NORTH ISLAND GRID UPGRADE PROJECT

APPLICATION FOR INCREASE OF MAJOR CAPEX ALLOWANCE

Transpower New Zealand Limited

September 2013

Keeping the energy flowing

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Transpower New Zealand Limited The National Grid

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1 Executive Summary

Transpower is applying to the Commerce Commission for recovery of costs incurred on the North Island Grid Upgrade Project (**NIGU Project**). These costs have exceeded the maximum capex allowance (**MCA**) of $824 million approved by the Electricity Commission in 2007.[1]

We forecast the expected final expenditure for the NIGU Project will be $894 million, being $70 million greater than the 2007 MCA. This expenditure excludes some costs previously expensed,[2] and the net costs of freehold property purchases, which are not recoverable from customers and for which we have already received an impairment to our accounts.[3]

We believe the expected final expenditure of $894 million was reasonable and efficiently incurred, in the circumstances in which the NIGU Project was planned and delivered.

1.1 Establishing a revised MCA

Transpower is very proud to have delivered a critical piece of infrastructure in the NIGU line. We have done so cost effectively, efficiently, ahead of the required need date, and in a manner that enhances the transmission infrastructure in New Zealand for the benefit of transmission customers and electricity consumers alike. In determining an amended MCA, we believe the Commerce Commission will wish to take account of all the relevant circumstances under which the project was planned and delivered.

The detailed circumstances are set out in the following sections of this application. They include various delays, which not only deferred commissioning of the project, but resulted in some additional costs being incurred.

These delays were caused by several factors:

- Our planning was later than ideal in identifying the need for the project;
- The regulatory approval process, undertaken in conjunction with the newly-formed Electricity Commission, was prolonged; and
- The process for environmental consenting via a Board of Inquiry on a de novo application took significantly longer than anticipated.

The process for obtaining regulatory and environmental approval was unfamiliar to all parties, reflecting the fact that no transmission project of the NIGU Project scale had been undertaken in

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1 The term “major capex allowance” (MCA) did not appear in the Electricity Governance Rules, used by the Electricity Commission to approve the NIGU Project. They used terms such as “approval amount” or “maximum approval amount”, or “P90”. However reflecting clause 1.1.4(2)(a)(i) of the Capex IM, we use the term MCA in this application as a reference to the quantum of major capex previously approved by the Electricity Commission for the NIGU Project.

2 Investigation costs in the 2004/05 year and the cost of and income from dismantling the Arapuni-Pakuranga 110kV line.

3 Impairments have been incurred as follows:

2009/10 $30.0million

2010/11 $19.7million

2011/12 $1.4million

New Zealand for several decades, and both the Electricity Commission regulatory approval and Board of Inquiry processes were being used for the first time.

The late planning and protracted approval processes had a significant and adverse impact on landowner relations and related property negotiations for the overhead line. The timing pressures led to initial property negotiations being progressed without the requisite regulatory approvals for the Project. This was done in an effort to meet the final project need date, recognising the potential for property acquisition to set the critical path for the project.

In the absence of regulatory approvals however, we were unable to secure adequate property rights within a timetable that enabled optimal construction activities. The property negotiations were protracted and easement acquisition was fragmented.

Some costs for the overhead line works would have been avoided had there been more time to address the property issues, and had the regulatory process not increased opposition to the line and further delayed negotiations with landowners. In particular, the fragmented availability of property access and easement rights and associated lack of geo-technical data meant that foundation work, tower erection and conductor stringing could not be optimally sequenced.

Some of these factors are found in any major project of this type and the relevant question is whether appropriate project management and cost control processes were in place to effectively manage the project. We believe they were, and therefore, we believe the expected final expenditure of $894 million was reasonable and efficiently incurred, in the circumstances.

However, due to the contribution of later than ideal planning to the delays and additional costs, we consider it is appropriate to recover (and receive a return on) a lower amount from transmission customers, of $876 million.[4] This is a reduction of $18 million to the expected final NIGU Project cost. This $18 million amount is based on additional costs submitted as scope change requests for the overhead line works which are attributable to sub-optimal sequencing of construction activities for the new overhead line, and is consistent with our expectation that the overhead line construction costs could have been approximately 5% less than the now expected final costs. In our view, these costs may have been avoided with the benefit of perfect planning and earlier availability of property.[5]

Accordingly, while we seek an increase in the MCA for the NIGU Project to $894 million (on the basis that this represents reasonable and efficient expenditure), Transpower intends to only recover (and receive a return on) $876 million.[6]

We have also written-off more than $50 million from the value of freehold properties acquired for the NIGU Project. Early in the Project, we pursued a strategy of purchasing freehold properties,

4 Notwithstanding that the Commission may determine that, in all of the circumstances, $894 million is reasonable and efficient expenditure.

5 As stated above, further additional costs for the overhead line works (in excess of our current forecast of $894 million) may have been possible due to a commercial dispute with BBUGL relating to the overhead line works. Transpower denied that BBUGL was entitled to additional value. Transpower and BBUGL have reached an agreement in principle to settle this commercial dispute. The agreement remains to be documented and executed. Transpower does not anticipate that BBUGL will seek to reopen the dispute prior to execution.

6 We have set out in Appendix 2 the mechanism we propose to enable this lower cost recovery. We would expect to discuss and agree this mechanism with the Commission before applying it.

rather than easements. This strategy was advanced to mitigate the risks of project delay from protracted easement negotiations, and to address the opposition to the project, which had been exacerbated by the prolonged regulatory processes. The subsequent drop in market value of these properties crystallised a risk we were exposed to in pursuing this strategy.

These additional costs are outside of the ambit of this submission and are not recoverable from customers under the current regulatory framework. They are, nonetheless, a real cost which we incurred in seeking to deliver the project by the identified need date. In our view, the final project cost would have been materially higher than $894 million and completion would have been significantly later, had we not adopted this strategy and incurred these costs.

NIGU is one of three very large grid upgrades undertaken by Transpower over the last five years, the others being the HVDC Pole 3 Project and the North Auckland and Northland (NAaN) Project, with MCAs of $672 million and $415 million respectively. We expect that, in aggregate, these three projects will be completed for around $80 million less than their combined regulatory maximum approved cost of approximately $2 billion, a benefit that inures, in large part, to electricity consumers and not Transpower.

1.2 The NIGU Project

The NIGU Project was the first new transmission line project in New Zealand since the 1980's and included construction of three new substations, 186km of overhead lines with 426 towers, and 11km of underground cabling. The works provide a significant increase in transmission capacity to the upper North Island, initially at 220kV with the ability to increase this in the future to 400kV.

On the basis of the Electricity Commission's stipulated demand scenarios, the Project was required by mid-2013 to ensure reliability of supply to Auckland and Northland, as well as supporting and facilitating new generation investment and renewable energy.

The NIGU Project was delivered by the forecast need date and to the required standard.

1.3 Implementing the NIGU Project

Planning for the NIGU Project began in 2003, with initial communication with potentially affected landowners occurring from October 2004. We submitted a Grid Upgrade Plan (GUP) to the Electricity Commission in 2005 and an amended GUP (as the initial plan was declined) in October 2006. The amended GUP was approved in mid-2007 following extensive public consultation.

A Board of Inquiry was established under the Resource Management Act to consider the project's environmental impact and designation for the line route. The Board of Inquiry granted approval in September 2009, more than a year later than originally signalled. Overall, six years elapsed between the start of planning and all regulatory and environmental approvals being in place to commence construction.

We commenced the acquisition of property rights in 2006, but many landowners refused to engage until all regulatory approvals were acquired in 2009 believing that regulatory approvals might not be granted, and that additional leverage could be secured by delaying engagement. The difficult landowner engagement resulted in more limited property access, which restricted the geotechnical analysis on which to base cost estimates to the Electricity Commission.

Options of delaying or reconfiguring the works programme were considered. However, following analysis these were considered to be either more expensive,[7] or to result in unacceptable risks to the reliability of the grid, in particular the reliability, resilience and stability of supply into Auckland.

Ultimately, proceeding with the overhead lines construction works prior to the acquisition of all necessary property rights and completion of site investigations, while the lowest cost and most system secure option available, resulted in suboptimal construction sequencing (principally foundation, tower erection and stringing), when measured against the optimal activity sequencing for this project as initially envisaged.

1.4 Review of the expenditure on NIGU Project works

1.4.1 Property

Expenditure on acquiring property rights was higher than initially forecast. However the additional, unforeseen costs were well managed under the circumstances prevailing at the time and, accordingly, we consider all property expenditure was reasonable and efficiently incurred.

Easement compensation was paid to landowners on the basis of land valuations, which were increasing in line with the general trend in the property market at the time and at a much greater rate than anticipated by the GUP cost estimate assumptions. Increasing valuations together with landowners' perceived increased negotiation leverage (for the reasons already stated), resulted in further escalation of compensation payments.

While it is possible that recourse to compulsory acquisition may have reduced the compensation ultimately paid for the easements, further delays to the Project due to the compulsory acquisition process would have increased costs beyond those we incurred in pursuing negotiated and earlier settlements with landowners.

A number of additional property related costs were incurred that were not originally forecast. These included: costs and/or compensation for moving or demolition of buildings and other hazards, and for land use change; costs associated with tree removal (and associated Emissions Trading Scheme liabilities); higher than anticipated labour costs; and the costs associated with properties required to be retained in the long-term.

As noted earlier, the strategy of freehold purchase of some properties to mitigate protracted easement negotiations created "momentum" for the route acquisition and the Project as a whole.[8] However, the loss of value on re-sale of properties, once easements were registered, has led to Transpower writing-off costs of more than $50 million.[9]

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7 The other options were considered likely to be more expensive for a variety of reasons, including loss of key suppliers, accumulation of interest during construction and overheads.

8 97 properties were purchased at a total cost of approximately $210 million.

9 We note that Transpower acquired these properties at its own risk to ensure a critical mass of strategic property rights were secured to allow the Project to proceed. Had Transpower not acquired these rights the overall Project costs would have been significantly higher, albeit still reasonable and efficiently incurred. Despite this, Transpower does not seek to recover any of these costs.

1.4.2 400kV overhead transmission line

Construction of the overhead line for the Project was extremely challenging with suboptimal sequencing impacting the cost of foundation, tower erection and conductor stringing works.

This could have been avoided had the necessary property rights been obtained earlier and/or the Project timetable allowed for more time to obtain them. Delays caused by the prolonged regulatory process were out of Transpower's control. However, it is acknowledged that had Transpower started planning earlier, some of this additional cost may have been avoided.

1.4.3 Underground cables, substations, deferral projects, project management

Expenditure on the underground cables, substations, deferral projects, project management, investigations and environmental components of the NIGU Project was reasonable and efficiently incurred. The associated works were managed in accordance with Transpower's standard project management processes, and the costs managed through competitive tendering and other prudent cost control mechanisms. Expenditure on these works was below the amounts estimated for the GUP approved by the Electricity Commission, with the exception of environmental costs, which increased due to the prolonged Board of Inquiry process as already stated.

Some savings resulted from obtaining consents for, and building, outdoor versus indoor switchgear at Pakuranga.

1.5 Changes to approved major capex project outputs

As mentioned above, during the delivery of the NIGU Project, for reasons of cost saving and system optimisation, we made a small number of minor changes to the physical outputs initially contemplated by the Grid Upgrade Plan approved by the Electricity Commission. This application addresses these changes, to the extent any formal determination of amendments to the approved major capex project outputs is required.

1.6 Conclusion

As discussed above and throughout this application the NIGU Project was the first major transmission line project for nearly three decades and was delivered by Transpower ahead of the required need date of mid-2013. We contend that not only was the final Project cost efficiently incurred, but that the NIGU Project is an extremely cost-effective contribution to the National Grid and New Zealand infrastructure more generally.

We have noted that as part of the suite of three major projects Transpower was charged with delivering, the NIGU, HVDC Upgrade, and NAaN projects have a combined regulatory approved cost of nearly $2 billion and we expect to deliver those three projects at a saving of $80 million, a benefit which goes to electricity consumers, not Transpower. It is also important to note that the NIGU Project would still satisfy the Grid Investment Test based on $894 million of actual costs, and that the electricity market benefits resulting from the Project remain substantially higher than the costs.

We consider that all $894 million of expenditure on the NIGU Project was reasonable and efficiently incurred in the circumstances. Accordingly, we seek an increase in the MCA for the

NIGU Project to $894 million. However, as noted, $876 million is the maximum amount that Transpower proposes to recover from transmission customers, on the basis that, arguably, we partly contributed to the circumstances which caused avoidable additional costs to be incurred.

2 The amendment sought

2.1 Quantum of proposed amendment to major capex allowance

The total expenditure on the NIGU Project is expected to be $894 million. Accordingly, we have incurred an additional $70 million above the MCA of $824 million.

We believe, given the circumstances, that all expenditure was reasonable and efficiently incurred. For that reason, we request the MCA for the NIGU Project be increased by $70 million to $894 million. However, as already noted, $876 million is the maximum amount that Transpower proposes to recover (and receive a return on) from transmission customers, on the basis that we partly contributed to the circumstances which had the potential to contribute to additional costs being incurred that may have been avoidable.

2.2 Calculations showing how the quantum of the proposed amendment was calculated

Forecast End Cost of NIGU Project	= $894 million
Electricity Commission approved MCA	= $824 million
Difference	= $70 million
Proposed increase in MCA	= $70 million

2.3 Assumptions made in the calculations

Forecast End Cost of NIGU Project = $894 million, comprised of:

Table 2-1: NIGU Project Forecast End Cost ($000)

	Actual cost to August 31st 2013	Forecast to project closure	Forecast End Cost
400 kV transmission line		-$12,494[10]	
Property		$6,700	
Cables		$2,898	
Project Mgmt, Environmental		$751	
Brownhill substation		$38	
Pakuranga substation		$453	
Whakamaru substation		$661	
	$894,835	-$993	$893,842

10 This figure is negative as Transpower expects to be reimbursed certain costs for the transmission line build.

2.4 Evidence in support of the calculation

Supporting detail and related documentation is available if required by the Commerce Commission.

2.5 Proposed P50

The proposed P50 is the expected cost of the NIGU Project in commissioning year dollars as outlined in the original GUP, being $764 million.

All grids outputs included in the NIGU Project have been commissioned and in that respect the project is complete.[11]

Therefore, given this is not an application for an increase in the MCA to cover significant future expenditure, we believe a proposed P50 for this application is not relevant.

2.6 Calculations, key assumptions, supporting evidence used to determine proposed P50

The calculations, key assumptions and supporting evidence used to determine the proposed P50 are addressed in the original GUP and not revisited in this application.

2.7 Proposed amendments to the approved major capex project outputs

During delivery of the NIGU Project, the following changes were implemented to the physical grid outputs as contemplated by the Grid Upgrade Plan approved by the Electricity Commission:

- We elected to build an Air Insulated Substation (AIS) at Pakuranga rather than a more expensive Gas Insulated Substation (GIS), as the resource consents for the NIGU Project ultimately permitted us to proceed with the AIS option and it was more efficient to do so. This was foreshadowed with the Electricity Commission at the time of its approval of the GUP.
- To optimise the effectiveness of reactive support, we divided the location of 350 MVAr of new static reactive plant between Otahuhu, Penrose and Hepburn Road substations, rather than installing the new plant entirely at Otahuhu substation.
- We have deferred the acquisition of some easements over Auckland Council and Crown land necessary for the future installation of new 220kV underground cables from Brownhill substation to Otahuhu substation. Given these cables are unlikely to be installed before 2025, we did not consider it is in consumers interests to purchase these easements now. Rather they will be purchased closer to the time the cables are ultimately required.

This application seeks concurrently, under clause 3.3.4(1)(d) of the Capex IM, a determination by the Commission to amend the approved major capex project outputs for the NIGU Project, in the

11 All grid outputs have been commissioned with the exception (as noted in section 2.7) of securing easements through Auckland City reserve land for the Brownhill-Otahuhu cable route.

manner described above. Set out in Appendices 4 and 5 of this application are further submissions on these changes, including references to where in this application the circumstances and justification for the change is discussed.

3 Progress of the NIGU Project

3.1 Overview of NIGU Project timeline

Table 3-2 below shows the high level timeline associated with the Project.

Table 3-2: Project History

Date	Project Status
2003	Transpower commences initial planning work on reinforcing supply into Auckland
October 2004	Transpower commences discussions with landowners over possible route for a new transmission line into Auckland
31 May 2005	Transpower submits initial North Island Grid Upgrade proposal under the transitional provisions of the Electricity Governance Rules
12 July 2005	Electricity Commission rejects use of the transitional provisions for this project and requests full Grid Upgrade Plan.
30 September 2005	Transpower submits initial Grid Upgrade Proposal to the Electricity Commission
31 May 2006	Transpower withdraws its initial Grid Upgrade Proposal after discussion with the Electricity Commission
20 October 2006	Transpower submits amended Grid Upgrade Proposal to the Electricity Commission
31 January 2007	The Electricity Commission issues a notice of its intention to approve the proposal. Public conference held in May 2007.
27 May 2007	Transpower lodged “Notices of Requirement” under the Resource Management Act 1991, with seven affected local councils
5 July 2007	The Electricity Commission announced its final decision to approval the proposal
9 August 2007	Consideration of the designations and resource consents required for the Project was “called in” by the Minister.
25 March 2008	Ministry for the Environment (MfE) Board of Inquiry commenced hearings of the Notices of Requirement and applications for resource consent
22 September 2008	Project Alliance Agreement (PAA) entered into with BBUGL for overhead lines works
31 October 2008	MfE Board of Inquiry hearings concluded
4 May 2009	The High Court turned down a request from New Era Energy to judicially review the Electricity Commission’s approval of the project
27 May 2009	MfE Board of Inquiry released its draft report and decision to approve the designations and consents required for the project under the Resource Management Act
May 2009	Project baselines established for works under the PAA
18 September 2009	MfE Board of Inquiry released its final report and decision approving the designations and consents required for the project
4 May 2010	First of the new transmission towers constructed
1 October 2010	Cables project mobilised on site
27 October 2011	Stringing of overhead conductor commenced
29 June 2012	Underground cable installation completed
30 October 2012	NIGU Project commissioned

3.2 Initial planning processes

3.2.1 Background to planning for the Project

With the projected growth rates for electricity demand in Auckland and/or Northland, there was a risk that some electricity demand could not be supplied at peak times from 2010 unless new generation was built in Auckland and/or Northland before then.

