupted load.
Partial loss of restoration for a Hororata 66/33kV dual transformer failure.	1,180	11	Convert Hororata to 66kV. (1)	Orion 1,527	168	1:15.3	Hororata conversion year ending 31 March 2018.
Interruption to all Hororata 33kV GXP load for a 33kV bus fault (restorable).	TBA	TBA	Install a 33kV bus coupler (will halve VOLL values).	TP 250	28	TBA	Uneconomic. No date proposed. The Hororata 33kV switchboard is due for replacement by 2020 and is proposed to simply 33kV connections and negate the need for a 33kV busbar.
Springston							
Partial loss of restoration for a Springston 66kV dual line or 66/33kV	TBA	TBA	Larcomb 66kV.	TBA	TBA	TBA	Year ending 31 March 2014.

transformer failure.							
Interruption to all Springston 33kV GXP load for a 33kV bus fault (restorable).	907	21	Install a 33kV bus coupler (will halve VOLL values).	TP 250	28	1:1.3	It is envisaged that the staged conversion of the substations on Springston 33kV to 66kV will result in an exit from all 33kV at Springston by 2025, making the proposed solution uneconomic. Banks Peninsula 33kV sites will be fed from 66kV to 33kV transformers at Motukurara in the future.

Orion security gaps

Substation	Network gap	Solution	Cost \$000	Proposed date
Dallington	Single 66kV supply to Dallington zone substation due to the February 2011 earthquake. Loss of 30MW of load for a single 66kV line or transformer failure. Restoration achievable in 5min.	Complete a 66kV loop from Rawhiti via proposed Marshlands site by installing a new cable from Marshlands to McFaddens zone substation.	6,112	2020
	Single Dallington 11kV busbar fault causing complete loss of supply to 33MW of load. Restoration achievable in 2hrs.	Install bus zone protection to create two bus zones as part of the planned 11kV switchgear replacement.	27.5	2019
Halswell	Single Halswell 66kV busbar fault causing complete loss of supply to 42MW of load.	Installation of a bus coupler at this stage is uneconomic. In the longer term the Halswell 66kV bus arrangements will need to change to a ring bus to accommodate other changes.	TBA	TBA
Heathcote	Single Heathcote 11kV busbar fault causing complete loss of supply to 21MW of load. Restoration achievable in 2hrs.	Install bus zone protection to create two bus zones as part of the planned 11kV switchgear replacement.	25	2019
Hoon Hay	Single Hoon Hay 11kV busbar fault causing complete loss of supply to 28MW of load. Restoration achievable in 2hrs.	Install bus zone protection to create two bus zones as part of the planned 11kV switchgear replacement.	25	2026
Lancaster	Loss of 18MW of load for a single 66kV cable failure. Restoration achievable in 5min.	Complete a 66kV loop from Hoon Hay to Milton.	8,329	2025
Moffett	Single Moffett St 11kV busbar fault causing complete loss of supply to 18MW of load. Restoration achievable in 2hrs.	Install bus zone protection to create two bus zones as part of the planned 11kV switchgear replacement.	50	2030
Papanui	Interruption to all Papanui load for a 66kV bus fault (restorable).	Our northern subtransmission plan will provide an opportunity to operate the Papanui 66kV bus with a permanent split.	NA	2020

	Single busbar fault at Northcote Rd No.123 network substation on the Belfast 11kV ring causing a cascading loss of supply to 24MW of load. Restoration achievable in 2hrs.	Uneconomic to install an 11kV bus coupler at Northcote Rd No.123. The impact will be reduced by the installation of Marshland zone substation (project 488) and then fully solved by reconfiguring Northcote Rd No.123.	NA	NA
Rawhiti	Single 66kV supply to Rawhiti zone substation due to the February 2011 earthquake.	Install new cable from Hawthornden zone substation via proposed Waimakariri and Marshlands sites (these projects require a further \$12m which delivers shared benefits for Rawhiti).	18,141	2016
Bishopdale	Single Bishopdale 11kV busbar fault causing cascading loss of supply to 22MW of load. Restoration achievable in 2hrs.	This security gap will be resolved as part of scheduled switchgear replacement at Bishopdale.	25	2016

Appendix 30

Letter from CCC on undergrounding

Office of the Chief Executive

14 December 2012

Rob Jamieson
Chief Executive
Orion
P O Box 13896
Christchurch

Dear Rob

Orion's Post Earthquake Pricing and Reliability

Thank you for your recent presentation on Orion's proposals to restore the reliability and resilience of the city's power supply. One of the Council's draft community outcomes for its 2013-2022 Long-term Plan is that "Christchurch's infrastructure supports sustainable economic growth". A reliable and resilient electricity network clearly contributes to the achievement of this outcome.

I understand that David Freeman-Greene and John O'Donnell have since met with staff from the Council's Strategy and Planning Group to seek clarification of the Council's policy on the undergrounding of new power cables. The Christchurch City Plan includes a policy (8.3.2) that promotes the undergrounding of power cables, particularly within the urban areas of the city and the Port Hills. The policy recognises that overhead lines detract from visual amenity, although it also acknowledges that economic considerations should be taken into account.

The City Plan went through a 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 in community views on this matter. However, I note that Orion is seeking public comment on its proposed application to the Commerce Commission and that the Commerce Commission will itself undertake further consultation in 2013. We would be very interested in the outcomes of this consultation.

Please feel free to contact me or Alan Bywater, Strategic Policy Unit Manager, if you require any further information.

Yours sincerely


Tony Marryatt
Chief Executive

Appendix 31

Emergency maintenance contract terms
(extract)

Emergency Maintenance Contract Terms (extract)

1. SCOPE OF WORKS

The contract shall serve as the governing document that will form the general terms and conditions for all Orion works ordered.

Works will include Emergency Work, Planned/Scheduled Work, Minor Works and third party/customer driven work associated with connecting to the Orion electricity distribution network.

The contractor is to provide for a full emergency works response within the High Country and Plains area and a partial (substation, communications, SCADA, ripple, HV cable first call and HV cable second call) emergency response service in the Banks Peninsula area.

Please note that the emergency response contractor for overhead reticulation and low voltage cable response in the Banks Peninsula area has a requirement to directly engage Connetics as Orion's Nominated Subcontractor for the balance of the works that the contractor is not authorised by Orion to respond to.

The requirement for the Nominated Subcontractor status will be reviewed annually by Orion, work costs incurred under this requirement will be invoiced to Orion directly. Initial response and work completion requirements shall be met as if directed by Orion.

2. CONTRACT TERM

This is a three year contract and will terminate on the anniversary unless other agreements between the Principal and contractor have been secured.

A two year extension may be offered to roll over the contract term, however this will be dependent on the contractor's overall performance of the contract and is subject to the agreed performance targets being met. It is also at the sole discretion of Orion.

3. PREPARATION

The tender submission shall provide relevant evidence and information to demonstrate that the contractor and subcontractors under their control have sufficient experience, skills and resources to fulfil the terms and conditions of the contract and are positioned to meet the specific contract objectives.

The provisions of all relevant statutes, regulations and bylaws of government, local and other public authorities must be complied with. If these are not contained in the contract documents, it is the contractor's responsibility to check with the appropriate bodies to their requirements/standards.