At that time,[12] there were no committed new generation projects in the region and so increasing transmission capacity to access the new generation that was being built further south was the only option to maintain security of supply into that region.

We identified that it was unlikely we would be able to commission substantial new transmission capacity until 2013, so looked closely at the existing infrastructure to see if there were any smaller projects which might bridge the gap between 2010 and 2013.

These “deferral projects” emerged from that exercise, consisting of:

- installation of 350 Mvar static reactive support at Otahuhu (to maintain a reasonable level of voltage stability in the region);
- thermal uprating of the Ohinewai to Whakamaru section of the Otahuhu–Whakamaru C line (increasing thermal transfer capacity into Auckland); and
- installation of a switching station at or around Drury (improving load sharing between lines and hence increasing capacity into Auckland).

These projects extended the need date to 2013, thereby allowing us to consider a wider range of long-term options.

We considered a wide range of options to meet the 2013 need date:

- Duplexing (doubling the number of conductors) existing lines;
- Use of High Temperature Conductor on existing lines;
- New 220 kV line options;
- New 400 kV line options;
- Use of classic HVDC technology (as per the existing inter-island link);
- Use of HVDC light technology (lower cost but lower power, similar to the technology adopted for Murraylink and Directlink in Australia);
- Under-grounding (either HVDC or HVAC);
- Peaking generation plant; and in our 2005 GUP:
    - New 330 kV line options; and
    - New 500 kV line options.

12 The same situation relating to the availability of generation in and around Auckland applies today.

Of these, three options were clearly more economic than the others:

- Building a new 400 kV capable line, operating it at 220 kV now and installing 400 kV transformers at some time in the future – estimated to be 2032;
- Building a new 220 kV line now, followed by a second new 220 kV line at some time in the future – estimated to be 2033; and
- Duplexing the existing Otahuhu–Whakamaru A&B lines now, followed by a new 220 kV line in 2020 and a second new 220 kV line at some time in the future – estimated to be 2036.

The first two options were close, with the duplexing option being more expensive, primarily because it was estimated to require three tranches of property easements.

The duplexing option offered an option value in that it minimised transmission expenditure before 2020. It would have looked attractive if there had been more likelihood of new generation emerging in the upper North Island by then.

The choice between building a new 400 kV capable line or a 220 kV line was more difficult. The economics marginally favoured a new 400 kV capable line ($10 million on a PV basis) but, given the uncertainty in the inputs to the economic analysis, the two options were economically equivalent.

The choice depended upon the likelihood of significant new generation being built in the region. We were of the view that, since no new significant generation was confirmed, we should build a new line and that one 400 kV line was better than having to build two 220 kV lines over time. The Electricity Commission were more of the view that 2030 was a long way away and it was unlikely the 400 kV transformers, or a second new 220 kV line, would be required so it would be better to build a 220 kV line now.

Ultimately, the Electricity Commission approved our proposal, albeit with some delay.

Our proposal demonstrated that 2013 was the need date. However, given the complexity of the works, and the fact that no project of this nature had been undertaken in over 40 years or under the current regulatory regime (i.e. Resource Management Act and Electricity Governance Rules),we considered it would be prudent to prepare an initial project plan which aimed for earlier commissioning – in 2011.

3.2.2 High level design

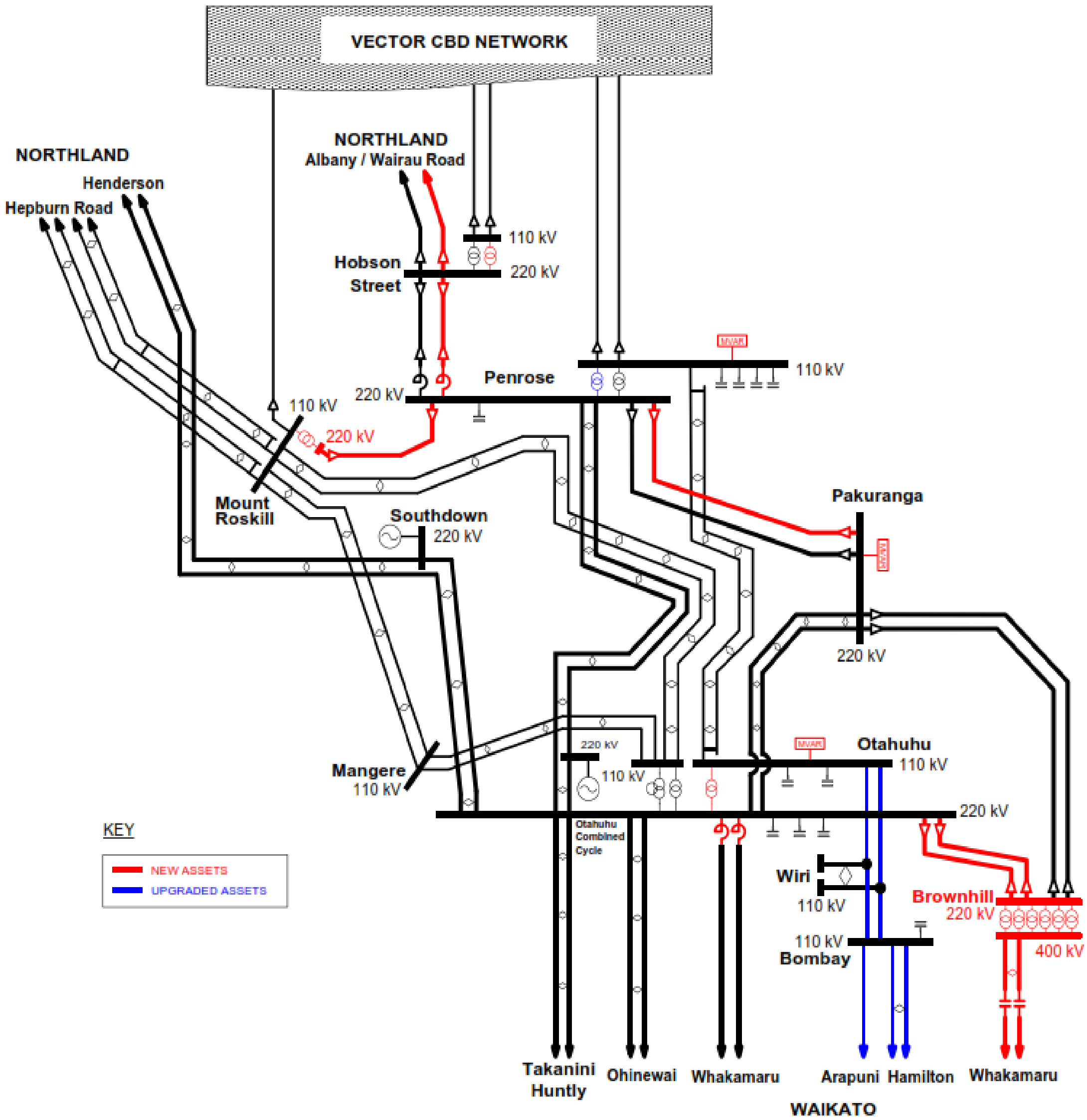
The NIGU Project primarily involved building a new 400 kV double circuit transmission line between Whakamaru and Brownhill, with 220 kV underground cables from Brownhill, first to Pakuranga and subsequently from Brownhill to Otahuhu,[13] plus associated substations.

13 The project included the acquisition of environmental consents and property rights for the later cabling from Brownhill to Otahuhu, with the actual procurement and installation being the subject of a further investment proposal closer to the time needed.

The new 400 kV capable double circuit transmission line has a capacity of 2700 MVA per circuit in winter. The transmission line is initially to be operated at 220 kV and series compensated after 2018 to defer conversion to 400 kV as long as possible.

Figure 3-1 is a diagram of the upper North Island grid, as it may possibly develop, showing the new enhancements.

Figure 3-1: Possible development of upper North Island Grid beyond 2028



3.2.3 Development of the line route

We publicised the proposal for a new transmission line in October 2004 and commenced consultation with landowners. We consulted on two proposed routes. This was before we had submitted our initial GUP to the Electricity Commission, which followed at the end of September 2005.

An indicative route alignment was published in July 2005, which had been designed using desktop analysis, roadside observations and a workshop involving environment specialists and engineers, as well as our initial engagement with landowners.

We undertook consultation on the line route between July 2005 and January 2006, including visiting properties. A final corridor was released in 2005, which was up to 5km wide with an indicative centreline. As a result of consultation, including landowner feedback, the centreline was finalised in January 2006 with approximately two thirds of the centreline (and consequently two thirds of the 426 towers) changed.

When we began consulting in October 2004, we had not yet submitted a GUP to the Electricity Commission and so had no indication of whether we would receive regulatory approval. Additionally, at the time, the regulatory environment for receiving GUPs (including the application of the Grid Investment Test) was still being bedded in.[14]

As this was the first new line to be built since the 1980s, landowners were surprised and upset by our communications. Our initial advances were greeted with opposition.

Once it became clear to landowners that we did not have regulatory approval to build the new line, this resulted in difficulties in accessing properties to survey the route and assess ground conditions.

We have since moderated and enhanced our approach to engaging with landowners, with the benefit of this experience.

The hostility that followed set the environment for difficult easement and compensation negotiations. The result was that we were unable to negotiate easements in a manner which allowed optimal construction of the new transmission line.

3.3 Electricity Commission decision

The original GUP for the NIGU Project was submitted to the Electricity Commission on 30 September 2005. This proposal comprised building a 400 kV line and installing 400 kV transformers by 2013.

This original proposal was later withdrawn and amended in response to feedback from the Electricity Commission. An amended proposal, reflecting installation of the 400 kV transformers being deferred, was submitted in October 2006.

During its decision-making process the Electricity Commission revised its timetable a number of times. The delays pushed out the timeframe to begin the next stages of regulatory approval.

Despite this, valuers were engaged to start compensation assessments and landowners were also invited to obtain their own independent assessments. The first easement agreement was signed in May 2007. We also entered into some purchase negotiations. Most landowners, however,

14 Hence our initial proposal in May 2005 under the transitional provisions for grid investment.

elected to wait until the final Electricity Commission decision was confirmed before they would enter negotiations.

The amended proposal was approved by the Electricity Commission on 5 July 2007. Following that approval, New Era Energy sought a judicial review of the Electricity Commission decision in the High Court. This process was lengthy and added to the uncertainty of the Project, but the Electricity Commission's decision was ultimately upheld on 4 May 2009.[15]

3.4 Board of Inquiry decision

Following the Electricity Commission's decision, the Minister of Energy (at the time, Hon Pete Hodgson) announced he would use powers under the Resource Management Act (**RMA**) to "call in" the NIGU Project, because of its national significance. This occurred on 9 August 2007. A Board of Inquiry (**BoI**) was subsequently established to consider the Notice of Requirement for a Designation required for the NIGU Project.

In February 2007, in preparation for the BoI process, we had confirmed a preferred 500m wide route within which the towers would be placed.

Originally, the final decision of the BoI was due in July 2008. This was later revised to be a draft decision by December 2008, and a final decision in 2009. In light of what was becoming a compressed timetable for construction of the new line, we had continued planning and seeking to advance negotiations with landowners to enable commencement of construction activities as soon as all regulatory approvals and consents were obtained. This planning included selection of a consortium formed between Balfour Beatty from the United Kingdom and United Group Limited from Australia (**BBUGL**) as an Alliance partner for construction of the overhead line. The Alliance contract for construction of the new Brownhill-Whakamaru line was awarded on 22 September 2008.

The December 2008 deadline for the BoI's draft decision was not met. A draft BoI decision was eventually issued on 27 May 2009, with submissions due on 24 June 2009 and no definite date for a final decision.

The BoI issued its final decision on 18 September 2009, over one year later than originally planned and two years after the Minister called the project in under the RMA.

3.5 Reasons for the unanticipated nature of the delay in the BoI process

There were several reasons for the BoI delay:

- There was strong opposition to the project, including from landowners, community organisations and local councils.

15 New Era Energy Inc was a group of directly affected landowners and neighbours. The decision of Justice Wild (delivered on 4 May 2009) to uphold the Electricity Commission's decision is set out in *New Era Energy Inc v Electricity Commission*, HC Wellington, CIV-2007-485-2774.

- A number of parties to the BoI process commissioned independent research into different options. The process considered an unusual number of possible alternatives to the project in its proposed form. These needed to be analysed and the findings of the Electricity Commission were not heavily relied upon by the BoI. In particular:
  - the Waipa District suggested an alternate route, the Eastern Route;
  - a number of parties investigated and presented options for under-ground cables, in particular near Morrinsville and into Manukau City; and
  - alternative tower types, monopoles, and so called “compact lines” were discussed.
- The BoI accepted a significant focus on issues which were noted to be outside the scope of the Inquiry, but still worth having presented, including:
  - property compensation;
  - easement terms such as indemnities and restrictions on land use;
  - perceived failings in the Electricity Commission’s decision-making process; and
  - alternative options to the project as a whole, such as generation near Auckland or upgrading existing lines.
- As the matter was heard by a Board of Inquiry, elements of the Commissions of Inquiry Act applied. This meant the Board was not tied to the ordinary rules of evidence and had power to admit any information it wished and allowed cross-examination of witnesses. It was. In effect and in application, a de novo hearing of all issues. As a consequence, the BoI process was lengthy and involved intensive Transpower resources. We adopted a co-operative approach so that the public could understand the purpose and nature of the NIGU Project. This was considered to both increase the prospects of us being able to ultimately carry out the works as smoothly as possible, and reduce the risk, and associated delay, of an appeal of the Board’s decision.

The delay was therefore due to factors which could not reasonably be anticipated, and which are not attributable to Transpower.[16]

3.6 Transpower’s response to the delay in the BoI process

Our engagement in the BoI process sought to minimise the delays to the BoI process. The process for obtaining regulatory approvals took substantially longer than anticipated by all parties and regulators at both the Electricity Commission and BoI stages. By the time of the BoI’s approval in September 2009, three years had elapsed since the amended GUP was submitted to the Electricity Commission for approval.

3.7 Project implementation

Beca was engaged by Transpower in 2005 to assist in developing an implementation strategy for the NUGU Project.[17] Among other things, Beca recommending dividing the Project into three components: an overhead transmission line sub-project, an under-ground cables sub-project and a substation sub-project.

16 It is worth noting that the Resource Management Act has since been amended to streamline the Board of Inquiry process for projects of national significance.

17 Beca, Implementation Strategy: North Island 400kV Grid Upgrade, July 2005 – supporting document 9.1

Evans & Peck independently reviewed this strategy, concluding it was sound.[18] Evans & Peck recommended some form of relationship contracting principles be incorporated into the commercial framework for the overhead transmission line works. This was to mitigate the delivery risks it identified as being beyond the control of either Transpower or the contractor and which cause time delays which would impact on successful completion. These factors were principally uncertainty about land access, consenting process and regulatory approval.

As discussed more fully in section 8, Transpower agreed with this approach and entered into an alliance agreement for the overhead transmission line works.

3.8 Construction and labour contracts and arrangements made

The main contracts we entered into were:

- a Project Alliance Agreement (**PAA**) with BBUGL relating to the construction of the overhead transmission line (this is discussed in more detail in section 0);
- a single supplier contract with Taihan New Zealand Limited involving a joint venture between Taihan Electric Wire Co Ltd and LS Cable Limited (**Taihan**) to design, supply, install and commission underground cables between Brownhill and our Pakuranga substation (discussed in more detail in section 9);[19]
- easement agreements with landowners (these are discussed in more detail in section 1);
- a number of discrete contracts for design, equipment supply and construction of the substation sub-projects.

The Project Closeout Reports accompanying this application outline the material contracts entered into as part of the NIGU Project and summarise actual outcomes against the initial cost estimates.

3.9 Project management processes

3.9.1 NIGU Project Plan

In the GUP submitted to the Electricity Commission, Transpower:

- Agreed to conduct for the Transpower Board independent periodic audits of its project management, procurement and commercial processes to demonstrate that cost controls are in place, with a demonstration of the process of business improvement in response to any issues identified;
- Agreed to report regularly to the Transpower Board on progress against both expected costs and cost with contingencies, and reasons for any divergence;
- Acknowledged that to manage the project risk it is essential that a high degree of quality assurance is applied in planning, design, manufacture, commissioning, testing and maintenance activities in accordance with good electricity industry practice.

18 Evans & Peck, Project Implementation Strategy Review, August 2005 – supporting document 9.2

19 This included a joint venture contract between Taihan and LS Cable Limited for supply of the cable.

Transpower adopted a Project Plan for the NIGU Project in May 2007. This Project Plan was later revised, with version 4 being issued in February 2009. A copy of the Project Plan is included as Attachment 9.3 in the supporting documentation included with this application.

The overall NIGU Project works were divided into 11 separate, but related sub-projects for project management and cost control purposes. Clear accountabilities were established, promoting ownership and responsibility for the deliverables for each project.

We also adopted a detailed Programme Management Plan (**PMP**) in August 2009. The PMP provided more detail on project implementation, including project costs and time constraints, organisational structure (including defined roles and responsibilities), specifics of project planning and management, and financial, quality and programme aspects of the NIGU Project. The PMP also included a general procurement policy for all works associated with NIGU.

The PMP was reviewed and updated from time to time. A copy of the PMP is included as Attachment 9.4 in the supporting documentation included with this application.

3.9.2 Independent review of project management processes

We commissioned IQANZ (Independent Quality Assurance New Zealand) to conduct three independent reviews of the NIGU Project:

- first, a Baseline Health Check Review was undertaken in September 2009
- second, a Follow-up Health Check Review in March 2012
- third, another Follow-up Health Check Review and Close-out Review completed in August 2013.

Copies of these IQANZ reports are included with this application as supporting documents 11.1 to 11.3.

While these reports identified areas for improvement, overall they commended the project management procedures and scope control mechanisms that were put in place.

In its September 2009 report, IQANZ made the following observations:[20]

- "The programme has established a strong governance framework and has developed a novel approach to help minimise the uncertainty/timing risk with an existing joint venture company (between Balfour Beatty and United Group) in a pain/gain share relationship"
- "An effective project management environment has been established at all levels (project, programme, sub-project and Alliance) with a focus on effective management of the stakeholder relationships and legal aspects of the project."

In its report of August 2013, IQANZ observed that:

20 IQANZ, Transpower – North Island Grid Upgrade Project: Health Check Review, September 2009, p 3 –supporting document 11.1

- "Since our last review a strong commissioning plan was put in place, and project controls were strengthened"
- "There were strong controls around expenditure and cost reimbursement to the Alliance, but weak processes around cost forecasting and provisioning for unknowns, until further expertise was injected into the project in 2011".[21]

3.9.3 Changes to project management processes

Where there were some inadequacies identified in the project management process, we acted to mitigate these and to continually improve the management processes throughout the project.

For example, we experienced some difficulty with executing governance controls and processes early in the project for the Alliance, and this meant that unresolved claims were allowed to accumulate, rather than being dealt with promptly. To mitigate this, we injected further experience. We also changed the mechanism for cost forecasting to an earned value basis, ensuring adequate contingency was included to cover the risk and that adequate provisions were made for circumstances such as bad weather. Once this change was made, cost forecasts improved. In addition, general governance controls were tightened (for example meeting minutes and resolutions of ALT meetings were formally recorded).[22]

The Alliance also acted to engage efficiency experts to construct an in-depth study on construction setups and controls, which led to marked improvements in productivity. IQANZ indicated that the timely implementation of the recommendations of this productivity report demonstrated effective management of the Project.[23]

3.10 Property and access rights obtained or being sought

Obtaining necessary property rights to enable the delivery of the NIGU Project was a critical aspect of the project, both in terms of efficient implementation and cost. Property rights in respect of 318 properties along the new transmission line route were obtained through purchase of freehold titles,[24] and acquisition of easements and other property rights.

The property work stream is discussed in more detail in section 7.

3.11 Construction completed to date

The Brownhill-Whakamaru line was the last component of the NIGU Project to be commissioned, on 30 October 2012.

21 IQANZ, Transpower – North Island Grid Upgrade Project: Follow up and Close-out Health Check Review, August 2013, p 4 – supporting document 11.3.

22 IQANZ Report August 2013, p 5.

23 IQANZ Report August 2013, p 5.

24 Properties that were acquired through the purchase of freehold title had easements recorded on the title and then were sold through an open market sales process. As at the date of this application, Transpower has sold 79 properties and has 14 under offer.

The NIGU Project is now fully functioning, although there are small works still to be completed – notably, a retaining wall, limited access track remediation, some landscaping, and certain documentation.

3.12 Asset testing processes

We have conducted standard testing of the assets commissioned as part of the NIGU Project in accordance with Transpower standards, manufacturers' specifications and good electricity industry practice.

Most of the assets that have been commissioned under the project have been in service for nine months and all are reliably delivering the grid outputs in accordance with the GUP.

3.13 Safety on the NIGU Project

The safety of staff and contractors was a high priority for the project from the outset. With 426 transmission towers to be built, the construction of three substations and over 11km of double circuit high voltage underground cable to be installed, the risks to personal safety were high. A major safety incident causing permanent disablement or loss of life was considered a high risk.

High attention was paid to minimising safety risks through selection of contractors with excellent safety records and culture, good quality planning and strong leadership at all levels.

Balfour Beatty brought with it a UK approach, including a heavy emphasis on safety. The overhead line project presented significant safety risks. The works were conducted on over 400 separate sites, and involved high risk activities such as work at height, use of cranes and helicopters and travel over enormous distances.[25] The quality of planning of the works at each tower site was excellent, with "Go Packs" produced on a site by site basis, setting out all the information the crews would need to know to minimise hazards. There was a strong focus on selecting the right people to lead the site teams and the provision of training and overall leadership. Training and safety "downtime" was planned into the project and details such as proper engineering design of temporary works, lifting plans for every crane operation and fixed line fall arrest systems fitted to every tower were included.

The result was a project that had a culture of safety embedded from the start and every staff member knew that safety was a critical success factor. The project achieved an excellent safety record – over the 1.7 million man hours utilised, there were 2 lost time injuries and a Total Recordable Injury Frequency Rate (TRIFR) of 7. Importantly, there was no loss of life and no permanently disabling injury.

The experience gained from this project has helped improve our approach to safety across all of our works.

25 Over 10,000km was travelled every day at the peak of the project.

4 NIGU Project estimated and actual expenditure

4.1 Overview

Set out below is an explanation of:

- the preparation and review of the initial cost estimates for the NIGU Project;
- changes in forecast major capex during the Project; and
- the actual major capex incurred for the Project.

4.2 GUP cost estimates

The cost estimates for the NIGU project were developed for each of the 11 sub-projects individually. The estimates were developed within Transpower, but were also peer reviewed by external consultants. Each estimate had its own associated cost uncertainties (scope, price, foreign exchange, etc).

The original cost estimates for the NIGU Project are listed in Table 4-3.[26]

Table 4-3: Original NIGU Project cost estimates $2006

	Option 2: 400 kV Staged to Pakuranga		Cost ($'000)					
Year	Augmentation	Design /Procure/ Build	Investigation	Property	Proj Mgmt	Consenting	Contingency	Total
2009	350 MVAR Static compensation	7,313	-	-	585	5	1,185	9,088
2010	Decommission 110kV ARI-PAK Line	4,009	-	-	321	0	649	4,979
	Drury Switching Station	12,930		4,750	1,034	250	2,095	21,059
	Drury Switching Station-Lines	1,503			120		403	2,026
	Uprate HLE-HAM-WKM section of the OTA-WKM C line to twin Goat @ 80C	3,007		500	241	20	805	4,573
2012	2x400kV WKM-ORM ccts operated at 220kV	168,580	22,500	80,000	13,486	5500	45,152	335,219
	WHN 220 kV Substation	8,436	-	-	675	100	1,367	10,578
	WKM Sub work	2,830	-	250	226	5	459	3,770
	OTA Enabling Work	2,722	-	-	218	0	441	3,381
	OTA Subs Work	4,176	-	-	334	5	677	5,192
	2x220kV ORM-PAK cables	90,529	-	3,863	7,242	400	14,666	116,700
	Cable Termination at ORM	2,600	-	7,100	208	250	562	10,719
	220kV substation at PAK	45,880	-	-	3,670	250	7,433	57,233
	Convert OTA-PAK 110kV ccts to 220kV	501	-	-	40	5	134	680

$509,169

Total **$585,197**

26 These are an excerpt from Attachment F, Costing Report of the NIGU Proposal – supporting document 1.7

These numbers include a scope contingency, but not price contingency, exchange rate variation, nor Interest During Construction (**IDC**).

The following tables are excerpts from the GUP and show the same numbers, but grouped differently:

Table 4-4: Original NIGU cost estimates

Category	Item	Estimated Cost $m (2006)	Estimated Cost including Contingencies $m (2006)
Investigations	Preliminary engineering, environmental and property work.	22	22
Property	Acquisition of property rights	96	96
Environmental	Acquisition of designations and resource consents.	7	7
Transmission Works	2x400kV circuits from Whakamaru to a transition station in the vicinity of the South Auckland urban boundary operated at 220kV	168	210
	Other Lines Works	6	7
	Substation Works	87	101
	Cable	91	104
Dismantling	Arapuni to Pakuranga Line	4	5
Project Management		28	33
Total		**509**	**585**

This cost estimate was then converted into a commissioning year estimate ($2011), by adding financing costs (IDC) and inflation. This is shown in Table 4-5:

Table 4-5: Original NIGU cost estimates, commissioning year dollars

Category	Cost $m (2006)	Contingencies	Exchange Rate Variation	Interest During Construction	Fully Adjusted Cost $m (2006)	Inflation	Fully Adjusted Cost $m (2011)
Investigations	22	0	0	0	22	5	27
Property	96	0	0	12	108	20	128
Environmental	7	0	0	2	9	2	11
Lines	174	43	0	29	246	44	290
Substations	87	13	0	4	104	18	122
Cable	91	13	0	8	112	21	133
Decommissioning	4	1	0	0	5	1	6
Project Management	28	6	0	7	41	6	47
Total	509	76	0	62	647	117	764

Although we were not required to calculate a P50 for the purposes of the GUP and/or complying with the Electricity Governance Rules (**EGRs**) applicable at the time, the commissioning year cost estimate above, of $764 million, is close to a P50 and, for the purposes of this application, serves that purpose.

We note that this would have been close to the P50 using the calculation approach at the time, but for reasons discussed in more detail below is significantly lower than the P50 we would calculate now.

We also note that, despite cost estimators best attempts on large infrastructure projects such as the NIGU Project, such projects are rarely delivered for costs close to the original P50. The median cost for such projects is probably closer to our P90, because unknowns are not usually reflected well enough in the economic modelling. The detailed design required to produce cost estimates with relatively low uncertainties would be prohibitive – timing-wise and cost-wise – yet managers and regulators would baulk at the true uncertainty in initial cost estimates, so the tendency is for cost estimates to underestimate uncertainty.

For the NIGU Project we were inexperienced at cost estimating for large, complex projects and so we under-forecast the uncertainty in the cost estimates. This is apparent in the P50 estimate of $764 million, which we now believe was unrealistic.

4.2.1 Assessment of GUP estimates

For later GUPs submitted to the Electricity Commission and for Major Capex Proposals submitted to the Commerce Commission under the new Capex IM, we provide a detailed breakdown of our cost estimates. These are checked and verified by the regulator as being reasonable or otherwise.

For the NIGU Project, the Electricity Commission took a different approach. Rather than consider our cost estimates in detail, the Electricity Commission engaged external parties (including Parsons Brinckerhoff Associates (**PBA**)) to design at a high level and cost a 400 kV line themselves and they compared those outcomes with our proposal.[27] The Electricity Commission

27 The Electricity Commission engaged Parsons Brinckerhoff Associates to assess the capital costs for each item of transmission equipment identified by Transpower in the GUP. See North Island Grid Upgrade Project: Review of

observed that the PBA capital costs estimates and Transpower's estimates were largely consistent and within reasonable accuracy bounds in respect of each other. In light of this, the Electricity Commission relied on the capital cost estimates provided by Transpower in approving the GUP.[28]

4.2.2 Calculation of the NIGU Project maximum capex allowance

Being the first project to be submitted under the newly developed EGRs, it was not clear how to establish a MCA for the NIGU Project. Following discussion, we agreed with the Electricity Commission that we should apply for a MCA which represented a P90 level for the overall programme of works (i.e. an amount with only a 10% probability of being exceeded).

Calculating a P90 for such a programme of works required assumptions to be made about how related the costs are between each of the sub-projects. Were the projects related, such that as a cost uncertainty in one project moves the costs of another project also move with it? Or were the projects not related, with the costs moving independently of each other?

It was clear that, for instance, the costs of installing the static reactive compensation were unrelated to the cost of building the new transmission line. These two projects are independent and the risks are quite separate. It was eventually agreed to assume that all of the NIGU sub-projects were independent of each other.

An implication of this assumption was that it would not be possible to arithmetically calculate a P90 for the overall NIGU Project. A sampling technique would be required and Monte Carlo sampling was chosen, being a relatively well accepted approach. Using Monte Carlo analysis, an overall P90 of $824 million in $2011 was calculated (as shown in Table 4-6). This amount was ultimately approved by the Electricity Commission as the MCA for the NIGU Project.

Capital Cost Estimates for Transpower's Amended Proposal of October 2006, Parsons Brinckerhoff Associates, 15 December 2006 –s supporting document 2.1

28 Electricity Commission, Reasons for Decision set out in Notice of Intention to Approve Transpower's North Island Grid Upgrade Proposal, 23 February 2007, para 7.3.20 – supporting document 3.3. See also Electricity Commission, Final Decision on Transpower's North Island Grid Upgrade Proposal, 5 July 2007, para 4.4.3 – supporting document 3.4.

Table 4-6: Original NIGU cost estimates, maximum capex allowance

Category	Cost $m (2006)	Contingencies	Exchange Rate Variation	Interest During Construction	90% Cost Limit $m (2006)	Inflation	90% Cost Limit $m (2011)
Investigations	22	0	0	0	22	5	27
Property	96	0	0	13	109	23	132
Environmental	7	0	0	2	9	2	11
Lines	174	46	14	30	264	52	316
Substations	87	18	4	5	114	22	136
Cable	91	16	3	9	119	27	146
Decommissioning	4	1	0	0	5	1	6
Project Management	28	6	0	7	41	9	50
Total	509	87	21	66	683	141	824

With the benefit of perfect hindsight, the amount of contingency built into the original approval amount was too small. The P50 of $764 million included a scope allowance of 15% over all the NIGU projects. This has proved to be unrealistic, given the early stage of design process and incomplete information on geotechnical and other site-specific conditions along the line route on which the cost estimates were based, and should have been higher.

Additionally, the Monte Carlo analysis used to generate the P90 calculation ignored the interdependent nature of some of the sub-projects and we now believe this could have been better explained and factored for. The NIGU sub-projects were not all independent of each other, as originally assumed. The most obvious example of this is that building the new 400 kV capable transmission line is highly dependent on the separate project of purchasing easements for the new line. Had this correlation been recognised early enough in calculating the P90, it would have had a significant effect on the calculation and the MCA. We estimate that if the 400 kV transmission line cost and associated easement cost had been assumed to be correlated, the P90 estimate from Monte Carlo analysis would have been $860 million using the original property cost estimates, and as much as $930 million if the unforeseen property costs discussed later in this application are included.

4.3 Post-GUP budgeting

The NIGU Project Director allocated $824 million across all sub-projects, allocating more contingency to those projects which were less certain. The result of that exercise established the first set of working budgets for the NIGU project, as shown in Table 4-5.

Table 4-7: NIGU cost estimates, reallocated but within MCA

TRANSPOWER DETAILED BREAKDOWN	$2006			$2011
$'000s	BASE COST	CONTINGENCY	TOTAL	MCA
LINES				
OTA-WKM 400kV	168,580	41,808	210,388	307,873
NIGUP Lines Property	80,000	0	80,000	112,863
Lines Project management	13,486	2,889	16,375	25,804
NIGUP Consent	6,515	0	6,515	10,642
			0	
ARI-PAK Line	4,009	601	4,610	5,944
			0	
ARI-PAK Project management	321	69	390	523
OTA-PAK Upgrade	501	124	625	832
OTA-PAK Upgrade Project management	40	9	49	65
CABLE				
BHL-PAK Cable	90,529	13,579	104,108	146,000
NIGUP Cables Property	3,863	0	3,863	4,535
Cables Project management	7,242	1,551	8,793	11,803
SUBSTATIONS				
PAK GIS	29,880	4,482	34,362	24,656
PAK AIS	16,000	2,400	18,400	46,786
BHL	2,600	520	3,120	4,181
OTA	4,176	626	4,802	6,435
OTA Enabling	2,722	408	3,130	4,194
WHN	8,436	1,265	9,701	12,999
WKM	2,830	425	3,255	4,362
Substations Project Management	5,332	1,142	6,474	8,690
NIGUP subs property	7,350	0	7,350	8,324
INVESTIGATIONS				
NIGUP Investigations	22,000	0	22,000	27,000
DEFERRAL PROJECTS				
Drury	12,929	1,939	14,868	20,732
Drury Sub Project Management	1,034	180	1,214	1,624
Drury Property	4,750	0	4,750	5,661
Drury Sub Consenting	250	0	250	325
Drury Lines	1,503	225	1,728	2,300
Drury Line Project management	120	21	141	188
OTA-WKM C	3,007	746	3,753	4,995
OTA-WKM C Property	500		500	592
OTA-WKM C Project Management	241	42	283	378
OTA-WKM C Consenting	20	0	20	26
OTA Reactive	7,313	1,097	8,410	11,656
OTA Reactive Project Management	585	102	687	919
OTA Reactive Consenting	5	0	5	7
TOTALS	**508,669**	**76,250**	**584,919**	**823,914**

This allocation is used in this application as the primary basis (latter developed project budgets are included in some instances) for evaluating the financial performance of individual projects, with the aggregation as shown in Table 4-6. This aggregation was also used for wider communications about the NIGU Project and budget reporting, particularly to the Transpower Board, as shown in Table 4-7.

Table 4-6: NIGU cost estimates, reallocated for Board reporting

TRANSPOWER DETAILED BREAKDOWN	$2011						
$'000s	MCA	LINES	PROPERTY	CABLE	SUBSTATIONS	INVESTIGATIONS	DEFERRAL
LINES							
OTA-WKM 400kV	307,873	307,873					
NIGUP Lines Property	112,863		112,863				
Lines Project management	25,804	25,804					
NIGUP Consent	10,642					10,642	
ARI-PAK Line	5,944	5,944					
ARI-PAK Project management	523	523					
OTA-PAK Upgrade	832				832		
OTA-PAK Upgrade Project management	65					65	
CABLE							
BHL-PAK Cable	146,000			146,000			
NIGUP Cables Property	4,535		4,535				
Cables Project management	11,803			11,803			
SUBSTATIONS							
PAK GIS	24,656				24,656		
PAK AIS	46,786				46,786		
BHL	4,181				4,181		
OTA	6,435				6,435		
OTA Enabling	4,194				4,194		
WHN	12,999				12,999		
WKM	4,362				4,362		
Substations Project Management	8,690				8,690		
NIGUP subs property	8,324		8,324				
INVESTIGATIONS							
NIGUP Investigations	27,000					27,000	
DEFERRAL PROJECTS							
Drury	20,732						20,732
Drury Sub Project Management	1,624						1,624
Drury Property	5,661						5,661
Drury Sub Consenting	325						325
Drury Lines	2,300						2,300
Drury Line Project management	188						188
OTA-WKM C	4,995						4,995
OTA-WKM C Property	592						592
OTA-WKM C Project Management	378						378
OTA-WKM C Consenting	26						26
OTA Reactive	11,656						11,656
OTA Reactive Project Management	919						919
OTA Reactive Consenting	7					7	
TOTALS	**823,914**	**340,144**	**125,722**	**157,803**	**113,134**	**37,713**	**49,397**

Table 4-7: NIGU cost estimate breakdown, used for Transpower Board and project reporting

Sub-projects	GUP Budget	
	P50 $m	P90 $m
Transmission Line	313	340
Property	122	126
Cables	144	158
Deferral Projects	45	49
Investigations and environmental	38	38
Substations	102	113
Total	764	824

4.3.1 Reallocation of cost estimates

As the NIGU Project progressed and more detailed cost estimates were developed, contingency was moved from sub-projects that were forecast to cost less than originally estimated to sub-projects that were subsequently forecast to cost more.