The contractor must search out any records, locate and protect all utility services and landowner property that may be affected by the work being carried out.

4. GENERAL DESCRIPTION OF WORKS ORDERED

4.1 GENERAL

Orion (the Principal) chooses a selective tender process to determine what contractor's will be invited to undertake works ordered, there is no obligation on Orion to award any works to the contractor.

All works ordered under this contract are currently assessed as associated with the overhead reticulation, underground reticulation, substation assets, communication, SCADA and ripple assets within the Orion electricity distribution network area for the term of this contract.

Any work not associated with these particular assets is prohibited and not covered in this contract. The contractor will need to have in place a variation to this contract or other specific agreements with Orion in order for the work to be undertaken.

4.2 EMERGENCY WORKS

These are works of an urgent nature and repairs are to be undertaken immediately in conjunction with NW72.20.03.

The emergency works component of this contract requires that a live line response is available Monday to Friday 7.30am to 4.00pm only, outside these hours a live line response can be provided if practical.

4.3 PLANNED/SCHEDULED AND MINOR WORKS REQUESTED BY ORION

Work will be issued on a job by job basis as per the contractors quoted/tendered price or schedule of rates within the contract.

4.4 CUSTOMER DRIVEN WORK REQUESTED BY THIRD PARTY

This will be processed as outlined in NW70.10.03 and in conjunction with the connections and extensions policy. These works will be issued on a job by job basis as per the contractor's quoted/tendered price or schedule of rates within the contract.

Any identified proposed work or design configurations that may impact adversely on the Orion network or third parties that are within the public domain will be reviewed by Orion. Orion has the sole discretion to take over the management of such work if required. This includes any quotations submitted for work requests, Orion will manage the selection of tenders with which the commercial/financial negotiations may be conducted and ensure that they are commercially advantageous. If this is the case and once agreed to by Orion, the contractor will be compensated for their justified associated costs.

4.5 COMPETITIVE PRICING

To achieve the best value for its contracted works Orion intends to procure competitive prices for goods and services associated with the overhead reticulation, underground reticulation, substation assets, communication, SCADA and ripple assets, having due regard to the long term network security and work quality.

All works ordered by Orion where they are liable for payment, with a value in excess of \$5000 will be assessed by Orion, to ensure that the most cost effective options have been explored and that a competitive price process has been followed.

All work with a value in excess of \$20,000 is to be performed as a separate tendered contract. The lowest overall price shall be the accepted/awarded price provided the

contractor conforms to the evaluation criteria. Otherwise the remaining assessed prices may be accepted, provided they conform to the evaluation criteria.

Generally the most cost effective options are expected to be explored and that a competitive price process has been followed before any Orion work orders or individual customer connection agreements are issued.

5. CONTRACTOR PERFORMANCE

5.1 GENERAL

The contractor is responsible for providing the overall management, infrastructure, system support services and appropriate resources (competent persons, adequate materials and plant) required to undertake the services specified in this contract, meeting all standards and specifications referenced in but not limited to the information as included in the contract, including all physical aspects.

The contract requires the contractor to accept and manage all risks associated with the contract that indemnifies the Principal against any claim arising on account of but not limited to injury to persons or damage to property.

The contractor shall have in place or are already in a development stage of an integrated auditable Contract Management System that fundamentally meets the contracts Quality Assurance, Safety and Environmental requirements.

The contract requires the contractor to carry out internal audits on a regular basis, including a periodical formal audit of the contractor's Management System by an independent party. The results of such audits shall be made available to Orion on request.

5.2 PERFORMANCE REVIEW

Contractor performance will be monitored through the duration of the contract and will be formally reviewed 6 months prior to the three year contract completion date, the criteria may be re-established at the ongoing reviews as necessary.

1 6. CLAIMS AND PAYMENTS

6.1 GENERAL

The contractor's claims should be presented to Orion for assessment. These shall clearly identify the contract works that the claim relates to and if required shall be supported by an informative description that is sufficient to understand the work done and to justify the claims being made.

No payments will be made until satisfactory information has been received by Orion.

Any subcontractor invoices will be submitted to the head contractor for processing to the Principal/Orion.

Regarding emergency works response claims (refer NW72.20.03 section 3.10), these will be by way of a weekly invoice supported by the individual job information entered in the On-line Works Management Application.

6.2 CONTRACTOR ENGINEERING SUPPORT

Contractor engineering support is considered as additional resources needed where required to assist the contractor in performing their general duties under the contract, which may be due to unforeseen circumstances or unexpected escalations.

Where engineering support is claimed against the contract it must be justified and the contractor is to detail the types of tasks/services that are provided by their company with regards to the use of engineering support in their tender submission.

Engineering support claims should not be what would be expected as general administrative duties or support as per the fixed costs and management/supervision components within the contract.

6.3 CONTRACT SCHEDULES

The contractor is to prepare and submit all of the associated schedules of rates that will be used to manage the contractor's claims and variations for the Orion works ordered under this contract.

The schedules shall typically include all day rates, fixed rates, generic tasks rates and be geographically aligned i.e. metropolitan or rural. Overall the schedules shall demonstrate and identify any risks and exposure to the contractor and Orion.

2 7. INITIATIVES

Continuous improvement of contractor performance is required to provide a means of measuring against particular legislative and/or Orion standards.

Customer service is about satisfied customers. To that end, customer interactions and service levels need to be maintained and improved where possible. Any records of private agreements shall be kept and if required will assist in minimizing disputes between the customer and contractor should they arise.

Where the contractor, is seeking approval to implement a new initiative, they must present this to the Engineers representative for consideration, including a brief report outlining benefits, risks and any mitigation if required.

3 8. STAFF DEVELOPMENT REQUIREMENTS

Staff should be trained in accordance with all industry and employer standards and also need to be exposed to emergency works and associated procedures and processes to become familiar with all facets of work to be undertaken. The overall objective is an outcome that the staff and trainees gain experience and understanding to assist in achieving the expected competencies in their particular discipline.

The overall outcome is to provide additional resource competent to carry out this contract. Any individual staff/trainee record shall be kept to show traceability.

4 9. SPECIALIST SERVICES

Orion will provide training for proprietary equipment and systems at cost. Contractors should identify their training needs to Orion by late November each year for inclusion in the following year's budget.

It is expected that training requirements for specialist skills are clearly identified and a report submitted on a six monthly basis indicating completion of training.

The contractor shall maintain access to competent personnel, tools and equipment to fulfil fault response to the following specialist technical services:

1. 66kV and 33kV Cable Jointing – refer to 66kV and 33kV Cable Repair Contingency Plan NW72.12.02
2. Cable Fault Location
3. Fault Diagnostic Equipment for HV primary equipment (i.e. transformers, switchgear and associated protection)
4. SCADA, Electrical Network Communications and Ripple systems

Please detail within your tender submission your company's process for maintaining competent staff to deliver this service and justify any fixed costs associated with the provision of this service.

5 10. MAJOR EMERGENCY RESPONSE

A major emergency is an event beyond the normal emergency; it could be described as a one in three year event that requires additional support systems and resource to restore supply.

In the event of a major emergency situation, to assist the contractor with transitioning from a 'normal' emergency works response to a major emergency response, Orion's Network Asset Manager, Operations Manager, Engineer to the Contract or his Representative will direct this transition to the contractor, including any requirements or direction pertaining to the specific event.