An example is that the original cost estimate included the cost of developing a Gas Insulated Substation (GIS) at Pakuranga. The BoI accepted our contention that a GIS was not necessary at Pakuranga and a lower cost Air Insulated Substation (AIS) could be built. As the BoI had increased the costs of the BHL-WKM transmission line in some areas, the extra $25 million to cover the GIS cost, was reallocated to the transmission line.

4.3.2 June 2011 reforecast

Once construction activities commenced following the conclusion of the BoI process, costs across the NIGU Project as a whole were monitored regularly.

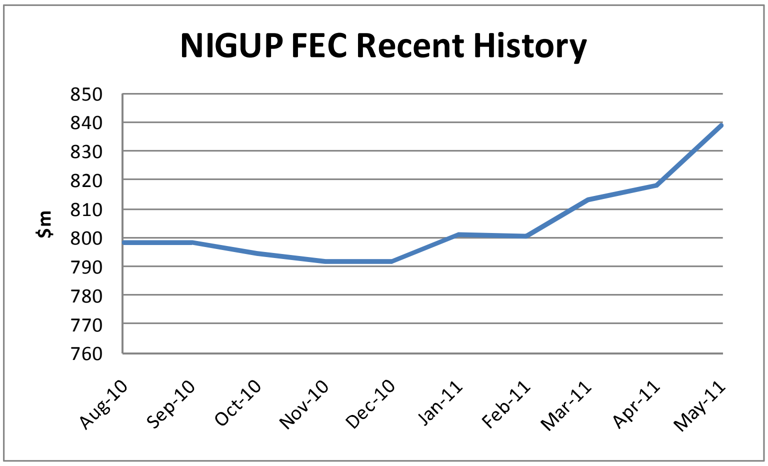
Factors such as worse than anticipated ground conditions (hence greater tower foundation requirements), on-site complications caused by tomos,[29] and initially lower than forecast tower erection productivity all contributed to an increasing cost for the line. In contrast, cables, substation work and the deferral project works were all progressing satisfactorily and within budget estimates. NIGU Project costs - when taken as a whole – tracked initially within the MCA for the NIGU Project.

However, by early 2011 it was apparent that the increased overhead transmission line costs, plus the higher property costs being incurred, meant that the cost for the overall NIGU Project would exceed the MCA of $824 million.

This is shown in Figure 4-2 below, being the NIGU project forecast end cost over time, based on costs incurred to May 2011.

29 A tomo is the formation of a subterranean natural void, which was not foreseen, and which affected foundations due to the light, uncompacted volcanic ash soils in the southern end of the new transmission line. These tomos were large and would have severely affected tower stability if not addressed, which was done by filling them with large quantities of grout.

Figure 4-2 NIGU project forecast end cost over time, to May 2011



The Alliance investigated where savings could be made in building the new transmission line. This is discussed in more detail in section 8.

The delayed start to construction work for the overhead transmission line (due to the protracted BoI process) also meant that the expected commissioning date for the new transmission line was delayed from October 2011 to May 2012.

Transpower Board approval was sought and obtained in June 2011 for expenditure up to $860 million, based on revised estimates.

4.3.3 May 2012 reforecast

In May 2012, the NIGU Project was forecast to cost up to $894 million. The increase in costs related partly to higher property costs, but mostly to higher transmission line construction costs, in particular, arising from imperfect cost estimating and forecasting by the Alliance. The expected commissioning date for the new transmission line was also further delayed from July 2012 to October 2012.

Transpower Board approval was sought and obtained in May 2012, for expenditure up to $894 million, based on the revised estimate in Table 4-8 below.

Table 4-8: Revised NIGU cost estimate, May 2012

Sub-projects	2006 Board/Electricity Commission Approval $m	June 2011 Board Approved $m	May 2012 Board Approval $m	Variance to October 2006 MCA
Transmission Line	340	380	402	62
Property	126	165	175	49
Cables	158	151	153	(5)
Deferral Projects	49	39	39	(10)
Project Management, investigations and environmental	38	39	37	(1)
Substations	113	77	80	(33)
Additional IDC (May to September 2012)		8	incl above	
Management Reserve			8	8
Total	**824**	**860**	**894**	**70**

4.4 Forecast end cost of NIGU Project

Table 4- below shows the actual costs to 31 August 2013 and current forecast end cost of the NIGU Project. The costs we are seeking approval to recover in this application are based on the numbers in this table.

Table 4-9: NIGU Project - actual costs to 31 August 2013 and Forecast End Cost, $000's

Project	Sub-project	Actuals	IDC	Forecast	Forecast End Cost
BHL-WKM line		368,166	43,133	-12,494	398,805
BHL-WKM property		153,804	7,496	5,060	166,361
BHL-WKM Cables		136,653	10,830	2,898	150,382
Substations	BHL	8,250	586	38	8,874
	OTA	13,274	765	0	14,039
	PAK	29,013	1,622	452	31,096
	WKM	16,662	1,002	661	18,326
	STN-general	5,886	2,080	0	7,970
	OTA-WKM equip	60	13	0	74
Drury	DRY	13,465	275	0	13,740
	Drury property	5,662	7	0	5,670
	Drury INV	492	100	0	592
	Drury lines	283	30	0	314
OTA-WKM C		6,996	437	0	7,434
	Investigation	251	62	0	313
Reactive Support	OTA 110 kV cap	5,748	72	0	5,820
	Investigation	142	22	0	165
	PEN 110 kV cap	2,552	42	0	2,595
	HEP 110 kV cap	1,583	27	0	1,610
Other Property	BHL_OTA route	6,242	106	1,640	7,988
	BHL-PAK route	2,019	166	0	2,185
	Other property	10,882	16	0	10,899
PM,Environ,Invest		29,370	8,466	751	38,587
		$817,475	**$77,360**	**-$993**	**$893,842**

The difference between the forecast end cost of the NIGU Project and the original MCA is $69.8 million.

5 Overview of expenditure by sub-project

The Commerce Commission indicated in its Decision on the Otahuhu Substation Diversity Project Major Capex Allowance Amendment, that it is relevant to examine all costs incurred throughout the Project, not just those components which exceeded the approved budget.[30]

Accordingly, we set out below a discussion of the works and expenditure on all of the sub-projects comprising the NIGU Project, being:

- Substations (section 6)
- Property (section 7)
- New 400 kV overhead transmission line (section 8)
- Underground cables (section 9)
- Deferral projects (section 10)
- Investigation and environmental consenting (section 11).

Actual expenditure is compared against the GUP P90 estimate for each sub-project. The GUP P90 estimate is the estimate set out earlier in Table 4-7, which was used as the basis for Transpower Board and project reporting.

As discussed more fully below, most sub-projects came in close to budget, while property and the overhead transmission line works exceeded the initial forecast costs.

30 Commerce Commission, Decision on the Otahuhu Substation Diversity Project Major Capex Allowance Amendment, [2013] NZCC 8, para B23 – supporting document 3.7.

6 Substation works

($80m expenditure against GUP P90 estimate of $113m)

6.1 Summary

Table 6-8: Substation costs

Date	Description	Amount	Variance
October 2006	GUP estimate (P90)	$113.1m	-
Various	Approved PAD's (incl PAK GIS)	$90.1m	
August 2013	Forecast End Cost	$80.3m	-$32.8m

The substation programme of works for the NIGU Project comprised works at the following substations:

- Brownhill;
- Pakuranga;
- Otahuhu; and
- Whakamaru.[31]

Transpower completed all the individual projects within the substations programme of works on time and within the overall GUP P90 allocation. We consider all expenditure on the substation programme of works was reasonable and efficiently incurred.

Conceptual designs for Whakamaru B and Brownhill were developed for the eventual 220/400 kV substations at those sites to enable a new 220 kV underground cable to run from Brownhill to Otahuhu in the future and also 400 kV operation of the Whakamaru to Brownhill overhead transmission line.

We obtained designation and resource consents for all substation sites and all required property rights. Designations and resource consents included for upgrading the Whakamaru to Brownhill overhead transmission line to 400 kV operations in the future – in line with the approved GUP.

We obtained environmental approvals to install an air insulated substation (AIS) instead of gas insulated substation (GIS) at Pakuranga which saved significant cost. The amount in the GUP for the GIS was the incremental cost above the construction of an AIS substation. This adjustment to the programme is an example of how we continually chose the most cost effective solution where possible, even though these decisions were complex and carried some risk.

We discuss below the approach to the substation works as a whole, before explaining each of the substation projects individually.

31 An extension was built near the existing Whakamaru substation to be known as Whakamaru B or Whakamaru North.

6.1.1 The planning stages of the substation programme of works

The substation programme of works included the following steps:

- preparation of drawings and technical specifications;
- development of project procurement plans;
- preparation of the substation construction tender specifications;
- tendering, negotiating and awarding the substation construction contracts;
- preparation of the substation plant and equipment procurement specifications; and
- tendering, negotiating and awarding the substation plant and equipment procurement contracts.

A workshop early in the project concluded that the NIGU Project substations works were generally typical 220 kV "business as usual" design and construction works and standard Transpower business processes were appropriate. It was therefore decided that the substation works would be carried out using a solution study / detailed design two-step design process involving design consultants already approved to carry out Transpower works. Transpower also elected to procure key electrical items itself and to directly engage and manage earthworks, civil works, buildings and installation contracts.

6.1.2 Conceptual designs

Conceptual designs were prepared for all parts of the approved GUP. The conceptual designs were developed sufficiently to establish the substation configurations and definition of the physical structures and layouts for all stages of the approved GUP. Detailed cost estimates were also prepared during the conceptual design stage.

This was done to enable the Notices of Requirement for designations and resource consents to be submitted for consideration by the BOI. The Notices of Requirement were supported by geotechnical and noise assessment information as appropriate.

6.1.3 Solution studies and detailed designs

For the solution studies, a registration of interest document was sent to three of Transpower's preferred design consultants and also to SKM, who were acting as Transpower's engineer on the transmission line project. A request for proposal was subsequently sent to Beca and AECOM. The Pakuranga 220 kV and Whakamaru A and B substations were complete substations involving all disciplines and we considered that only those two larger preferred consultants (Beca and AECOM) had the ability to carry out the complete scope of work in-house without impacting on their other Transpower work.

Beca and AECOM were engaged to carry out design work at Whakamaru and Pakuranga respectively. After the preparation of solution studies each consultant, now thoroughly familiar with the substation on which they were working, prepared a detailed design. This afforded the opportunity to develop good working relationships with the designers that extended for the duration of the complete project and enabled the designers to answer construction phase queries and monitor quality as required.

6.1.4 Management of costs

Costs for the substation works were closely managed by Transpower's internal Capital Works Programme Group who monitored delivery against the project approval documents (**PAD**) prepared for each substation project.[32]

Following extensive review by project participants, PADs were issued and approved as follows:

Table 6-2: List of substation PADs($ million)

PAD No	PAD Description	GUP P90	PAD approved maximum	PAD Commissioning Date
SG	NIGUP Substations General	$8.7	$7.9	NA
01	Pakuranga 220, plus works at Otahuhu-Pakuranga, Penrose, Arapuni	$47.6	$34.8	October 2011
03	Otahuhu 220 kV (incl OTA Enabling Works)	$10.6	$10.3	October 2011
04	Brownhill cable transition station	$4.2	$14.6	March 2012
05	Whakamaru substations and tie-line	$17.4	$21.5	March 2012
SA	Pakuranga GIS	$24.7	NA	Not Required
	Total	**$113.1**	**$90.1**	

The PAD for the Pakuranga project was lower than the GUP budget due to a better scoped cost estimate coming out of the solution study phase. A saving was made as an Air Insulated Substation (AIS) was approved by the BOI as an appropriate solution for the Pakuranga substation, instead of the initially envisaged Gas Insulated Substation (GIS).

The PAD for the Brownhill cable transition station project was higher than the GUP budget because the full substation platform area suitable for installation of 400/220 kV transformers and associated GIS substation works in the future was constructed.

The PADs for the Whakamaru B and Whakamaru projects were higher than the GUP budget because a more accurate cost estimate came out of the solution study phase. For example, the PAD took account of the the results of full geotechnical investigations (which occurred following the calculation of the GUP budgets).

In addition, we:

- engaged external contract management and engineering support to assist in the project management process; and
- used SKM Australia to peer review the substation cost estimates.

32 Individual PADs were prepared for the NIGUP Substation Works at Pakuranga, Otahuhu, Brownhill, Whakamaru, Whakamaru North and the Whakamaru Tie Line.

Our past experience in managing large substation projects was critical to the successful resourcing of this programme of works.

6.2 Financial performance of the substation works

6.2.1 Substations general

Table 6-3: Substations general costs

Date	Description	Amount	Variance
October 2006	GUP estimate (P90)	$8.7m	-
Date	PAD	$7.9m	-
July 2013	Forecast End Cost	$8.0m	-$0.7m

Overview of works

The scope of the works for this project included:

- Assisting with NIGU substations input to GUP;
- Responding to Electricity Commission inquiries;
- Developing conceptual designs for the all substations of the approved GUP including detailed cost estimates and enable Notice of Requirement for a designation and resource consent;
- Presentation of evidence to the BOI;
- Integration of a customer investment contract into the contract document for Transformers and 33 kV outdoor to indoor conversion;
- Preparation of a Project Management Plan for Substations;
- Preparation of a contracting strategy for Substations;
- Preparation of PADs for Substations;
- Any other design, investigations and management support for Substations section the BOI.

Contract award process

Both designers for the Whakamaru and Pakuranga substations were selected on the basis of their prices and their capability to handle a design of the size envisaged. This meant that only two designers, AECOM and Beca, were pre-selected. Transpower kept the tender list confidential and both parties tendered for both contracts.

Project Management

The Substations General sub-project comprised the function and cost of the management of the Substations Programme whereas management of the individual sites and the work required to implement the construction at the individual sites was charged to the specific sub-project (Pakuranga, Brownhill, Otahuhu or Whakamaru, as appropriate).

Project performance – Substations General

Although a PAD was produced for the Substations General sub-project, there is no break-down of cost estimates to compare the actual costs against. $0.2 million was added to an initial budget amount of $7.7 million to give a total of $7.9 million shown above.

Table 6-4: Substations general cost breakdown

Cost Area	Actual Cost	Notes
General	$0.7m	Mostly travel costs
Employee Time	$1.9m	Internal employee time across all disciplines
A & G Expenses	$0.1	Domestic and International travel costs
Substation Design	$3.2m	Concept Designs for PAK, OTA, WKM A & B and Detailed Design ($1.3m) for WKM[33]
Project Management Support	$0.9m	Misc Station design to support BOI
Investigations and Legal	$0.1m	
Stations Design	$0.5m	Geotech, noise, transport, earthing and resistivity investigations
Designation	$0.6m	Internal and external consultants for BOI process

6.2.2 Brownhill transition station

Table 6-5: Brownhill transition station costs

Date	Description	Amount	Variance
October 2006	GUP estimate (P90)	$4.2m	-
August 2009	PAD	$14.6m	-
August 2013	Forecast End Cost	$8.8m	$4.6m

Overview of works

The Brownhill cable transition station project involved the design, procurement and construction of a transition station at Brownhill Road to transition from overhead line to underground cable. It included an access road from the site boundary.

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33 The expenditure for the detailed design of Whakamaru substation ($1.3 million) should have been allocated to the Whakamaru A, B and Tie Line project. Given that this has no impact on actual cost for the NIGU Project, being simply a matter of accounting treatment of a properly incurred NIGU Project cost, we have not adjusted the budget and actual cost figures as presented to the Commission. Accordingly, forecast end cost for the Substations General sub-project should, in substance, be $6.7 million.

As part of its Notice of Requirement, Transpower proposed two options for development. They were:

- For an AIS option, some 10,500m^3 of earthworks in Stage 1 for the transition station platform and access road (the maximum cut height is 8 metres and fill height is less than 5m) and Stage 2 of some 280,000m^3 of earthworks (over 2 construction seasons from 2020 onwards, the max cut is 20m and max fill is 12m).
- For a GIS option, the entire platform, including the area for the transition station would be constructed at the start of project. This would require a cut of 65,000m^3 for the platform and access road.

During the BOI, Transpower decided, following discussions with Brownhill Road residents and analysis of the comparative costs, that the substation would be built with GIS technology. The final report of the BOI confirmed that a GIS substation should be built.[34] We therefore completed the earthworks for the ultimate development of the Brownhill substation on this basis.

The project was delivered on time and although costs were within the PAD budget, they exceeded the GUP budget due to the significant change in scope building a GIS.

Contract award process

The design contract was selectively sourced to Beca. The earthworks contract was awarded after a contestable tender process involving five companies. This contract included a range of works such as excavation, filling, drainage, environmental, visual mitigation and stream restoration.

Some cost savings were achieved because we were able to take advantage of a very competitive civil works environment due to low volumes of construction projects in the Auckland region at the time.

Project Management

These works were project managed in accordance with the PMP for the NIGU project and standard Transpower project management processes.

All project deliverables were satisfactorily provided in accordance with the project scope, although some additional visual mitigation was required to meet the designation and resource consent conditions, for the benefit of neighbouring properties.

Interface arrangements allowed effective co-ordination between transmission lines, underground cabling and earthworks contractors working in the vicinity of the Brownhill substation. Transpower ensured that agreement was reached early on as to the specific demarcation points for each contractor's areas of responsibility.

The Project Manager and Environmental Manager actively engaged with those residents neighbouring the substation. These neighbours were vocal in their opposition to the location of the transition/sub-station, especially as the lifestyle properties at the end of Brownhill Road overlooked

34 Report and Decision of the Board of Inquiry into the Upper North Island Grid Upgrade Project, Appendix E – Brownhill Substation Conditions - supporting document 8.3.7.

the site. We initiated public meetings, which were effective in ensuring the cooperation of the local community and affected property owners.

The works were delivered within the required timeframe and to the required standard.

Project performance - earthworks

The final end-cost for earthworks was $4.8 million.

This represents an increase of $723k on the awarded earth works contract price. However, overall this is significantly less than the PAD estimate. The civil works, environmental, earth grid and communications had a budget of $9.9 million but ultimately incurred only $6.9 million.

The following factors impacted on the delivery (and cost) of the works.

- Earthworks were unable to be completed in the first season largely due to the type of materials found on site and inclement weather. The majority of earthworks needed to be completed before the transition station was constructed, because the transition station area is largely fill.
- A sediment control pond located in the same space as the transition station needed to be reduced in size to allow for the construction of the termination area. The location and size of the sediment control pond at the lowest point of the site meant that a significant amount of the works had to be stabilised and completed before the pond could be reduced in size.
- A significant amount was spent on landscaping including the moving of a stream. The stream movement was necessary to gain resource consents and the additional landscaping and slope stabilisation works were required to meet the designation conditions.
- Additional geotechnical remedial works were required at a cost of $99k, aggregate had to be added to the base of the gully at a cost of $76k, and cut slopes had to be stabilised to prevent collapse.
- Additional work was also required for the piling within the transition station. This was to mitigate against timing constraints on the overhead lines component of the work, so that the substation could be completed prior to the lines arriving on site. This additional work cost $241k.
- The contractor used air drying techniques to bring the fill material up to moisture content specification, rather than relying solely on liming. This saved $631k.
- Some cost savings were achieved by re-designing the future substation platform to take account of extra fill material on side.

Project performance - Brownhill works as a whole

The Brownhill cable transition station works were significantly less than the PAD budget but exceeded the GUP P90 budget.

Table 6-6: Brownhill transition station cost savings

Cost saving area	Amount saved versus PAD
Cable terminations	$0.7m
Civil, Environmental, Earth grid and Communications	$3.1m
Protection	$0.3m
Building	-$0.2m
Primary Plant.	$0.2m
Capitalised Interest	$0.4m
Contingency	$1.3m , not required

These cost savings were able to achieved by:

- Reducing the scope of cable terminations works in consultation with the overhead line and cable sub-projects, resulting in a saving of $225k;[35]
- Relying on less lime drying, which also reduced the quantity of fencing;
- simplifying protection to only a single relay for each circuit, resulting in a cost saving of $274k; and
- ensuring that the contractor was proactive in ensuring cost-efficient methods were employed.

We spent more than was originally budgeted for environmental consenting and landscaping.[36] Environmental consenting and landscaping costs were significantly underestimated during the preparation of the budget because a significant number of conditions were added to the designation and resource consents (including for slope stabilisation). In addition, Transpower has agreed to contribute to the restoration of the surrounding land to a reasonable standard for sustainable farming.

6.2.3 Pakuranga substation

Table 6-7: Pakuranga substation costs

Date	Description	Amount	Variance
October 2006	GUP estimate (P90)	$47.6m	-
December 2008	PAD	$34.8m	
August 2013	Forecast End Cost	$31.1m	-$16.5m

35 It was considered more logical that the underground cable contractor install the cable stands and the lines crews install the terminating gantries.

36 Actual costs were $1,130,201 compared to an environmental consenting budget of $175,000.

Overview of works

The Pakuranga 220 kV substation is an AIS switchyard, constructed as a conventional breaker and half layout.

Work at the Pakuranga substation included the:

- construction of a new 220 kV substation;
- upgrade of the Otahuhu to Pakuranga transmission line to 220 kV operation;
- development of the platform for a 220 kV breaker and half substation;
- preparation for the future connection of two Brownhill Road circuits and two future 220 kV Penrose circuits; and
- construction of a control room.

The project came in under the GUP budget, largely because the preferred technology option ended up being an AIS switchyard which cost an estimated $16.6 million less than the equivalent GIS switchyard budgeted for in the GUP. While the Pakuranga substation works were completed within the Electricity Commission approved budget, individual components of the Pakuranga substation did end up costing more than the allocation in the detailed PAD budget.

The project experienced some delays due to:

- the cable route being longer than initially anticipated;
- poor weather in the second earthworks period; and
- the impact of the Rugby World Cup.

Weather played a significant role in the second year of earthworks. It delayed commencement of the buildings and foundations contract and this had a knock on effect for the rest of the works that was not recoverable.

The commissioning date was delayed until after the Rugby World Cup, consistent with a nation-wide focus on reducing grid operations involving risk. This resulted in a five month delay to the original commissioning date.

Contract award process

Transpower ran a contestable tender process for most of the Pakuranga substation works.

The table below sets out the suppliers for the project and services provided, including the type of contract used.

Table 6-8: NIGU Project suppliers and contract type used

Vendor	Service	Contract type	Procurement approach
Transfield Services Ltd	Civil works	Measure and value	Competitive tender
Transfield Services Ltd	Otahuhu-Pakuranga 2 design, build	Lump sum, fixed price	Competitive tender
United Group Ltd	Buildings & foundations	Lump sum, fixed price	Competitive tender
Electrix Ltd	Electrical installation	Lump sum, fixed price	Competitive tender

Duco Ltd	Steel works	Lump sum, fixed price	Competitive tender
Aecom New Zealand Ltd	Design services	Lump sum, fixed price (NEC)	Selective source
Watercare Services	Relocate sewer line	Purchase order	Competitive tender
Vector Ltd	Relocated 33kV cables	Vector conditions of contract	Selective source
CG Pauwells	Supply of Transformers	Lump sum, fixed price	Limited tender through panel contract
Various suppliers of 220 kV switchgear	Supply of 220 kV switchgear (hardware)	Lump sum fixed price	Current preferred supplier

Project Management

The Pakuranga substation works were managed in accordance with the PMP for the NIGU Project and standard Transpower project management processes.

The scope of the project was changed to incorporate the construction of a new control room, rather than an extension to the existing control room. This scope change significantly improved safety and will allow the full demolition of the old 110kV substation.

Demolition and removal of the existing 110kV yard has yet to be completed. This will not result in any cost to the project as it is to be allocated to operational expenditure.

United Group Ltd and Electrix each engaged a full-time safety officer for their respective phases of work to ensure a pro-active approach to safety on site.

The Project Manager and Environmental Manager were actively engaged with substation neighbours and participated in Transpower initiated public meetings on the project. These meetings were effective in ensuring the cooperation of the local community and affected property owners. For example, one outcome from these meetings was the planting of additional screening along the western boundary of the substation.

Financial performance of the substation works

Actual costs incurred to date are $30.7 million (excluding the old 110kV demolition). Final figures are not yet available as building is incomplete. However, we anticipate spending a further $0.5 million to complete the project. That is well within the GUP budget.

Table 6-9: Pakuranga Substation: Main Cost Areas and Savings against PAD

Cost saving area	Amount expected to be saved versus PAD
Primary Switchyard Plant	-$0.3m
Transformer T1	$0.9m
Transformer T2	$1.1m
220 kV Bus	-$0.9m
Civil, Earth Grid & Communications	-$2.1m
Lines – Connection changes and Decommissioning	$0.2m
Relocate Services PAK site	$0.2m
ARI Runback.	$0.4m, not required
Capitalised Interest	$0.9m
Contingency	$2.7m

Some aspects were not anticipated in the original scope of the project and these put pressure on the PAD budget. The most significant was around risk management and contingency planning during commissioning. An additional $250,000 (approximately) was spent maintaining the security of supply at Pakuranga to an N-1 standard during the three months of commissioning.

6.2.4 Otahuhu substation

Table 6-10: Otahuhu substation costs

Date	Description	Amount	Variance
October 2006	GUP estimate (OTA sub, OTA enabling and OTA-PAK upgrade, P90)	$11.5m	-
April 2008	OTA-PAK Upgrade PAD	$0.8m	
January 2009	OTA PAD incl contingency	$9.5m	
July 2013	Final Cost	$14.0m	$2.5m

Overview of works

The Otahuhu substation project was a combination of three sub-projects in the GUP which comprised:

- enabling works for- cabling sections of three 110kV circuits to Penrose and Roskill substations, in order to clear Otahuhu-Pakuranga A cross-overs;
- upgrading the Otahuhu-Pakuranga A transmission line to 220kV operation; and

- Otahuhu substation related work for commissioning the Otahuhu-Pakuranga circuits onto separate 220kV buses and decommissioning the 110kV Otahuhu-Pakuranga circuits.

This project required effective coordination with the Otahuhu Diversity Project (**ODP**) during all stages.[37]

Contract award process

The 110 kV works were costed and designed prior to the construction of the new AIS yard at Otahuhu (which was constructed as part of the ODP). The tendered cable route in the Otahuhu substation was therefore unbuildable and the route needed to be redesigned by the successful tenderer.

The original PAD estimate was $7.7 million, however a contingency of $1.8 million was withheld by the programme manager. With the necessary re-design and changed works, the resulting total cost was $14.0 million.

Only two suppliers decided to bid for the 110 kV work, given the risks associated with the construction components and margins because:

- the full scope of works could not be determined at the time of tendering
- the cable runs were very short and therefore standard margins on materials were very low compared with the risks in construction (for example, the high technical risk areas such as cable end sealing were a high component of the work)
- there were a large amount of temporary works required within the 110 kV yard

These issues would have squeezed the margin on construction and it is apparent that some suppliers considered they would ultimately be uncompetitive.

Project performance - enabling works (110 kV cable works)

As the 110 kV cable works at Otahuhu were designed prior to the design of the new AIS yard at Otahuhu as part of the ODP, there were a number of variations to the scope of the contract to address the changes to the design and nature of the work, which included:

- redesign of the cable route from in-situ concrete trough construction to direct buried construction to save costs;
- new tower and cable termination poles;
- retaining the conductor for the Otahuhu-Pakuranga 1 circuit rather than converting it to scrap;[38]
- switching from bored pile foundations to screw pile foundations;[39] and
- extra reinforcing to the foundations.

37 The Otahuhu Diverstiy Project (**ODP**) was implemented via a separate Grid Upgrade Plan to provide diversity at the Otahuhu substation. Planning for the ODP occurred after the planning for the NIGU Project, although the ODP construction works were undertaken concurrently with NIGU and ultimately commissioned before the completion of NIGU.

38 This required extra care (and therefore expense - $20,000) in the removal works.

39 This saved $150,000.

Given the redesign required due to the ODP, the works involved could not have been accurately forecast at the time the GUP estimate was compiled. (The planning for the ODP occurred after the planning and cost estimates for the NIGU grid upgrade plan.)

The amount budgeted in the GUP for the enabling works was $4.2million and the actual cost was not determined.[40].The expenditure on the OTA-PAK upgrade as part of this OTA substation Works, for which the GUP estimate is not included, was $2.9m

Project performance - substation works (220 kV cable works)

The 220 kV cable works were partially undertaken as a variation to the ODP with completion of the works being undertaken as a variation to the 110 kV cable works contract.

Changes to the design and installation work required due to the ODP, resulted in several additional changes to the 220kV cable scope of works. These included:

- an additional contract to employ the 220 kV cable supplier to terminate the cables;
- allowances for the refurbishment of the circuit breaker and associated bay equipment required to commission the 220 kV cables;
- re-design of the termination span;
- installation of two new pole structures and commissioning of the new Otahuhu-Pakuranga-Penrose circuit to ensure reliability of supply; and
- a change to the cross-arm configuration of Tower 2.

Both the 220 kV and 110 kV cable works were completed within the operational constraints imposed by the Rugby World Cup 2011 and the commissioning requirements for the Pakuranga substation project. Both projects were delivered without any quality issues.

We had estimated in the GUP that these works would cost $6.435million and the actual cost was not determined[40].

6.2.5 Whakamaru substation

Table 6-11: Whakamaru substation costs

Date	Description	Amount	Variance
October 2006	GUP estimate (P90)	$17.4m	-
Apr 08, Jun 09	Approved PAD's	$20.2m	-
September 2011	Adjusted PAD	$ 21.5m	
July 2013	Forecast End Cost	$17.9m	$0.5m

40 These figures however are difficult to support as the line between Otahuhu Substation works and Otahuhu Enabling works is subjective and therefore unclear and secondly costs were not allocated

Overview of works

The Whakamaru substation and extension works project enabled the connection of the Brownhill Whakamaru transmission line at Whakamaru, and comprised works for the new Whakamaru B substation extension and the existing Whakamaru switchyard.

The works were completed on time only marginally above the GUP estimate. The substation works comprised:

- detailed design of the stage 1 new switching station at Whakamaru North, associated 220 kV double circuit Whakamaru B - Whakamaru tie line and associated 220 kV double circuit terminal span from Whakamaru B to the first 400 kV transmission tower (no 429);
- detailed design of the stage 1 switchyard extension at Whakamaru and upgrading of Whakamaru local service supplies, to match Whakamaru B reliability standards;
- procurement, construction, and commissioning of the new works, in concert with livening of the new 400 kV capable Brownhill - Whakamaru transmission line; and
- procurement, construction, and commissioning of the new works in concert with commissioning of the Whakamaru B and the Whakamaru A-B tie line.

Contract award process

We followed Transpower's usual substation contracting model. This involved separate design, earthworks, civil, building and installation contracts and the procurement of electrical equipment by Transpower.

Design: Selectively sourced to Beca, based on their having done the conceptual design. Price compared with other similar works.

Civil Works:	Competitively tendered to seven pre-selected civil tenderers.
	Successful tenderer - Downer
Electrical:	Competitively tendered to Transpower pre-qualified tenderers.
	Successful tenderer - Transfield
Tie Line:	Selectively sourced to Electrix, as the only available resource

All changes to project time, scope and budget were individually reviewed and approved within standard Transpower processes. If the approved variation would result in an increase against the purchase order, an additional step to gain financial approval to increase the price was required.

Project Management

The Whakamaru substation works were managed in accordance with the PMP for NIGU and standard Transpower project management processes.

The communications plan for the construction phase of the Whakamaru project was effective and well executed. This is largely attributable to having communications staff as part of the project team.

Project performance - substation works

The final PAD estimate was $21.5 million. Actual costs of $17.9 million were incurred, as outlined below. Areas of cost variation to the final PAD budget are set out below.

Table 6-12 Whakamaru Substation: Main Cost Areas and Savings against PAD

Cost saving area	Amount expected to be saved versus PAD
Design	$0.6m
Project Management	$0.3m
Station Procurement	$1.6m
Station Construction - Civil	-$1.3m
Station Construction - Electrical	$0.2m
Tie Line Procurement	$0.1m
Tie Line Construction	-$0.3m
Property, Site Establishment, Battery Room.	-$0.1m
Capitalised Interest	$0.5m
Contingency	$1.3m, Not required

The main reason for the cost increases and decreases are:

- Complexity of the old Whakamaru A substation increased design costs. However detailed design costs of $1.33 million were captured incorrectly in the NIGU substations general cost category;
- Reduced site representation due to effective contractor;
- Pricing of substation equipment was much sharper than expected;
- Unexpected ground conditions including tomos in the substation platform;
- Tender prices for the electrical installation were very competitive and we managed to keep variations under control;
- Some second hand towers were used on the tie line;
- Tie line Construction – Ground conditions resulted in bigger foundations than anticipated;
- Generally the project was under budget therefore interest charges were less than expected;
- As savings were more than the cost overruns these could be funded from savings, therefore there was no need to use contingency.

7 Property costs

($187m expenditure against GUP P90 estimate of $126m)

7.1 Summary

Table 7-9: Property costs

Date	Description	Amount	Variance
October 2006	GUP estimate (P90)	$125.7m	-
July 2013	Forecast End Cost	$187.4m	$61.7m

The property component of the NIGU Project involved acquiring the property rights necessary to construct the new transmission line, lay the underground cable and enable the substation projects. It also included paying compensation for property-related effects, and other transaction costs associated with property.

Several factors contributed to significantly higher property costs than originally forecast and approved by the Electricity Commission, primarily:

- a failure to include costs associated with the movement or removal of buildings, trees and other hazards along the new transmission line route, compensation for the loss in business and value of land adjacent to the route and income tax gross-ups on easements
- higher than anticipated easement compensation payments to landowners along the new line route, due to:
  - the uncertainty of the methodology used to estimate easement and compensation costs in the GUP;[41]
  - a refinement of the compensation calculation methodology following discussions with valuers representing landowners;
  - some negotiated settlements with landowners, where valuations prepared by independent valuers were larger than anticipated;
  - substantial and unanticipated increases in property values in the central Waikato from the time the NIGU project was approved by the Electricity Commission to the time easements were acquired for the Project; and
- higher than anticipated Transpower staff and property owner administration and transaction costs, arising from delays in Electricity Commission approval, BoI approval and protracted negotiations with landowners.

We had robust property acquisition strategies and practices in place for the NIGU Project, in order to minimise costs. Specifically we:

41 We had limited experience in purchasing easements for an overhead transmission line of this scale.

- negotiated and sometimes bought freehold land in anticipation of the likely outcomes of the Electricity Commission and BoI processes;
- negotiated against pre-approved negotiation positions and limits of variance from valuations prepared for Transpower (and reviewed as circumstances required);
- where negotiations stalled, used the compulsory acquisition process to the extent possible within the NIGU Project timetable; and
- acted in such a way as to maintain goodwill as far as possible, ensuring generally positive attitudes and compromise from all parties at the negotiating table.