When assisting in a major emergency response situation, the contractor is to use all existing systems and processes that would be used in 'normal' fault response work so that organizations are able to respond appropriately and reliably when faced with sudden and potentially catastrophic natural or technological emergencies.

Fundamental to this is the contractor's own emergency preparedness plan and contingencies to protect any intellectual property, information and communication systems to maintain a coordinated response with all stakeholders during the event.

Our requirement is that a copy of the contractor's emergency preparedness plan and the implementation process of the Emergency Response Management Information Systems (ERMIS) are available for assessment.

All schedules of vehicles, plant, equipment and human resources that would be available in a major emergency shall also be submitted.

Orion has in place an Electricity Supply Mutual Aid Agreement with various Network Operators which allows Orion to request further assistance under major emergency situations. This is a reciprocal arrangement and Orion may request you to assist other Network Operators under this agreement.

In the event of a perceived major emergency situation you should contact Orion prior to committing your resources to any other network operator.

Contractors would be expected to be available within 4 hours of a call and generally work would be expected to be performed during the hours of daylight.

Orion is to be notified of any changes to the list of available vehicles, plant, equipment and human resources in order to be current at all times.

Appendix 32

Contract procedures and policies

1. NW73.00.01 Standard contract document
2. NW73.00.02 Standard contract procedures
3. NW73.00.03 Contract management policy
4. NW73.10.07 Contract administration
5. NW73.10.09 Contract tendering
6. NW73.10.13 Evaluation of tenders
7. NW73.10.15 Authorised contractors
8. NW73.10.16 Post contract evaluation
9. OR00.00.19 Procurement policy

NETWORK ASSET MANAGEMENT

**STANDARD CONTRACT
DOCUMENT**

**NETWORK
POLICY STANDARD
NW73.00.01**

DISTRIBUTION REGISTER

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2.	Asset Manager
3.	Contract & Information Manager
4.	Contract Administrator
5.	Engineering Manager Electricity
6.	Engineering Manager Gas
7.	Contractors
8.	
9.	
10.	

STANDARD CONTRACT DOCUMENT

Responsibility

Notes

Contract
Administration

Standard Contract 3910
Schedule to conditions of tendering
Special Conditions
Preliminary & General

Specific to contract

Engineering
Management

Standard Specification
Scheduled Work NW 72 20 01
Non Scheduled Work NW 72 20 02

General
Specification

Engineering
Management

Standard Asset Specification
Technical specification NW__ __ __
or Technical Description

Specification
Specific
To Asset

Engineering
Management

Specific Technical Specifications
including Drawings, Major Materials Lists,
Schedule of work and Pricing schedules

Detail Specific to
Project to be
Performed

NETWORK ASSET MANAGEMENT

**STANDARD CONTRACT
PROCEDURE**

**NETWORK
PROCEDURE STANDARD
NW73.00.02**

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AMENDMENT RECORD

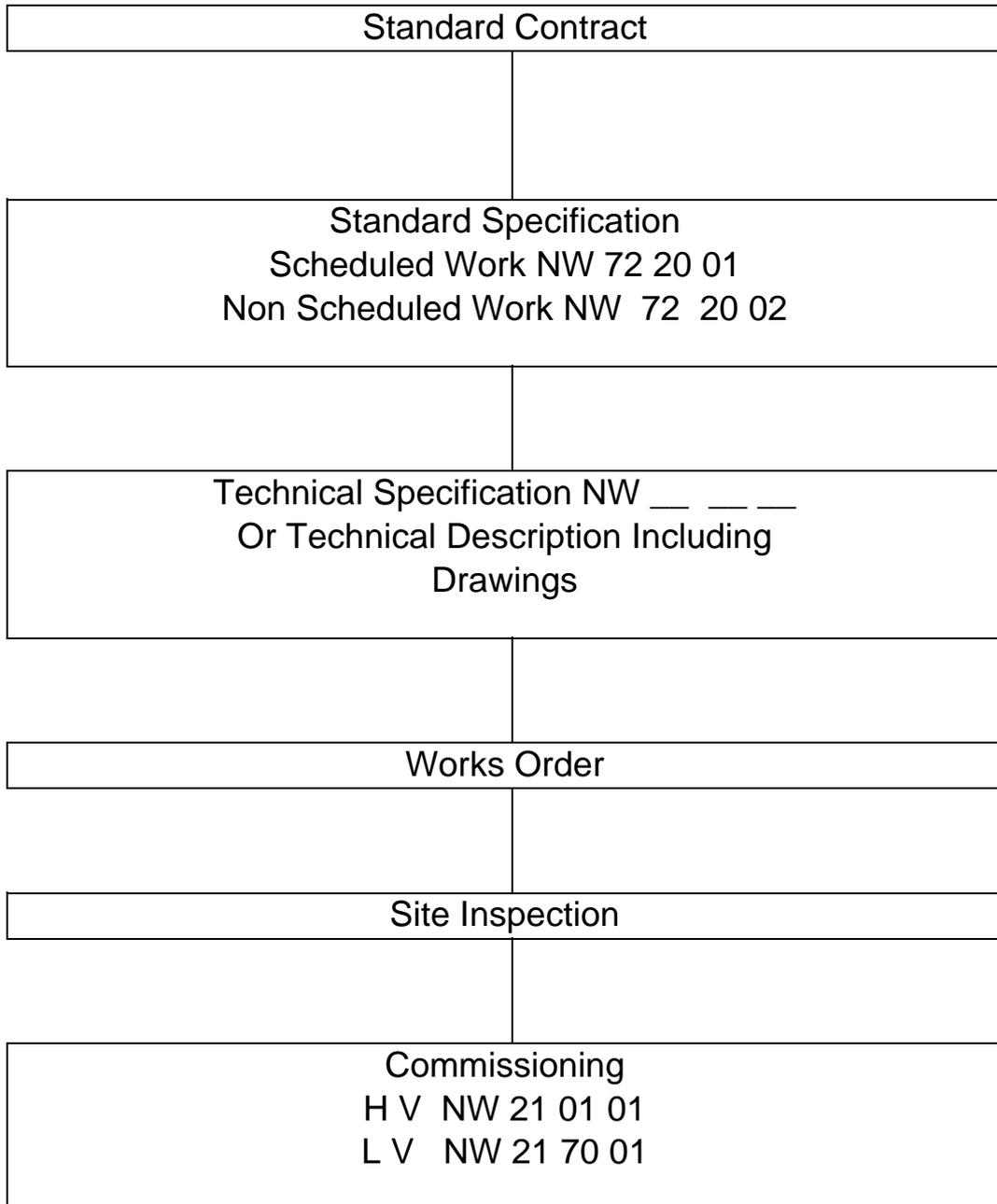
Amendment No.	Page Amended	Amend Date	Date Inserted	Inserted by	Approved by

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STANDARD CONTRACT PROCEDURE



NETWORK ASSET MANAGEMENT

**CONTRACT MANAGEMENT
POLICY**

**NETWORK
POLICY STANDARD
NW73.00.03**

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CONTRACT MANAGEMENT POLICY

Orion wishes to develop, promote and retain a group of competent contractors.

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 exceptions to the above are as follows:

- Emergency Works & Major Emergency Works which may be subject to a negotiated arrangement between the parties including a fixed payment to secure adequate specialist resource.
- Emergency spares and stock storage
- SCADA and ripple works (a specialist service)
- Metering (a specialist service)

Where there is only one supplier of goods and services a decision must be made on the basis of fair value for money. It will be necessary to make comparative judgements on fair value for money by comparing costs with the costs of similar goods and services.

In some cases it may be necessary to include lifetime costs to justify a decision. Other situations may require a solution which may be the best overall technical solution that can be justified for reasons such as reliability or technical compatibility.

It will be necessary for the person ordering the goods and services to state the reason for not accepting the lowest tendered price on document NW73.10.13 and attach this to the tender file.

These exceptions will require authorisation by the Asset Manager.

NETWORK ASSET MANAGEMENT

CONTRACT ADMINISTRATION

**NETWORK
PROCEDURE STANDARD
NW73.10.07**

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CONTRACT ADMINISTRATION

Please allow, when planning for any jobs, the following contract administration times (minimum) after completion of all design documents.

*	Prepare tender	1 working day
*	Await tender prices	10 working days
*	Tender evaluate tender against schedule (Design)	3-5 working days
*	Tender response	7 working days
*	Possession of site	7 working days

CONTRACT TENDERING

ELECTRICITY NETWORK

PROCEDURE

NW73.10.09

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Amendment No.	Page Amended	Amend Date	Date Inserted	Inserted by	Approved by
2	6, Orion	08.03.99			
3	4	09.05.00			
	9	19.07.04			

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TABLE OF CONTENTS

1. PREPARING DOCUMENTS	7
2. CALLING TENDERS.....	7
3. CLOSING TENDERS	7
4. TENDER EVALUATION.....	8
5. ACCEPTANCE OF TENDER	8
6. NOTIFICATION OF TENDER.....	8
APPENDIX A.....	9

1. PREPARING DOCUMENTS

Determine the type of work required:

- ◆ Design.
- ◆ Build.
- ◆ Design Build.

Determine whether a Design (Consultancy) type agreement, a Construction (NZS3910) or a Purchase (FIDIC) type agreement is required.

Prepare the Contract documents using the Contract Check List (NW 73.10.12) and confirming the following:

- ◆ Contract number.
- ◆ Contract title.
- ◆ Tender closing time, date and location.
- ◆ Required Design and Technical Specifications.
- ◆ Description of work.
- ◆ Start date.
- ◆ Duration or finish date.
- ◆ Any other Tender / Contract requirements.

2. CALLING TENDERS

Determine in conjunction with the Originator/Contract Manager which Contractors to invite to tender.

Prepare invitation letters; bundle with documents and post to Contractors.

Prepare "Notices To Tenderers" to clarify the documents in response to tenderers requests as required. All invited tenderers must receive clarification notices.

3. CLOSING TENDERS

Tenders closing in the Tender box are to be uplifted jointly by two officers using keys obtained from the Asset Management Office Administrator and the Ground Floor Receptionist.

Tenders shall be opened and the Tenderers names and offers recorded and signed by both officers. See Appendix A.

4. TENDER EVALUATION

Evaluate the tenders in conjunction with the originator of the work using the "Lowest Price Conforming Tender" method (NW73.10.13), consider any exceptions and deviations and obtain tender clarifications if required.

Notify both the successful and unsuccessful tenderers and advise the range of tendered prices.

5. ACCEPTANCE OF TENDER

The successful tenderer shall be notified as stated in the Conditions of Tender.

6. NOTIFICATION OF TENDER

The tenderers shall be notified as stated in the Conditions of Tender.

APPENDIX A**TENDER RECEIPT FORM****CONTRACT ____/____ E**

(E=Electricity)

TENDERS CLOSED 1:00PM _____ 200__

TENDERER	AMOUNT (EXCL GST)
Connetics	
Areva T&D	
Power Jointing	
Independent Line Services	
Line Maintenance Services	
Electrix	
Cherry Picker Specialists	
Treescape	
Southern Tree Maintenance	
Richdale Builders	
Kevin McGovern	
Other	

SIGNED: _____

DATE: _____

SIGNED: _____

DATE: _____

EVALUATION OF TENDERS

**NETWORK
POLICY STANDARD
NW73.10.13**

DISTRIBUTION REGISTER

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AMENDMENT RECORD

Amendment No.	Page Amended	Amend Date	Date Inserted	Inserted by	Approved by
2	Orion	08.03.99			
3	8	16.08.00			
4	6	27.03.03			

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EVALUATION OF TENDERS

LOWEST PRICE CONFORMING TENDER METHOD

Further to Clause 107.1 of the Schedule to the Conditions of Tendering the tender evaluation process shall be conducted in two stages as follows:

1. The first stage shall consist of determination of tender acceptability when assessed against each of seven non-price factors, and no others. Each factor shall be scored on a pass/fail basis. Any factor which scores a fail will exclude that tender from further consideration.
2. The second stage shall consist of the tendering authority determining which of the remaining conforming tenders has the lowest price.

Non-Price Factors

The seven non-price factors are:

Factor	Definition
1. Relevant Experience	The Tenderer's previous experience, particularly in technical areas relevant to the Specification.
2. Track Record	The Tenderer's record of completing projects to target, performance levels, on schedule, within budget and safely.
3. Competency and Technical Skills	The ability that the Tenderer's proposed personnel have with respect to the technical and legal requirement of the Specification. This includes appropriately trained, certificated and experienced persons for the class of work required to be done.
4. Adequacy of Safety Management Plan	The adequacy of the Tenderer's proposed Health and Safety Management Plan to meet the requirements of the HASIE Act, Electricity Act and Electricity Regulations, Resource Management Act, and all other statutory requirements.
5. Quality Assurance	The Tenderer must demonstrate developed procedures and programmes which provide quality control of work processes.
6. Customer Service	The tenderer must demonstrate a track record of commitment to the delivery of the expected specified Customer Service standards.
7. Management Skills	The ability within the Tenderer's organisation of people and systems appropriate to the successful management of the project.

**APPENDIX A:
Tender Assessment Check Sheet**

TENDER ASSESSMENT

CONTRACT NUMBER : _____

(Completed with reference to Tender Assessment Procedure
25/3/94)

Contractor Name: 1 _____ 2 _____ 3 _____ 4 _____

1) Relevant Experience	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>
2) Track Record	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>
3) Competency & Technical Skills	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>
4) Adequacy of Safety Management Plan	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>
5) Quality Assurance	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>
6) Customer Service	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>
7) Management Skills	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>
8) Price	<input type="text"/>	<input type="text"/>	<input type="text"/>	<input type="text"/>

The most suitable Contractor for the above contract is: _____

Their tendered price was \$ _____

Signed:

Engineer to Contract

NOTES: _____

**APPENDIX B:
Contract Tender Check List**



AUTHORISED CONTRACTORS

**INFRASTRUCTURE MANAGEMENT
ELECTRICITY NETWORK PROCEDURE
NW73.10.15**

DETAILS OF DOCUMENT AMENDMENT No.5	
Section amended	Description of amendment
Page 3	Contractor staff training.