While the NIGU Project incurred higher than anticipated property costs, we consider that all expenditure on the property component of the NIGU Project was reasonable and efficiently incurred.

7.2 Property rights acquisition strategy for the NIGU Project

7.2.1 Key elements of the property acquisition strategy

We recognised early that obtaining the necessary property access rights and easements was a key risk factor for the NIGU Project.

Undertaking site inspections for planning purposes required the cooperation of landowners. Optimal construction of the new overhead transmission line required easements (or freehold properties) to be obtained either prior to commencement of construction activities or in a manner that enabled sequential construction.

Accordingly, we identified the key risks to securing the required property rights and proposed mitigation strategies to ensure that the NIGU Project objectives could be met.

This strategy was reviewed by both Pricewaterhouse Coopers[42] and Chapman Tripp.[43] Chapman Tripp concluded that our strategy provided an excellent mechanism to ensure uniformity and consistency in approach.[44] Pricewaterhouse Coopers observed that the easement acquisition and approval process documentation was clear and logical and that the compensation valuation process attempted to define a transparent and fair process for determining compensation for landowners.[45]

The core strategy throughout the NIGU Project was to obtain property rights “in a timely and cost efficient manner whilst fostering amicable relationships with landowners”.

42 Pricewaterhouse Coopers, Review of Process Involved with the Acquisition of Easements, 12 December 2006 – supporting document 8.3.5.

43 Memorandum from Chapman Tripp to Transpower, Review of Process for Acquisition of Easements and Land for Transmission Corridor, 6 December 2006 – supporting document 8.3.4.

44 Memorandum from Chapman Tripp to Transpower, Review of Process for Acquisition of Easements and Land for Transmission Corridor, 6 December 2006, para 5 – supporting document 8.3.4.

45 Pricewaterhouse Coopers, Review of Process Involved with the Acquisition of Easements, 12 December 2006, para 11 – supporting document 8.3.5.

The strategy was reviewed and updated from time to time, to identify any additional or emerging risks to securing the required property rights, and to propose mitigation strategies for those risks to ensure the project objectives could be met.[46]

7.2.2 Underlying considerations for property acquisition strategy

When preparing our property acquisition strategy we were mindful that:

- landowners were likely to consider that we would start with an offer lower than our best price;
- landowners would be concerned that other landowners may be getting a better deal, and that misinformation may well be spread by other landowners;
- landowners would "hold out" – thinking that those who "held out" may get a better offer; and
- Transpower needed to maintain a working relationship with landowners in order to maintain the completed transmission line.

7.2.3 Initial approach to securing property rights

Prior to obtaining Electricity Commission approval and when the NIGU Project plans were first developed, our approach was to acquire an easement in gross over affected properties. However, to mitigate delays in the approval process, and to develop momentum in terms of property acquisition we subsequently moved to acquire freehold titles to properties along the anticipated line route.

The objective was to purchase freehold properties, create easements over them suitable for the transmission line and then on-sell the land at a price that reflected the change in value as a result of the easement. The proceeds of these sales could then be used to acquire additional properties. The GUP property cost estimate included the cost of these easements, however freehold properties were purchased against Transpower's balance sheet, as they would not become a permanent asset and could not therefore be capitalised against the project. The expectation was in the event that the Electricity Commission, or Board of Inquiry declined Transpower's applications, the properties could be on-sold free of encumbrance. If we had acquired easements before the Electricity Commission and other statutory approvals were obtained, we would not have been able to recover the costs of those easements if the NIGU project had not gone ahead.

Following Electricity Commission approval in 2007, we confirmed our preference for acquiring easements instead of freehold titles. Freehold purchase became a back-up option when the purchase of an easement was not practicable or could not be achieved by negotiation.

7.2.4 Cost of freehold purchase

Freehold property purchases have been costly to Transpower because market prices deteriorated following our acquisitions. Many of the larger properties purchased outright were acquired at a time of high rural property prices.

46 See Transpower Internal Memorandum, NIGUP Transmission Line – Property Strategy to Achieve Project Objectives, 24 October 2008 – supporting document 8.3.1.

We acquired:

- prior to 2007, $141 million of freehold properties;
- in 2008 and 2009, $36 million of freehold properties; and
- from 2010, $37.6 million of freehold properties.

The terms of the 2008 administrative settlement [47] and the currently applicable input methodologies [48] provide that where Transpower purchases a property with the intention of registering an easement and then reselling that property, then any resulting gain or loss in the value is not passed on to customers. Accordingly, we have not attributed any losses or gains on the resale of freehold properties to the NIGU Project and do not seek to recover any such costs from our customers.

Both rural property prices and market liquidity were constrained in the period following easement registration, when we were seeking to exit properties we had purchased outright. Currently, the loss borne by our shareholder on resale of the freehold properties is approximately $52m.

7.2.5 Easement acquisition process

We used an internally approved and externally reviewed easement acquisition process.

PwC reviewed the easement acquisition process, observing that the process:

> “Has a number of strengths. The process documentation is clear regarding the key decision points and who has responsibility for making those decisions. It provides landowners with the opportunity to obtain their own valuation and to negotiate with Transpower. There are checks and balances on the decisions in the process and on the valuations completed.” [49]

Standard forms for an agreement to grant easement, easement, and agreement for sale and purchase were all developed and approved internally.

Our acquisition process had a general focus on consistency of approach and documentation, and good faith negotiation practices.

In almost all instances we negotiated a compensation amount that lay between the valuations provided by two independent valuations (one obtained by Transpower, the other by the landowner).

47 Commerce Act (Transpower Thresholds) Notice 2008, Schedule 1, clause 4(4) – supporting document 3.8.

48 Transpower Input Methodologies Determination [2012] NZCC 17, clause 2.2.7(1)(b) – supporting document 3.9.

49 Pricewaterhouse Coopers, Review of Process Involved with the Acquisition of Easements, 12 December 2006, para 15 – supporting document 8.3.6

7.2.6 Easement compensation assessment methodology

Background

As this was the first substantial use of easements for a transmission line in New Zealand, this was the first time that Transpower, and the valuers acting for landowners, had to value easements. There was little evidence in New Zealand about the effect of the proposed transmission line on “before and after” land values

We employed Crighton Anderson to develop a methodology for determining the easement compensation payable.

The Crighton Anderson model was established in the early 2000s, a Crighton Anderson valuation adviser travelled to Australia to test the methodology against those being used in Australia for lines of a similar size and voltage. Following that review the model was slightly amended.

The methodology considered fair compensation for the land taken, any injurious effects of the taking, and miscellaneous matters such as business loss and permanent disturbance. It was also consistent with the methodology ordinarily employed for Public Works Act acquisitions.

The compensation assessment methodology is explained in more detail in the supporting documentation.[50]

Corridors of effect

The compensation calculation included an assessment based on the “corridors of effect” of the transmission line. This approach recognises that in addition to the loss in value of the land occupied by the transmission line, there is also a loss of aesthetic value and other injurious affection to land adjoining the easement corridor. Corridors of effect reflect that the graduated drop in effect according to the distance from the line.

The methodology was presented to a valuers’ forum at the start of the NIGU Project. The forum was held to explain how Transpower’s valuers were going to approach the assessments and to obtain information from valuers who were anticipating acting for landowners, as to how they intended to approach the process. We hoped to establish some common ground between valuers to achieve as much consistency as possible. We believed it was in both Transpower’s and landowners’ interests that local advisers to landowners had as much information as possible about the NIGU Project and Transpower’s valuation approach.

While there were synergies between the various approaches, some valuers adopted different inputs within their models. This became clear once negotiations with landowners had started and we revised our inputs accordingly, to come into line with the increasing body of evidence provided by external valuers. This resulted in a cost increase compared to the initial property cost estimate.

The impact of this change on the modelled estimate is set out in more detail in Section 7.5.

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[50] Public Works Act 1981, Guide to Assessing Compensation for Compulsory Acquisition; Crighton Anderson (April 2004) – supporting document 8.3.8.

7.2.7 Contribution to landowners' legal costs

Consistent with the standard LINZ process for compulsory acquisition, we contributed to landowners' legal costs. In some instances, we dealt with large groups of landowners through a single independent solicitor. Because we were able to utilise pre-agreed forms of agreement, this simplified negotiations and resulted in a faster and less expensive process.

In other cases, perceptions that the easement documentation was unbalanced in favour of Transpower persisted, which prolonged negotiations and delayed the settlement of easements.

7.2.8 Compulsory acquisition

Section 186 of the Resource Management Act provides for the compulsory acquisition of land on behalf of a network utility operator.

We were reluctant to use compulsory acquisition because it is a protracted process that would have caused delays to the Project. It would also have undermined our strategic goal of treating all landowners in an equivalent manner and severely impacted long-term relationships.

Furthermore, several other complexities and risks were identified with the section 186 process:

- it did not guarantee that an easement would be secured;
- a section 186 application could only be compiled with the information available to Transpower and given that we were refused access to many properties, there was a risk that once we did have access, we might find that we could not physically construct the works with the land acquired;[51]
- landowners were able to challenge any acquisition in the environment court which could take considerable time to resolve;
- it required Transpower to attempt to negotiate in good faith first , and in some cases there was not enough time for an appropriate negotiation and a compulsory acquisition process without compromising the project delivery date;
- the negotiation process is run by LINZ, which meant that Transpower would lose control over the timing of an acquisition; and
- we were uncertain as to how far LINZ could progress a compulsory acquisition prior to Transpower having its designation confirmed.

However, to ensure that compulsory acquisition remained an option, we took steps to enable the process to be started quickly if required. A compulsory acquisition working group was established to identify and monitor those landowners whose land may need to be compulsorily acquired, and to be prepared to compile compulsory acquisition applications should the need arise. A robust sign-off process was established to ensure that compulsory acquisition was only undertaken as a last resort.

Despite our reluctance to use compulsory acquisition, at the start of the Project it was anticipated that as many as 100 easements may need to be acquired through the Section 186 process. Measures were taken to ensure that LINZ had the capacity to deal with any section 186

51 In such a case we would have to start the section 186 process again with a further delay to the project.

applications as a priority, including appointing a project manager at LINZ to deal with the potential workload.

In practice only a handful of properties were initiated in the process and none went the full course, being resolved through negotiation.

7.2.9 Interface with other NIGU work streams

The Transpower Property Projects Group was established as a part of the NIGU Project to manage the timely and efficient acquisition of property rights and to interact with the Alliance (which was formed to construct the overhead line, explained further in Section 8). There was a significant amount of information exchanged between the Transpower Property Group and the Alliance as to progress with securing property rights. This ensured that the Alliance could, to the extent reasonably practicable, programme construction works for the overhead transmission line efficiently based on the properties available to them.

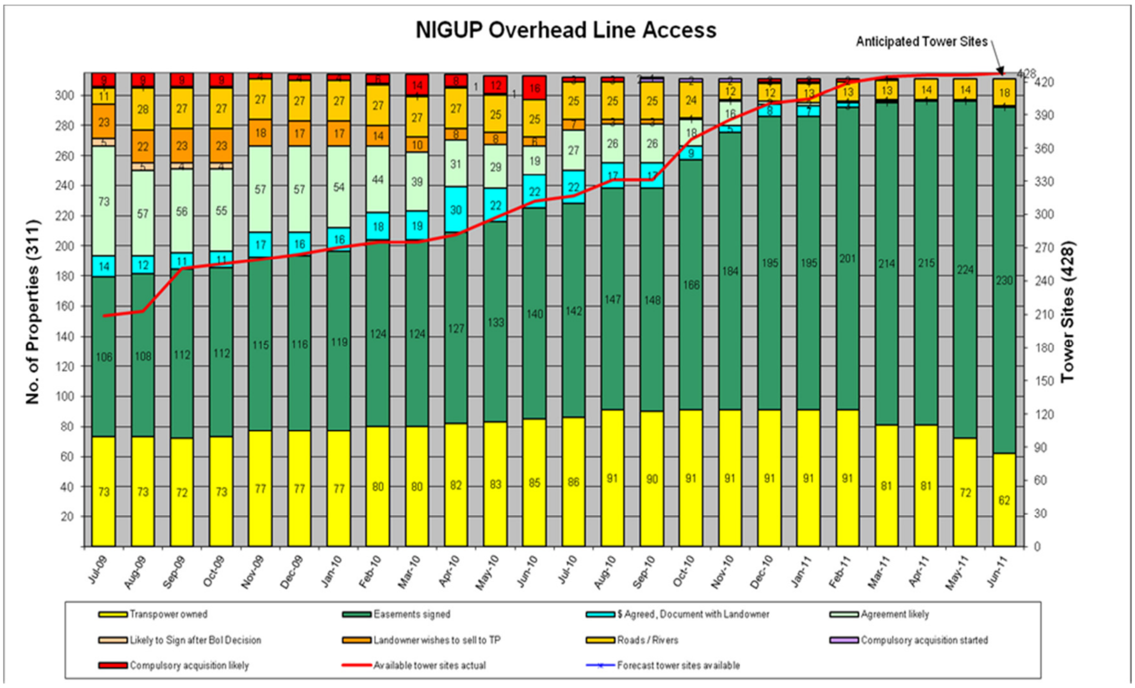
7.3 Engagement with landowners and impact of delays in obtaining regulatory approvals

The delays in obtaining regulatory approvals are discussed in Section 3.

Easement negotiations were not able to progress properly until after the Board of Inquiry released its final decision in September 2009. Many landowners would not discuss compensation issues or engage with us prior to this as they did not believe we would obtain the required approvals. The window to buy property rights narrowed significantly as a result.

Although there was less time to negotiate with landowners, landowners themselves were in no hurry and were able to leverage our reduced timeframes to drive acquisition costs upwards. The majority of the easements were negotiated between 2008 and 2010. The following graph shows that in July 2009 (just after the BoI released its draft decisions), property agreements for about 44% of the line were still outstanding. Overhead line construction commenced in January 2010 with nearly 40% of agreements remaining outstanding. By July 2011, we had obtained easements or other necessary property rights on all 318 properties crossed by the new transmission line ahead of commencement of stringing activity.

Figure 7-3: NIGU overhead line access



The delay in obtaining designations and resource consents and the earlier delays associated with the Electricity Commission approval process placed upwards pressure on the property compensation budget. Delayed access to property also had a significant adverse effect on construction of the new transmission line, as discussed in Section 8.

7.4 Key factors that contributed to higher than anticipated property costs

7.4.1 Substantial increases in property values

Summary

The combination of higher than anticipated easement values and higher than budgeted property inflation resulted in a substantial increase in compensation payable to landowners for easements required for the NIGU Project. This is a significant factor in the NIGU Project costs exceeding the MCA approved by the Electricity Commission.

Assumptions underlying initial estimate

The increase in property prices could not be anticipated at the time the GUP was being prepared.

During the preparation of the property cost estimate for the GUP, Transpower and the Electricity Commission had frequent discussions about contingencies in the property section of the estimate. Initially, the Electricity Commission was very clear that it would not allow a property cost estimate which allowed for property growth other than at the rate of CPI. To arrive at an estimate, the property growth rates across Waikato for the past 50 years were considered, which ultimately led the Electricity Commission to approve an estimate which catered for prices rising with the CPI plus 3%. This led to a property inflation estimate of 6% per annum.

Increases in property values

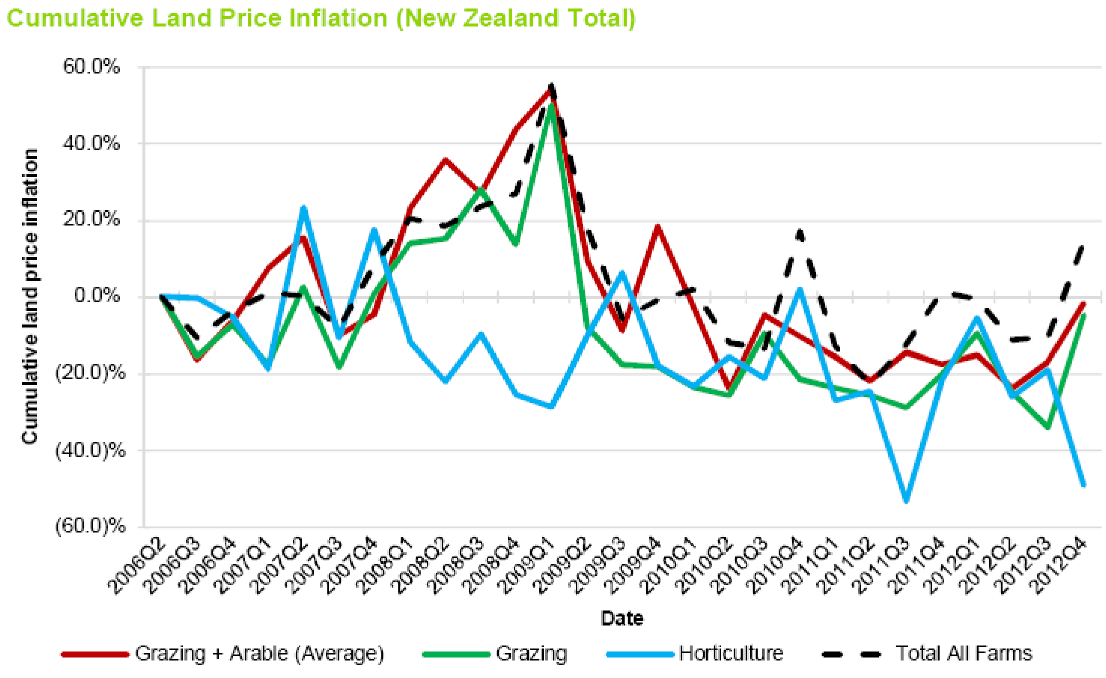
During the period between Electricity Commission approval in July 2007, and the release of the BoI decision in May 2009, the market prices for rural property increased substantially due to:

- the economy-wide property boom; and
- a rapid increase in dairy prices for during the period between 2006 and 2008, which drove an increase to dairy farm prices at a greater rate than the wider property market.

Between developing the original property cost estimates for the GUP and the peak of the property boom late in 2008, actual property inflation was approximately 16% per annum, which accumulated to a 40% increase over that time.[52] Some Waikato dairy farms increased in value from around $30,000-$35,000 per ha up to $60,000 per ha.

Transpower could not avoid paying additional easement compensation due to the substantial increases in property values.

Figure 7-2: Land price inflation 2006-2012



Source: REINZ and Deloitte analysis

The property market dipped dramatically late in 2008, after two years of rapid increase. Landowners took the view that delays in reaching agreement were Transpower's problem, and that we should settle at pre-dip valuations. Others viewed the dip as temporary and were prepared to wait for prices to recover. Further, some landowners felt that with declining property prices, a Transpower easement would have an even greater adverse effect on their property values, given

52 See Deloitte, NIGU Project Land Cost Analysis, 7 August 2013 – supporting document 8.3.3

that it was already becoming more difficult to sell. As a result, easement costs did not decrease in association with the 2008 downturn in the market.

Deloitte observed in its report:

> "…land prices increased sharply through the period to mid-2008 before falling sharply until mid-2010….A significant proportion of the [easement] purchases were completed after land values peaked in mid-2008. This, combined with the difficult negotiating environment and restricted route options for Transpower, is likely to have continued to drive the price Transpower was required to pay for land well after the land price index had started to fall." [53]

Notably, if land prices are indexed to the actual date of purchase then Deloitte observes that the total indexed easement cost is $89.4 million. However if land prices are indexed to the peak that the index reached, then the indexed cost increases to $141.8 million.[54]

Impact on negotiations with landowners

As part of the easement strategy, we resolved to have the final easement cost remain within a certain percentage of the initial independent valuation we obtained. This was ambitious, given the factors driving price ambiguity, including:

- landowners' ability to "hold out" and bargain;
- the incentives on landowners to delay negotiations in circumstances where property prices were increasing steadily;
- once approved, the route could not be changed providing landowners with a significant negotiating advantage;
- the regulatory and consenting process had attracted much adverse publicity, creating a hostile environment to negotiate purchases;
- the subjective nature of easement valuations; and
- the timeframe we had to complete the project works.

With compulsory acquisition neither preferred, nor a viable tool given the NIGU Project timetable and cost implications, our strategy evolved over time and the Transpower Board authorised negotiation at higher percentage bands compared to our own independent valuation. We still sought to acquire easements for the lowest cost possible and within the range between our independent valuation and a landowner's independent valuation.

Approximately 18% of easements were acquired at less than initial Grid Upgrade Plan estimates.

Impact of development potential

The rapid growth of Auckland and changes to district plans during the course of the NIGU project meant that, in some few instances, land was reassessed because of its new potential for development. For example:

53 Deloitte, NIGU Project Land Cost Analysis, 7 August 2013, p 6 – supporting document 8.8.3.

54 Deloitte, NIGU Project Land Cost Analysis, 7 August 2013, p 5 – supporting document 8.3.3.

- some properties initially assessed as dairy farms included lifestyle plots by the time the final compensation was agreed; [55]
- some plan changes near Auckland changed development potential and opened up additional land for development or focused development closer to the transmission line; [56]
- some land use changed from commercial forestry to dairy farming, with consequent increases in land value; and
- some change in land use was prompted by the introduction, after the GUP property cost estimate had been prepared, of an Emissions Trading Scheme (ETS) Commercial foresters were motivated to convert land to dairy farming before the ETS came into force. By the time the easements were purchased for the NIGU Project this ex-forestry land was worth around $20,000 instead of $5,000 per hectare.

The effect of these reassessments was to increase the easement value and compensation paid.

Easement width through forestry

The transmission line passes through commercial forestry land. Forestry owners became concerned about indemnity provisions in the standard agreements which they considered could make them liable if a tree fell onto the line. As a result, extra legal costs were incurred (discussed elsewhere) and Transpower agreed to increase the easement width to a minimum of 130 metres for the forestry properties. As a result of the increased corridors, extra easement compensation was paid, compared to the GUP property cost estimate.

Cost impact of increases in property values

Overall, the total easement and injurious affection compensation paid is expected to exceed the original estimate ($102 million) by $15 million. This amount is within the range established by Deloittes in its review of the impact of land price escalation, and well below the top end estimate of $141.8 million if land costs are indexed to the market peak. This indicates that the cost impact of higher than anticipated property values was effectively managed through our easement acquisition process. Higher costs were avoided through effective negotiation and other cost management strategies adopted as part of the easement acquisition process.

7.4.2 Removal of hazards and other non-easement compensation

At the time the property cost estimates were prepared for the GUP, we did not have a final line route for the new transmission line. We were working through an ACRE process, which determines line corridors.[57] These corridors varied from 500m to 3km wide, and a number of route alignments were identified in each, but there was little detail beyond that.

55 On one property, 28 lifestyle lots were created and plans were made for more development.

56 One property close to the Brownhill transition station, had a substantial change in value due to a district plan change that came into force after the original NIGU property cost estimates were prepared.

57 The ACRE (Area-Corridor-Route-Easement) design process is a multi-dimensional route selection process that reflects environmental, property and engineering constraints. It used to determine the most appropriate route for a transmission line, but prior to discussions with landowners. It provides a framework to identify effects, and avoid, remedy or mitigate those effects in accordance with the Resource Management Act.

When we submitted our GUP to the Electricity Commission, we were not certain which properties the new transmission line would cross and what hazard removal or other property-related works would be required at each site. We were only able to establish this once the designations were confirmed, the line route finalised and we had successfully acquired appropriate property rights. The reality was that there was no way to accurately estimate in advance the true costs of acquisition and the work needed to enable the new transmission lines to be constructed.[58] Around 60% of tower positions were moved after the GUP cost estimate had been prepared.

When the GUP estimate was prepared, we assumed that most buildings and other hazards could be avoided. We therefore made no allowance for the removal or allocation of these structures in the GUP cost estimates.

Following confirmation of the line route it became apparent that it would be necessary to remove or relocate some existing structures along the line route – even though these costs had not been budgeted for. Although buildings or structures could in theory have been avoided by altering the line route, it was more cost effective to move the buildings or structures than create additional angles in the route alignment. Angles in route alignment add significantly to tower engineering and construction costs for overhead lines, as towers to accommodate angles cost up to three times as much as standard towers and also add to visual impact.

It also became apparent, once detailed negotiations with landowners had begun, that in some instances it would be necessary to pay compensation for business loss and/or change of land use due to the proximity of the overhead line. In the most extreme example, we had to relocate a horse stud near Auckland as it was considered unviable to continue in business whilst we constructed the line.

The total cost of these unanticipated relocation and demolition works, plus compensation for loss of business, was $12 million.[59] Whilst these costs could not have been reasonably anticipated and estimated, given the lack of certainty as to route alignment at the time the GUP estimates were prepared, our responses to these additional challenges were appropriate and efficient.

Transpower developed the following strategy for resolving problems with buildings and other obstructions which kept costs to a minimum and maintained landowner relationships:

- once a hazard was identified, landowners would provide options for solving the problem.
- Transpower then assessed the viability of each option, including likely price;
- the parties then negotiated and agreed a solution and timeframe for the work;
- each party then obtained a more detailed estimate of the cost of the solution and the final cost of the work and any associated disturbance and business losses were negotiated and agreed; and
- the work was contracted by either Transpower or the landowner, as agreed and the costs settled.

58 This uncertainty was also signalled by Transpower in its submissions to the BoI, noting the need for tolerance for future movements of tower positions, as a number of sites were not able to be visited due to landowner lock-out.

59 Details of these additional costs are set out in the supporting information (see supporting document 8.3.1).

7.4.3 Increased cost due to subdivision potential

In some cases, landowners were actively considering plans to develop properties with subdivision potential. To the extent that owners were unable to unlock the full potential value because of Transpower's transmission line, extra compensation was payable.

At one property part of a subdivision had been started, and extra compensation was paid to mitigate the loss in potential and the cost of reversing the development.

These additional costs totalled $3 million and despite being unforeseen were carefully managed and efficiently expensed.

7.4.4 Forestry

A substantial part of the new overhead transmission line went through commercial forestry. This gave rise to a number of additional costs that were not anticipated at the time the property cost estimate was prepared for the GUP.

The costs were incurred:

- as over 300 hectares of commercial forest needed to be harvested at the southern end of the new transmission line (although the costs of removing the trees were offset against income from sale of the trees);
- because the transmission line restricts future logging and hauling operations and in some instances, we determined that paying for logging to occur earlier was more cost effective paying for trees to be felled on schedule and using a helicopter to remove them;
- to reflect the fact that trees could not be planted in the future; and
- to reflect the new ETS which resulted in Transpower assuming responsibility for $3 million of ETS liability on behalf of forestry owners.[60]

These costs amounted to $6 million in total.

7.4.5 Temporary disturbance

In accordance with our easement acquisition policy, we compensated landowners for temporary disturbance to farming operations during line construction, such as extra costs incurred while we were constructing towers and then stringing conductors.

This compensation was not provided for in the GUP property cost estimate because it related to construction activities on operational farms. However, it was not included in the transmission line construction estimate either. The lack of provision for temporary disturbance was identified once construction commenced, and as payments were required in addition to the cost of easements.

These payments are estimated to total approximately $3 million.

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60 We could not replant trees within the easement to offset the ETS cost and although we considered it, it was not economic to plant trees on other properties to provide some offset.

We developed a process, using data from independent advisors to assess temporary disturbance costs. These were then negotiated with landowners. Disagreements were rare, but when they occurred negotiations would be resolved by independent farm advisers.

Overall we consider these costs were unavoidable and efficiently incurred.

7.4.6 Income tax gross up

The addition of tax gross up clauses in some easement agreements resulted in approximately $6 million of unanticipated expense. No provision was made for income tax gross ups in the GUP property cost estimate.

7.4.7 Higher than anticipated staff, legal and transaction costs

The GUP property cost estimate included $8 million (in $2006) for all staff costs, professional fees, and legal costs including contributions to landowners' legal costs. Once inflation and IDC were added, this became approximately $10.5 million in commissioning year dollars. Actual costs are forecast to be $18 million. These higher than anticipated costs were due to unforeseen factors as discussed below.

The effect of protracted time for negotiation

The longer than expected time taken to negotiate individual property acquisition agreements resulted in:

- an increased number of valuations because rapidly changing land values rendered existing valuations quickly out of date;
- higher legal fees; and
- a greater labour component.

The original property cost estimate assumed two valuations per property. With the rapid rise in property prices between 2006 and 2008, valuations more than 2-3 months old were considered by landowners to be out of date and significantly more valuations were carried out than anticipated.

Other reasons for the labour cost increase

It became apparent that many landowners were not prepared to negotiate with us. Consequently, we initiated preparations for the compulsory acquisition process. As requested, a consultant was engaged at LINZ to cover the many potential properties that were identified as needing to be compulsorily acquired, based on our assessment of negotiations with relevant landowners. This was necessary to enable us to respond quickly in the event that negotiations with landowners were unsuccessful. The costs for the consultant and LINZ's preparedness were $0.5 million.

Of the $18 million spent in total on staff and transaction costs:

- $5 million is for Transpower's staff costs in the protracted negotiations with landowners;
- $7 million was spent on legal and valuation fees;
- $2 million was spent on property consultants;
- $0.5 million was spent on LINZ preparedness to conduct compulsory acquisitions; and
- $2.5 million was spent on miscellaneous items such as accounting and farm consultants.

Labour and transaction costs were managed in accordance with Transpower's standard processes (including competitive tendering of legal advisers), and we consider the expenditure was well managed and minimised to the extent possible in the circumstances.

7.4.8 Property costs for cable routes and substations

Cable routes

The property cost estimate for the Brownhill-Pakuranga and Brownhill-Otahuhu cable routes was produced on the basis of purchasing easements only.

The forecast end cost is $5 million more than the original estimate. Several factors contributed to this increase:

- When the cables were split into two separate routes, roads were unable to be used to the extent originally planned and additional easements were required.
- One route significantly affected the Regis subdivision. As a result of Transpower's designation, work had to be delayed on twenty sections within the subdivision which overlooked the Auckland skyline. During the delay, the property market crashed and compensation was paid for the lost value.
- Transpower contributed to the costs of constructing a road through the Regis subdivision to allow Transpower to lay the future Brownhill-Otahuhu cable in the road, and provide access to the cable at lower cost.
- For the Otahuhu cable route, we have purchased some properties without any intention to sell them after work has been done. These are properties where exclusive possession is required on a permanent basis. These properties enable access into the rear of the Otahuhu Substation. Most of the cable route will be under the road but once the route enters the urban subdivision that backs onto the substation it crosses some residential sites which have been acquired.

Substations

For the Whakamaru North and Brownhill substation sites, we have purchased properties without any intention to sell them after work has been done. An easement was not an option as Transpower requires permanent exclusive possession of the sites.

The $7 million cost for the Brownhill site is the same as allowed for in the original GUP. At the time the GUP was being prepared, we had identified the site and so the cost estimate was based on reliable information.

The $3 million costs for the Whakamaru land holdings are significantly in excess of the original GUP estimate. This was because we underestimated in the original GUP the cost of the Whakamaru North site.

7.5 Summary of property cost increase

We have explained reasons for the property cost increase, above.

The table below illustrates actual costs, measured against the original GUP estimate:

Table 7-2: Summary of NIGU property actual costs versus GUP estimate ($000)

		Original NIGU MCA	Actuals	Forecast	Forecast End Cost
Transmission line	Easements/Injurious	102,363	113,901	2,770	116,671
	Moving buildings	0	12,300	0	12,300
	Diff land use	0	3,000	0	3,000
	Temp disturbance	0	2,800	310	3,110
	Forestry	0	6,300	0	6,300
	Tax gross up	0	6,100	730	6,830
	Legal/valuations	10,500	16,900	1,250	18,150
		112,863	161,301	5,060	166,361
Cables	BHL-PAK		2,185	0	2,185
	BHL-OTA		6,348	1,640	7,988
		4,535	8,533	1,640	10,173
Substations	OTA		0	0	0
	PAK		0	0	0
	BHL		7,452	0	7,452
	WKM/WKN		3,447	0	3,447
		8,324	10,899	0	10,899
Total property cost		**125,722**	**180,734**	**6,700**	**187,434**

7.6 Conclusion –property costs for the NIGU Project

The higher than estimated property costs are due to a number of different factors over hundreds of property-related transactions. The main factors were:

- the adoption of incorrect assumptions at the time of the GUP estimate, specifically:
  - the extent of property inflation for land along the line route;[61] and
  - the parameters for calculation of easement compensation based on “corridors of effect”;
- the approval process took significantly longer than anticipated, which increased time pressure and raised costs; and
- the occurrence of the events that were not anticipated in the original estimate, in particular greater need for removal of buildings and other obstructions.

61 We also had to acquire the property immediately after a peak valuation period whereby property owners’ expectations as to the worth of their property was high and they were prepared to wait to achieve optimal compensation.

Transpower managed and controlled the property acquisition process in an efficient way by adopting and strictly adhering to an independently reviewed acquisition strategy and operational procedures. That strategy mitigated the impact of unforeseen circumstances.

This supports Transpower's view that all property costs for the NIGU Project are reasonable and have been efficiently incurred.

8 Overhead transmission line cost increase

($399m expenditure against GUP P90 estimate of $340m)

8.1 Summary

Table 8-10: Brownhill-Pakuranga transmission line costs

Date	Description	Amount	Variance
October 2006	GUP estimate (P90)	$340.1m	-
July 2013	Forecast End Cost	$398.8m	$58.7m

The overhead transmission line element of the Project comprised:

- the design, supply and construction of a 400 kV, 3 phase AC, 2700 MVA per circuit, double circuit steel lattice structure, overhead transmission line approximately 186 km long, from the Whakamaru North Substation in the central North Island to the Brownhill cable transition station, approximately 9 km south of Otahuhu; and
- the dismantling and removal of the existing 147km long Arapuni to Pakuranga 110 kV overhead transmission line. Part of the new 400 kV overhead transmission line follows along the same route as the existing Arapuni to Pakuranga 110 kV overhead transmission line. [62]

The overhead transmission line component of the NIGU Project was delivered using a project alliance agreement (PAA) between Transpower and Balfour Beatty New Zealand Limited and United Group Limited (BBUGL), a joint venture between Balfour Beatty of the UK and United Group of Australia. Below we explain the entry into, and operation of, "the Alliance".

The original P90 estimate for these works was $340 million.[63] In contrast, the initial, competitively-established Alliance price for these works was $235.3 million. This included a net price of $202.2 million, a risk allowance (that proved to be much too low) of $2.7 million and a Profit and overhead component of 15% of the net price (being $30.3 million). Including risk allowance and contingency the Transpower Board approved expenditure up to $276.5m for this contract. This did not however include other project costs such as insurance, IDC and other transmission line project management costs which were not part of the Alliance.

Total actual costs incurred or likely to be incurred are $398.8 million. This includes $326.8 million incurred by the Alliance (with the costs of dismantling the Arapuni-Pakuranga line being funded by credits for material sales) and Transpower project costs of $72.0 million.

62 Note that the GUP P90 estimate of $340.1m includes $5.9m for dismantling of the Arapuni-Pakuranga line. The actual cost of dismantling the line are not included in the forecast end cost however. These were previously expensed. For information, the cost of dismantling the Arapuni-Pakuranga line was $6.7m, but this offset by income from sale of the copper and steel of $8.9m.

63 Based on an allocation of the Electricity Commission approved P90 for the NIGU Project.

The higher than anticipated costs are due to:

- non-sequential construction activities caused by limited site access and delayed acquisition of easements, leading to fragmented foundation, tower erection and stringing works (accounting for an estimated $18 million of additional cost to the GUP estimate of $340 million;[64] and
- the effect of unforeseen scope variations, and the underestimation of certain foreseen costs, accounting for an estimated $40.9 million of additional cost.