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DEFINITIONS

Orion New Zealand Ltd ("Orion"): Is a Network management company with its head office based in Christchurch New Zealand.

Authorised Contractor: Is a contractor who is allowed access to work on Orion's network, such access may be limited as identified in Appendix B.

Invited Contractor: Is an Authorised Contractor who can be invited to carry out work for Orion.

SCOPE

Orion reserves the right to tender work to contractors as it sees necessary to minimise risk to the Orion business. Notwithstanding this Orion will limit contractors working on certain work to ensure a viable market for the remaining contractors. This should ensure contractors have sufficient income to allow them to invest in staff training, plant and equipment to ensure their future viability. Our expectation is that contractors would have at least 10% of their staff undertaking formal trade training at any one time. This will be assessed periodically from the supplied list of competent persons (refer Appendix A).

Orion's policy for selecting contractors is to support regionally based contractors for mutual long term viability.

Contractors that are clearly standalone are considered in preference to contractors that have a direct power company association who will not be considered if their network is not open to direct competition.

Orion may consider an exception to provide specialist services not available from our existing contractors.

In order to maintain a viable emergency maintenance response contractor Orion currently have a sole source provision of emergency maintenance.

In order to retain sufficient resource in the event of a major emergency Orion have in place major emergency response contracts with identified Contractors.

Orion will enter into mutual aid agreements with contractors and power companies for assistance in the event of a major disaster.

The continued inclusion of Authorised and Invited Contractors is subject to ongoing review via Orion's tender and contract management processes. Contractors may be added or removed at Orion's discretion.

Being an Invited Contractor offers no guarantee of work, but provides the ability to tender for work contracted on a project by project basis.

The acceptance for Authorised Contractors to work on Orion's network will be granted upon the contractor entering into a Work Specific, Minor Works or Building and Plant Maintenance Contract, as appropriate, with Orion.

The ability for contractors to undertake the type of work will be confirmed by gaining the appropriate Entry Approval Certificate (E.A.C) and/or Permit Holder Certificate (P.H.C) and the identification of the necessary skills on the list of competent persons (Appendix A) supplied by the contractor.

The following customer driven work is considered contestable and as such can be carried out by all Authorised Contractors.

- Subdivisions
- New Connections
- Minor Customer Initiated Work
- Street Light Installation

The following list identifies the type of work able to be undertaken by, and the invited status of, Authorised Contractors. Only those Invited Contractors identified on this list may be requested to carry out work for Orion.

While comprehensive, the included list is not definitive, notably where the work to be carried out is of a particularly large, occasional or specialised nature.

Contractors identified thus ** are signed up to the Minor Works or Building Services or other work specific 2 or 3 year term contracts.

Contractors identified thus * are signed up to individual works contracts only.

CURRENT TERM CONTRACT STATUS

CONTRACTOR	CONTRACT	DESCRIPTION	EXPIRY DATE
Arbor-Tek Ltd	2006/008E	Tree Cutting	31 March 2007
Cherry Picker Specialists Ltd	2006/009E	Tree Cutting	31 March 2007
Connetics Ltd	2006/005E	Minor Works	31 March 2008
C.T. & Associates Ltd	2006/001E	Minor Customer	31 March 2006
Earl P Smith Ltd	2006/005E	Minor Works	31 March 2008
Electro-Tech Services Ltd	2006/005E	Minor Works	31 March 2008
FitzGerald Electrical Ltd	2006/005E	Minor Works	31 March 2008
Green Acres Lawn Mowing	2006/023E	Grounds Maint.	31 March 2008
HV Diagnostics Ltd	2006/010E	Partial Discharge	31 March 2006
Independent Line Services Ltd	2006/005E	Minor Works	31 March 2008
John McNeill Electrical Ltd	2006/001E	Minor Customer	31 March 2006
L&S Painting Ltd	2006/005E	Minor Works	31 March 2008
Line Maintenance Services (2004) Ltd	2006/005E	Minor Works	31 March 2008
Power Jointing Ltd	2006/005E	Minor Works	31 March 2008
Richdale Builders Ltd	2006/005E	Minor Works	31 March 2008
Ritchie Family Trust	2006/019E	Grounds Maint.	31 March 2008
Southern Tree Maintenance Ltd	2006/007E	Tree Cutting	31 March 2007
Telpower (1998) Ltd	2006/001E	Minor Customer	31 March 2006
TEMCO Ltd	2006/005E	Minor Works	31 March 2008
Transfield E&T (New Zealand) Ltd	2006/005E	Minor Works	31 March 2008
Trevor Saul	2006/005E	Minor Works	31 March 2008

LIST OF AUTHORISED CONTRACTORS

<u>Contractor</u>	<u>Type of Work</u>	<u>Status</u>
Connetics Ltd ** P O Box 2237 Christchurch Mail Centre CHRISTCHURCH 8015 ATTENTION: BOB TAYLOR	Substations Cables Lines Emergency Customer	Invited Invited Invited Sole Source
Transfield E&T (New Zealand) Ltd ** P O Box 16219 Hornby CHRISTCHURCH 8030 ATTENTION: VINCE WILLIAMS	Substations	Invited
Power Jointing Ltd ** P O Box 364 Kaiapoi CHRISTCHURCH 8252 ATTENTION: PAUL GOLDING	Cables Customer	Invited Appendix B
Independent Line Services Ltd ** P O Box 24027 East Linwood CHRISTCHURCH 8030 ATTENTION: GARY O'MALLEY	Lines Customer Major Emergency Response	Invited Appendix B Invited
Line Maintenance Services (2004) Ltd ** 3 Mapledale Pl Halswell CHRISTCHURCH 8003 ATTENTION: PAUL VAN DER KLEY	Lines Customer Major Emergency Response	Invited Appendix B Invited
HV Diagnostics Ltd * P O Box 33078 Barrington CHRISTCHURCH 8030 ATTENTION: GREG LINTON	Plant Testing/Monitoring	Invited
Arbor-Tek Ltd ** P O Box 37187 Halswell CHRISTCHURCH 8030 ATTENTION: BERNIE JORDAN	Trees	Invited

<u>Contractor</u>	<u>Type of Work</u>	<u>Status</u>
Cherry Picker Specialists Ltd ** P O Box 18668 New Brighton CHRISTCHURCH 8030 ATTENTION: MARK GLASSEY	Trees	Invited
Southern Tree Maintenance Ltd ** 34 Karanga Rd R D 2 LEESTON ATTENTION: GARETH DAVIES	Trees	Invited
Richdale Builders Ltd ** 12 Duncan St Sumner CHRISTCHURCH 8008 ATTENTION: EOIN RICHDAL	Seismic	Invited
C.T. & Associates Ltd ** P O Box 13256 Armagh CHRISTCHURCH 8031 ATTENTION: GEOFF CHAPMAN	Customer	Appendix B
John McNeill Electrical Ltd ** P O Box 31154 Ilam CHRISTCHURCH 8030 ATTENTION: JOHN MCNEILL	Customer	Appendix B
Telpower (1998) Ltd ** P O Box 9185 Addington CHRISTCHURCH 8030 ATTENTION: SHANE DONALDSON	Customer	Appendix B
Electro-Tech Services Ltd ** P O Box 22676 High St CHRISTCHURCH 8032 ATTENTION: STEVE WALKER	Building Maint (Electrical)	Invited
L&S Painting ** 11 Porritt Pl Dallington CHRISTCHURCH 8006 ATTENTION: KEITH SPENCER	Building Maint (Painting)	Invited

<u>Contractor</u>	<u>Type of Work</u>	<u>Status</u>
Earl P Smith Ltd ** 2/8 Pawaho Pl Heathcote Valley CHRISTCHURCH 8002 ATTENTION: EARL SMITH	Building Maint (Carpentry)	Invited
Trevor Saul ** Lawcocks Rd R D 1 AMBERLEY ATTENTION: TREVOR SAUL	Building Maint (Carpentry) Grounds Maintenance	Invited Invited
Ritchie Family Trust ** 22 Croydon St Beckenham CHRISTCHURCH 8002 ATTENTION: ANTHONY RITCHIE	Grounds Maintenance	Invited
Green Acres Lawn Mowing ** P O Box 7125 Sydenham CHRISTCHURCH 8035 ATTENTION: PAUL MACFARLANE	Grounds Maintenance	Invited
FitzGerald Electrical Ltd ** Okuti Vallery Rd R D LITTLE RIVER ATTENTION: MARK FITZGERALD	Rural Operator	Invited
Electrix Ltd P O Box 1507 Waikato WAIKATO 2015 ATTENTION: TANGI GLASSIE	Tower Painting	Invited
TBS Farnsworth Ltd P O Box 56416 Dominion Rd AUCKLAND 1030 ATTENTION: GRAHAM MATTHEWS	Tower Painting	Invited
TEMCO Ltd ** P O Box 460 Te Awamutu WAIKATO 2400 ATTENTION: CHRIS MUNN	Tower Painting Network Surveys	Invited Invited

<u>Contractor</u>	<u>Type of Work</u>	<u>Status</u>
Tobins Ltd P O Box 50267 Porirua WELLINGTON 6215 ATTENTION: MIKE TOBIN	Tower Painting	Invited

APPENDIX B

NOTE: Contractors undertaking connections using live line techniques will be required to have procedures in place ensuring appropriate industry live work procedures are used.

Independent Line Services Ltd

Where Independent Line Services Ltd has built a low voltage underground cable extension for a customer, Orion will allow the following:

- Connection to Orion's existing LV overhead network by using live line techniques
- Connection to Orion's existing LV cable network by using de-energised techniques
- The operation of any low voltage fuses associated with the new connection

Line Maintenance Services (2004) Ltd

Where Line Maintenance Services Ltd has built a low voltage underground cable extension for a customer, Orion will allow the following:

- Connection to Orion's existing LV overhead network by using live line techniques
- Connection to Orion's existing LV cable network by using de-energised techniques
- The operation of any low voltage fuses associated with the new connection

C.T. & Associates Ltd

Where C.T. & Associates Ltd has built a low voltage underground cable extension for a customer, Orion will allow the following:

- Connection to Orion's existing LV overhead network by using live line techniques
- The operation of any low voltage fuses associated with the new connection

John McNeill Electrical Ltd

Where John McNeill Electrical Ltd has built a low voltage underground cable extension for a customer, Orion will allow the following:

- Connection to Orion's existing LV overhead network by using live line techniques
- The operation of any low voltage fuses associated with the new connection

Power Jointing Ltd

Where Power Jointing Ltd has built a low voltage overhead line extension for a customer, Orion will allow the following:

- Connection to Orion's existing LV overhead network by using live line techniques
- The operation of any low voltage fuses associated with the new connection

Telpower (1998) Ltd

Where Telpower (1998) Ltd has built a low voltage underground cable extension for a customer, Orion will allow the following:

- Connection to Orion's existing LV overhead network by using live line techniques
- The operation of any low voltage fuses associated with the new connection

APPENDIX C
CONTRACTOR ACTIVITY MATRIX
TBA



POST CONTRACT EVALUATION

ELECTRICITY NETWORK PROCEDURE STANDARD NW73.10.16

DISTRIBUTION REGISTER	
Copy	Issued To
1	Network Information Supervisor
2	Network Asset Manager

AMENDMENT RECORD					
Amendment No.	Page Amended	Amend Date	Date Inserted	Inserted by	Approved by
1		15.01.04			

The above table lists the amended pages in this standard, which have been distributed following the initial issue of this standard. Please insert the amended pages and discard the replaced pages.
 An update table is issued with each amendment. Check the new pages inserted against the table and fill out the "Date Inserted" and "Inserted By" spaces when inserting the amended pages.
 Amendments are marked with a vertical line against the left margin.

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POST CONTRACT EVALUATION

Contract 200 / _____ E

Factor	Definition	Assessment				
		1	2	3	4	5
1. Relevant Experience	Demonstrated experience, particularly in technical areas relevant to the Specification.					
2. Track Record	Completion of the project to target, performance levels, on schedule, within budget and safely.					
3. Competency and Technical	Competency of personnel with respect to the technical and legal requirement of the Specification. Including appropriately trained, certificated and experienced persons for the class of work required to be done.					
4. Adequacy of Safety	Compliance of the Health and Safety Management Plan in meeting the requirements of the HSE Act, Electricity Act and Electricity Regulations, Resource Management Act, and all other statutory requirements.					
5. Quality Assurance	Adequacy of procedures and programmes providing quality control of work processes.					
6. Customer Service	Level of commitment to the delivery of the specified Customer Service standards.					
7. Management Skills	Provision of people and systems appropriate to the successful management of the project.					

1. Excellent 2. Good 3. Adequate 4. Review Procedure 5. Review Contractor Status

Comments:	
Signed:	Date:

Procurement policy

Approved by the board
6 June 2012

OR00.00.19

Details of document amendment no. 2	
Section amended	Description
	No changes.

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Table of contents

1.	Introduction.....	4
2.	Risk based approach.....	4
3.	Strategic approach	4
4.	Framework for network procurement	5
4.1	Ten year network asset management plan (AMP)	5
4.2	Delegations of authority policy – OR00.00.11	6
4.3	Fraud and theft policy – OR00.00.08.....	6
4.4	Contract management policy – NW73.00.03.....	6
4.5	Authorised contractors procedure – NW73.10.15.....	6
4.6	Contract tendering procedure – NW73.10.09.....	6
4.7	Contract administration procedure – NW73.10.07.....	6
4.8	Request for pricing procedure – NW73.10.10	6
4.9	Contract responsibilities procedure – NW73.10.08	6
4.10	Standard contract document policy – NW73.00.01	6
4.11	Standard contract procedure – NW73.00.02	6
4.12	Evaluation of tenders policy – NW73.10.13.....	7
5.	Non-network procurement.....	7
6.	Conclusion.....	7

1. Introduction

The objective of this policy is to ensure the following good practice principles are incorporated in all purchasing/procurement decisions made by Orion employees:

- to reflect the accountability of managers to the board, and of the board to shareholders
- to ensure best value for money
- to encourage and maintain effective and sustainable competitive markets among our suppliers
- to ensure lawfulness, fairness and integrity at all times

2. Risk based approach

We seek to prioritise control over purchasing decisions made by employees where higher financial values are involved and/or where outcomes are less certain.

We mitigate risk through our policies, procedures and practices which provide guidelines for employees around procurement and by developing long term contractual relationships with key suppliers.

3. Strategic approach

Our strategic approach to procurement is described as follows. We will seek:

- to procure only when it is in the best interests of Orion to do so
- to 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.
- 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
- to effectively mitigate and/or manage potential liability and other risks created via procurement
- to manage our procurement with competent employees and expert advisors, and appropriate policies and procedures
- to encourage open, effective and sustainable competition between eligible suppliers
- to keep adequate records of our procurement, policies, procedures and decisions that facilitate audit and normal processes of accountability
- to comply with all applicable legal and contractual obligations
- to effectively manage all intellectual property rights and obligations created via procurement
- to effectively mitigate and/or manage any potential conflicts of interest in an open and acceptable manner

- to comply with any confidentiality obligations arising from the procurement process
- to have fair and transparent procurement processes that are free from fraud and impropriety
- to 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**
- to consistently innovate and improve on our procurement activities

As described in section 2 above and section 4 below:

- we adopt a risk based approach to our key procurement decisions
- our key procurement decisions largely relate to our management of our electricity distribution network, which accounts for over 80% of our cash expenditure (opex and capex).

Our key procurement document is therefore considered to be our ten year network asset management plan (AMP). Our AMP sets out our demand growth assumptions, our key network risks and our proposed spending priorities. Our spending in any year should be consistent with the current approved version of that plan. Exceptions to this plan occur, for example, when demand growth assumptions change, new information comes to light relating to key AMP assumptions or emergencies occur.

In all cases, we aim to invest in our network using a risk based approach (prioritised via a combination of likelihood and consequence) using good industry practice. The higher the overall risk, the greater the management focus.

Our AMP is a public document and we welcome comment from all of our stakeholders (including customers and suppliers) on any improvements that will enhance our AMP and procurement outcomes.

4. Framework for network procurement

We use a number of key policies and procedures to provide guidelines to employees for procurement.

With the exception of our Delegation of Authority policy, the other documents listed below are predominantly used in the Infrastructure group for network maintenance and development.

These documents control over 80% of cash expenditure per annum (excluding transmission charges and salaries/wages).

5. Ten year network asset management plan (AMP)

Our AMP outlines our forecasts for customer demand, our service standards, our key risks and our proposed procurement priorities for the next ten years. This plan is updated and is approved by the board before the start of each new financial year. Our AMP is published on our website and is open for public comment.

5.1 Delegations of authority policy – OR00.00.11

This policy outlines our general expenditure and approval rules for Orion.

5.2 Fraud and theft policy – OR00.00.08

This policy sets out our intention that all individuals associated with Orion will act with honesty, integrity and opposition to all forms of fraud and theft.

5.3 Contract management policy – NW73.00.03

This policy outlines our intentions to develop, promote and retain a group of competent contractors with due regard to long term network security and quality of the work performed.

5.4 Authorised contractors procedure – NW73.10.15

This procedure identifies the contractors which are approved to work on our network and outlines the method for selecting tenderers for procurement.

5.5 Contract tendering procedure – NW73.10.09

This procedure outlines our process for the basic preparation of the contract documents, the calling and closing of tenders and the evaluation of tenders through to accepting and notifying tenderers.

5.6 Contract administration procedure – NW73.10.07

This procedure outlines our minimum contract administration timeframes to allow for the processing of a contract through tendering to the possession of the work site by the successful contractor.

5.7 Request for pricing procedure – NW73.10.10

This procedure contains a form that employees who request works fill in and provide to the contract administration team to start preparation of the contract documents and the initiation of the tendering process.

5.8 Contract responsibilities procedure – NW73.10.08

This procedure identifies the relevant timeframes, functions and responsibilities of employees when requesting works to be priced and constructed.

5.9 Standard contract document policy – NW73.00.01

This policy details the responsibilities of employees around the preparation and creation of a standard contract based around NZS3910:2003. It also details the main technical specifications relevant for any contract.

5.10 Standard contract procedure – NW73.00.02

This procedure indicates a basic flow chart process around a standard contract.

5.11 Evaluation of tenders policy – NW73.10.13

This policy outlines the method used to assess/evaluate tenders and predominantly endorses the lowest conforming tender method.

6. Non-network procurement

Non-network procurement is wholly subject to our Delegations of Authority policy.

In particular, contracts for large value purchases are provided by the detailed schedule (Appendix 1 – specific spending authorities) within the policy.

Some items of significant expenditure are not subject to standard procurement policy rules - for example, rates and industry levies can be checked against the levy rate schedules and are not able to be negotiated.

Purchases for amounts in excess of \$50,000 will be made on an official Orion purchase order.

Purchases for amounts between \$20,000 and \$50,000 are to be made in writing.

7. Conclusion

We have a range of policies and procedures to help achieve the best overall procurement outcomes for Orion. This policy will be reviewed annually and approved by the board.

Appendix 33

Rider Levett Bucknall estimates

29 October 2012

Orion New Zealand Ltd
PO Box 13896
CHRISTCHURCH

Attention: Mr David Freeman-Greene

Dear Sir

ESCALATION COSTS FOR CANTERBURY CONSTRUCTION WORKS

Further to our recent discussion regarding likely escalation costs in Canterbury over the next 3-7 years. As discussed we do not get to see a lot of Civil projects but we can comment on what we are seeing in Commercial Construction and this may be reflected through the civils costs as no doubt resources will continue to be stretched in both sectors.

At present commercial construction costs still remain fairly competitive especially at the main contractor level with many contractor's still looking to secure work over the next 12 months. It doesn't appear likely that any of the major anchor projects will really get underway until late 2013 at the earliest.

However we have seen some movement in pricing amongst a few sub trades were work is available. Precast Concrete and Steelwork costs have increased over the past few months as demand increases. Labour costs have remained fairly static over the past 18 months and we wouldn't expect them to increase over the next period and not come under pressure until the construction work really takes off. This is probably slightly different in the Civils area as this work is well underway in many areas. This being the case I'm sure there will continue to be increases in the cost of labour for civils works.

As no doubt you are aware the difficult thing is predicting what will happen when the workload increases and resources come under pressure. NZIER are forecasting Non Residential Building Cost increases (on a national average) of approx. 2013 (3.3%), 2014 (4.2%), 2015 (4.2%). We have been using at present in our estimates 5% per annum increase for each year moving forward up to 2017. We haven't looked at anything beyond that date at present but would suggest that we would still be using the 5% figure until such time as we start to see things moving and get more accurate figures based on the actual movements in cost. In theory material costs shouldn't increase outside of normal annual increases and it will be labour costs that are likely to drive the costs up as resources become harder to obtain. We are also likely to see main contractor costs increase as their direct management labour becomes more expensive to retain and they are likely to increase their margins as more work becomes available.

Should you require any further information please contact us.

Yours faithfully



Malcolm Timms
Director
Rider Levett Bucknall

Appendix 34

Davis Langdon estimates

24 October 2012

Orion New Zealand Limited
General Manager (Commercial)
PO Box 13896
CHRISTCHURCH

Attention: David Freeman-Greene

Dear David

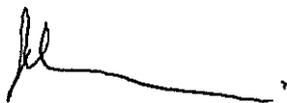
Labour Costs in the Canterbury Region

Further to your request for a view on the likely annual rate of change in labour costs commencing with the percentage change in 2013 and annually thereafter to 2019, we comment as follows:-

- 1) We know that there will be a lack of skilled resources over the next few years. Costs have already increased beyond belief
- 2) Recent Civil Works tenders have seen a 50% uplift in labour rates over the past two years (post-earthquakes)
- 3) Labour rates in the Building Construction industry have increased by 25% over the past two years (post-earthquakes)
- 4) Considering the above, we suggest an annual increase of 10% for each of the next 4 years (given the forthcoming Christchurch rebuild) and then 5% for the following 3 years up to 2019 (given prices must self-level over time) would be a reasonable allowance to make at this point in time.

I trust the above is satisfactory for your requirements

Yours sincerely



Ross Davidson
Technical Director
rdavidson@davislangdon.co.nz

Mobile: +64 21 241 0393
Direct Dial: +64 3 940 0981

Appendix 35

Ian Harrison and Associates estimates

IAN HARRISON and ASSOCIATES LTD

CONSULTING QUANTITY SURVEYORS

100 Victoria Street, Christchurch 8144, P.O. Box 21-393, New Zealand
Tel (03) 366-5881 or (03) 366-7375, Fax (03) 379-6866

2010. Celebrating 40 years Quantity Surveying

6th November 2012

David Freeman-Greene General Manager Commercial Orion Group

Orion Contracts Christchurch - 6 Year Forecast of Likely Cost Escalations

INTRODUCTION

Following the Earthquake Damage in Christchurch the various sectors in the Construction Industry are faced with an increased workload in the widely publicised Rebuild.

As Orion contracts would be affected by any abnormal cost escalations that result from this, we have been requested to state an opinion on Labour Costs Escalations to 2019, and in response we report on Construction Cost Escalations which are primarily influenced by labour costs, and as manufactured materials also contain a labour content we consider the Construction Cost Escalations are a reliable guide for labour cost increases. The Rebuild workload of increased activity is directly labour related.

THE CONSTRUCTION MARKET

This comprises a series of Market Sectors, some inter-related, but workloads can and will vary between sectors. Having been involved with Orion on many Insurance Claims for buildings and infrastructure, we envisage a large percentage of Orion's future workload being in the Civil Construction sector, and this has sub-sectors related to various essential services involved.

Buildings for Orion would be in the Commercial Building sector, and most 11kV substations are of restricted size and value, but district substations with 66kV inputs are far more complex.

We do not envisage Orion having any direct involvement in the Residential Housing market, other than supply of services via the Civil Construction sector.

THE CIVIL CONSTRUCTION SECTOR

There is no doubt activity in this sector is high and will increase due to damages to essential services. SCIRT has been formed to organise and complete a wide range of repairs and replacements to water supply, sewers and stormwater mains, and this is presently only 12% complete and projected to continue to at least 2006, excluding roading repairs.

Roading repairs are a very large activity, forecast to take 7 years to complete.

Directors:

Ian Harrison Life Member NZIQS, FNZIM, Reg. QS, Past President NZIQS

Grant Moore ANZIQS, MNZIOB

Stewart Harrison MNZIQS, Reg. QS

The conclusion is this sector will have very high workloads for several years, and in our opinion will draw on extra resources not currently available. While presently Commercial Buildings are at a modest level we suspect some labour resources from this have already transferred to the Civil sector for better pay rates etc.

In summary this is the sector most under resourced, but is capable of increasing outputs with external sourcing of machinery and operators – this is exactly what is taking place. Costs increase as a direct result of excessive demand.

THE COMMERCIAL CONSTRUCTION SECTOR

Here we have a real challenge. Previous forecasts of increased activity have not materialised – a quick tour of the CBD demonstrates demolition is still underway with more to complete 2 years on. We understand there are delays in Insurance settlements, and complexity in these, which has held back the expected rebuild. Earlier forecasts did not appear to anticipate these factors. Our office has been heavily involved in Insurance claims in this sector, and settlements are slow due to oversees Re-insurers requiring details and costs, and Owners considering options including cash out.

It is still not clear how commercial returns will be achieved as higher construction costs suggest higher rentals, yet displacement of offices after Feb 2011 occurred rapidly to suburban locations (by necessity) – will this demand return or stay suburban at lower construction costs and lower rentals ?

Activity forecast at \$4B has to be viewed over a specific timeframe, and if say 10 years this would equate to \$400M per year which is within present capacity. If the timeframe shortens cost will then escalate further, this possibly lowering returns.

The outcome of this sector remains somewhat uncertain on timings, dependant on activity levels which if these ramp up noticeably will place pressure on labour resources.

THE RESIDENTIAL CONSTRUCTION SECTOR

This is clearly documented as being short of housing stock due to earthquake damage – 7,860 houses are Red Zone, with considerably more with major damage. In the last 2 years the CCC has issued \$636M of earthquake related consents for both residential and commercial properties. This acknowledges considerable non consent repairs (mainly residential) have also taken place. New houses total 616 in the last 2 years to Sept 2012, this being well short of the number of condemned Red Zone houses. Insurer IAG announced 5th Nov it would have 100 new homes completed by Xmas and 500 total by June 2013, as well as 450 major repairs completed. There were reservations expressed about these targets, but if achieved they remain low percentages of the total demand.

This sector is under pricing pressures from high land and construction costs, and compared to the foregone value of a depreciated Red Zone house, the difference in cost is requiring Owners funds (cash or more likely mortgage). This may explain slow rebuild figures – affordability.

In summary new house construction is to increase and repairs are possibly 4 years from completion – both these suggest increased activity spread over time.

FORECAST OF LIKELY COST ESCALATIONS – Labour and Materials to 2019

CIVIL SECTOR - clearly under the most pressure for resources – 20% to 25% inflation over the next 2 years, then averaging 7% to 8% per annum (double the normal rate)

COMMERCIAL CONSTRUCTION SECTOR - some movement due very soon – 15% inflation over the next 2 years, then averaging 6% to 7% per annum.

RESIDENTIAL CONSTRUCTION SECTOR- a 10% increase has just occurred with another rise likely to be 15% total over 2 years, then levelling out to 4% to 5% per annum.

QUALIFICATIONS

The above is reliant on anticipated activity for the Earthquake Rebuild. The timeframes for Civil are already established, whereas Commercial will be subject to investment decisions, and Residential to affordability. Any overseas financial crises affects our economy and inflation, as imported material content, and will alter our forecasts.

While the initial request was for labour cost increases we believe the current general sector costs escalations will focus on and represent higher demand for labour, hence labour costs will rise as the most inflationary factor in construction costs. The linkage between skills and productivity drives labour costs higher for contractors requiring and competing for these attributes. Management costs also rise due to shortages in professionals required, and contractors in some cases are arranging worker accommodation (at a cost). These are 'bundled' into general construction costs, labelled escalations but in this instance represent labour cost increases.

We offer the above Forecasts in good faith but with no guarantee as the variables present can alter our present assumptions.

We trust this is of assistance to Orion NZ Ltd in assessment of labour cost increases.

Brian Le Fevre for Ian Harrison and Associates

Email brian@harrisons-qs.co.nz