8.2 Overview of estimate and actual costs

A high level analysis of individual cost items for the overhead transmission line works is set out in table 8-2 below. The reasons for the higher than anticipated costs of these items are set out in Sections 8.11 to 8.22.

64 Based on scope change requests presented by the Alliance.

Table 8-11: Summary of overhead transmission line costs

Northern Grid Alliance
BHL-WHN A 400kV OHTL
Cost to Complete Summary Report as at end August 2013:

Cost Element Description	Original TCE	Approved Scope Changes (TCE adjustment)	Current TCE	Anticipated Outturn Costs	Variance to Budget	Variance to Budget Commentary
INDIRECT COSTS	32.8	4.3	37.1	49.8	12.7	Longer project duration and larger workforce than anticipated resulting in higher costs for accommodation, visas, etc.
ENGINEERING AND TESTING	5.6	0.7	6.3	6.9	0.6	Tower and foundation design overruns
OFFSITE PROCUREMENT	66.9	5.3	72.2	69.7	-2.5	Conductor & OPGW savings compared to TCE
Tower steel price increase from TCE	26.2	6.8	33.0	32.7	-0.3	Price adjustment as provided for under the PAA
Conductor / earthwire price decrease from TCE	29.5	-1.6	27.9	27.9	0.0	Price adjustment as provided for under the PAA
SITE PREPARATION	31.9	9.2	41.1	51.5	10.4	Site conditions worse than expected resulting in more engineered accesses and remedial works from tomo formation
Tomo	0.0	6.6	6.6	5.9	-0.6	Tomo works undertaken on cost reimburseable agreement
31 Remeasure sites	0.0	2.7	2.7	2.7	0.0	31 sites re-measurable under PAA
CONSUMABLES	4.8	-0.3	4.4	10.5	6.1	More labour, plant and equipment required for the project than initially expected
FOUNDATIONS	22.9	1.9	24.8	48.3	23.5	Independent assessment (by WT Partnership) indicates foundation costs were underestimated in the TCE (of the $23.8m cost over-run, the re-measure has identified scope change entitlement to $6million and a further $2million for additional items to be considered by the ALT).
Raft foundations	0.0	1.5	1.5	2.0	0.5	
STRUCTURES	18.6	0.0	18.6	25.0	6.5	Tower productivity less than expected, productivity subsequently improved when specialist overseas based tower erectors arrived
STRINGING	13.8	4.3	18.1	36.1	18.0	Additional costs associated with Stringing Supergang to meet programme
EPR	0.0	0.5	0.5	0.5	0.0	EPR investigation and mitigation works
ARI-PAK DISMANTLING	4.3	0.9	5.2	6.7	1.5	Additional resources required than originally forecast
EXISTING 110kV LINE	0.1	0.0	0.1	2.9	2.8	Underforecast costs of scaffolding
ADDITIONAL ITEMS	0.0	8.5	8.5	8.5	0.0	BOI requirement for monopoloes, additional traffic management, QA issues
Monopoles	0.0	4.6	4.6	3.6	-1.0	Additional cost to erect monopoles
Terminations	0.0	3.8	3.8	3.2	-0.6	Terminations were outside the scope of the PAA
ALT DIRECTIVES / WARRANTY PROVISION	0.5	0.0	0.5	1.1	0.6	Warranty requirement under the PAA
SALE OF PROJECT ASSETS	0.0	0.0	0.0	-4.0	-4.0	Cost recovery from sale of vehicles and equipment
TOTAL ALLIANCE & TRANSPOWER COSTS	202.2	34.7	236.9	313.0	76.1	
Profit and Overhead	30.3	5.2	35.5	18.8		Current forecast of Profit & Overhead payable after painshare
Risk Contingency (No Margin Applicable)	2.7			0.0		
TP Direct Project Costs				19.5		
Procurement Costs (Hedging)				9.6		
Known risks provision				1.5		
Project Interest (IDC)				43.1		
Deduct ARI-PAK dismantling				-6.7		ARI-PAK costs separated from overhead line costs
TOTAL PROJECT COST	235.2	39.9	272.5	398.8		Current FEC (see FMIS reporting)

Key to Abbreviations in table 8-2

OPGW – Optical Pilot Ground Wire, an earthwire that includes fibre optics for telecommunications

TCE – Target Cost Estimate

PAA – Project Alliance Agreement

ALT – Alliance Leadership Team

ARI-PAK – Arapuni to Pakuranga overhead line

8.3 Background to the Alliance contract

The alliance contract model was chosen as:

- it was considered to be the best mechanism for managing the risks associated with the overhead transmission line works, namely:
    - our then lack of major transmission line building experience; [65]
    - the impacts of the design timeframe on the build process;
    - uncertainty as to land access (much of the access had not been secured when the contract was awarded and some properties could not be accessed for investigation until after construction had started);
    - uncertainties relating to the resource consenting process and regulatory approval processes;
    - the approach most likely to meet the 2013 need date.
- partnering with an international entity competent in recent high voltage line construction addressed Transpower's lack of recent experience
- the Alliance model enabled all parties to take collective ownership and management of the risks associated with the delivery of the project (rather than allocating these risks to various parties as would happen in a traditional contracting relationship)
- outcomes are collectively shared by the Alliance participants; [66] and
- it placed a strong incentive on BBUGL to produce accurate cost estimates and to understand and manage risks effectively.[67]

We sought and accepted advice from Evans and Peck, [68] who confirmed that a "modified competitive alliance" was most suited to the complexity of the overhead transmission line part of the NIGU Project in comparison to alternative options such as a traditional fixed price or cost reimbursable contract.[69]

8.4 Alliance tender process and evaluation

The following experts were engaged by Transpower in the tender and contracting process, to ensure that the Alliance was appropriately established:

- Evans and Peck advised on the establishment of a 'competitive alliance';
- Audit NZ acted as probity auditors;
- Sinclair Knight Mertz acted as Traspower's engineer; and
- Simpson Grierson prepared the contract and provided other legal advice.

65 The NIGU Project included the first major transmission line construction project undertaken by Transpower since the 1980s and the first 400kV line built in New Zealand.

66 BBUGL's profit and overhead margin on the project are reduced (and can go to zero) where extra expenditure is incurred which is not covered by scope variation adjustments to the target cost.

67 Variations under the PAA only apply in limited situations, and do not apply to risks which were foreseen

68 Evans & Peck, Project Implementation Strategy Review, August 2005 – supporting document 9.2.

69 Complexities included regulatory, designation and compulsory acquisition and property access risks.

In late 2005, a worldwide request for “registrations of interest” was issued to companies with transmission line capabilities, inviting them to submit a proposal for the design, supply and construction of the line. Four shortlisted companies were subsequently invited to submit a proposal for the works.

Following this process, the Transpower Board approved a recommendation to enter into an interim alliance arrangement with each of BBUGL and DownerEDI to prepare bids for the contract. We adopted this “competitive alliance” approach to further ensure that we received a robust bid from each of the two preferred tenderers, and to ensure they had a full understanding of the risks associated with the works. Transpower funded (within a cap of $1 million per proponent) the preparation of the detailed offers of the two preferred proponents and made one Transpower employee available to each proponent throughout the period to assist where required.[70]

As a result of this process, BBUGL was selected as the contracting party for the PAA on the basis of their transmission line construction and major project management experience, and their competitive tender price.

8.5 BBUGL

BBUGL is a joint venture business between Balfour Beatty of the UK and United Group of Australia. It was able to demonstrate experience in the design and construction of a 400kV overhead transmission line. Neither joint venture partner had prior experience executing a major project of this nature in New Zealand, but this was the case for all proponents.

8.6 Alliance governance

The NIGU Project Alliance was set up to act as a commercial entity separate to Transpower and BBUGL. It was known as the Northern Grid Alliance and referred to in this application as “the Alliance”. The Alliance is governed by an Alliance Leadership Team (ALT) comprising up to three senior representatives from each of BBUGL and Transpower.

The team provides leadership, governance, and oversight to the Alliance. The guiding principle is that ‘the participants have a peer relationship where each has an equal say in the decisions which are best for the project’. All decisions of the ALT must be unanimous.

Beneath the ALT, an Alliance Management Team (AMT) was established, comprising members from both Transpower and BBUGL.

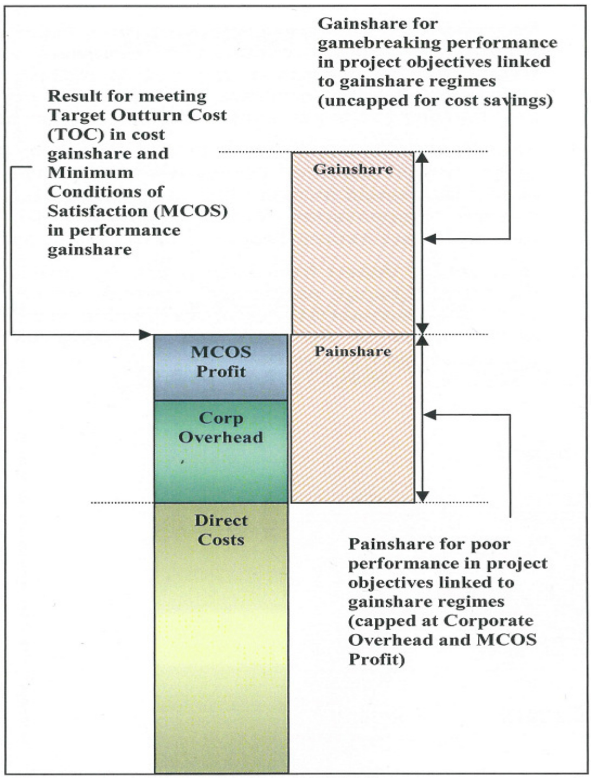
The AMT provides day-to–day management and leadership to the wider overhead transmission line project team. It consists of senior project personnel who work full time on the project. The AMT is headed by an Alliance Manager.

70 Detailed offers included preliminary tower design, estimation of quantities and assessment of access requirements.

8.7 Alliance contract pricing model and risk allocation

Both shortlisted proponents had to submit a target outturn cost to complete the works comprising an estimate of the actual cost, a risk allowance and the contractor's profit and overhead margin. The resultant target outturn cost was subject to a 50:50 contractor/Transpower pain/gain share depending upon how the actual total outturn cost compares to the target outturn cost. The contractor's pain share was capped at the value of the profit and overhead lump sum. Regardless of the application of the pain/gain share mechanism to the contractor's profit and overhead lump sum, Transpower remained liable for the Alliance's actual costs for the transmission line project. This is shown in Figure 8-1.

Figure 8-1: Pain and gain share allocation for Alliance contract



The Alliance therefore uses a pain/gain share arrangement based on a target cost estimate, which itself is based on the Alliance having responsibility for most construction risks, such as geotechnical conditions and access requirements.[71] However, Transpower specifically retained the risks around:

- access works for 31 tower sites which were unable to be inspected prior to signing the PAA, and were agreed to be "re-measureable";[72]

71 Practically, this means that Transpower still pays the actual costs incurred for the project. What is at risk for each cost item is whether the Alliance partner, BBUGL, receives profit and overhead on top of the cost incurred by Transpower, or shares in the "pain" by a reduction of the amount of profit and overhead.

72 Rates for relevant work were agreed and these applied to the actual quantities used to achieve access.

- changes in the actual type or depth of individual foundations;[73]
- mitigation required for earth potential rise;
- foreign exchange and raw material cost escalation;
- landowner disturbance payments; and
- obtaining, and responding to changes to scope of works as a result of, certain consent conditions (such as the switch to monopoles at Karapiro).

Although Transpower retained these specific risks, the pain/gain share mechanism saw the Alliance share most major uncertainties. In this way, all parties were incentivised to manage the known risks in a way that minimised costs, and in a manner likely to be more efficient than a conventional "fixed price" contract.

As observed by IQANZ, "[t]his [was] especially significant given the uncertainty risk in terms of the Board of Inquiry outcome, the timing for gaining property easements, the resource consent process (including any conditional approvals) as well as a myriad of other potential delays".[74]

Indeed, many of the known major risks which lead to the decision to use an Alliance model did occur and have justified the Alliance approach. For instance the project experienced:

- issues with availability and conditions of access to property;
- material supply issues;
- lack of suitably skilled labour within New Zealand; and
- consequential impacts on the timing and sequencing of the works.

8.8 Alliance scope and cost controls

Project management and cost controls processes were required as set out in the Scope of Works and Technical Criteria (**SWTC**),[75] as follows:

- Project Management Plan for the Northern Grid Alliance;
- Communications Management Plan;
- Document Management Plan;
- Quality Assurance Plan;
- Environmental Site Management Plan;
- Health and Safety Management Plan for all on the Project;
- Landholders and Stakeholders Communications Plan;
- Site Works, Access and Work Methods Management Plan; and
- Cost Management Plan for the Northern Grid Alliance

All of these project management and cost control processes were approved by the ALT and put in place before the commencement of construction activities. They were reviewed periodically during

73 Priced on a rate and measure, not a cost recovery basis.

74 IQANZ, Transpower – North Island Grid Upgrade Project: Follow up and Close-out Health Check Review, August 2013, p 3 – supporting document 11.3.

75 This is effectively the specification for the Alliance works.

the project, and updated where appropriate. They were also audited separately by UGL, BBUGL, Balfour Beatty and Transpower.[76]

A cost auditor (Rider Levett Bucknall) was appointed pursuant to the PAA, and was responsible for auditing and verifying reimbursable costs and costs incurred by Transpower and to ensure that BBUGL received their correct payment entitlements in accordance with the PAA.[77]

Project controls for the Alliance were implemented based on Balfour Beatty and UGL systems or as used previously by the BBUGL joint venture. For example, a detailed work breakdown structure was introduced which was derived from the cost coding system used by BBUGL for its major projects in Australia. Subcontracts were established between BBUGL, UGL or Transpower as appropriate (on behalf of the Alliance) and the subcontractor or supplier. A BBUGL standard form of contract was used for most large purchases and generally applied a schedule of rates model.[78] Transpower reviewed these terms and conditions before they were used for the Alliance works.

All requests for scope changes under the PAA required escalation to the ALT for consideration and resolution. The PAA places the decision making accountability with the ALT and so does not contain typical contractual dispute resolution processes. It does include a process whereby formal disagreements can be referred by participants to the ALT, which has to respond within 30 days. If the ALT is unable to resolve a disagreement, the participant may issue a “deadlock notice” which results in termination of the PAA after 20 business days.

8.9 Independent review by IQANZ

As noted in Section 3.9.2, we sought an independent quality assurance “health check” from Independent Quality Assurance New Zealand (IQANZ), on three occasions.

The purpose of these reviews was to determine whether the overall project management environment in place for the Project (governance, project management approach, processes, standards and controls) were appropriate, robust and in accordance with Transpower’s policies and procedures.

The 2009 IQANZ review of the NIGU Project work programme (undertaken before overhead line construction works began) concluded that:

- the programme established a strong governance framework and developed a novel approach to help minimise the uncertainty/timing risk with an existing joint venture company (BBUGL) in a pain/gain share relationship;[79] and
- the Alliance governance and management structure have been established with an appropriate supporting project management environment.[80]

76 Balfour Beatty and UGL also undertook frequent financial audits throughout the Project.

77 Project Alliance Agreement, clause 12.2 – supporting document 9.6.1.

78 For example, foundations, access, tomo remediation, crane hire and helicopter work.

79 IQANZ, Transpower – North Island Grid Upgrade Project – Independent Quality Assurance Review Report - Health Check Review, September 2009, p 3 – supporting document 11.1.

That said, subsequent IQANZ reviews did identify areas where improvements were required. In its final close out review in 2013, IQANZ noted that there were strong controls around expenditure and cost reimbursement to the Alliance, but weak processes around cost forecasting and provisioning for unknowns, until further expertise was injected into the project in 2011.[81]

Prior to the injection of further expertise, we had let the Alliance do its own forecasting, on the basis that the Alliance had the necessary expertise, experience and incentives. On closer inspection, it became apparent that they were not reforecasting every month on the basis of earned value or including sufficient provision for identified risks.

8.10 The impact of delays in obtaining regulatory approvals and access to properties

As a general comment, the delays to the start of the NIGU Project due to the factors outlined in Sections 3.3 to 3.5 had a wide ranging impact on the overhead transmission line works.

The Alliance contract was awarded on 22nd September 2008 in anticipation of a BoI decision originally expected in March 2009. To manage cost in other areas, other contracts with longer lead times were delayed until after the BoI decision. In particular, formal contract award of many of the major supply contracts for tower steel, conductor and fittings were delayed until after the draft BoI decision was released, in order to minimise incurring cost until there was greater certainty over necessary regulatory approvals.

The ALT approved the base-line programme for Alliance works in May 2009. The baseline programme was developed on the basis of a number of assumptions that linked back to the total cost estimate. This included production rates for access, foundations, tower erection and stringing. This programme was based on site works commencement in November 2009 and an overall NIGU Project completion date of 31 May 2012, later than the previously planned November 2011 completion date.

The commencement date and completion date were altered to reflect prolonged BoI process, with the Alliance undertaking a baseline planning programme to ensure works could commence as promptly as possible after designations and resource consents were confirmed.

However, the BoI approval had not been received at the time of baseline programme approval, and was ultimately not confirmed until October 2009. The requirement to obtain Outline Plan and Construction Plan approval from each relevant local council delayed commencement of works by a further 3 months.

Physical works on site did not start until January 2010, placing considerable pressure on the NIGU Project timetable.

80 IQANZ, Transpower – North Island Grid Upgrade Project – Independent Quality Assurance Review Report - Health Check Review, September 2009, p 4 – supporting document 11.1.

81 IQANZ, Transpower – North Island Grid Upgrade Project: Follow up and Close-out Health Check Review, August 2013, p 4 – supporting document 11.3.

8.11 Overview of financial performance and key cost increase factors

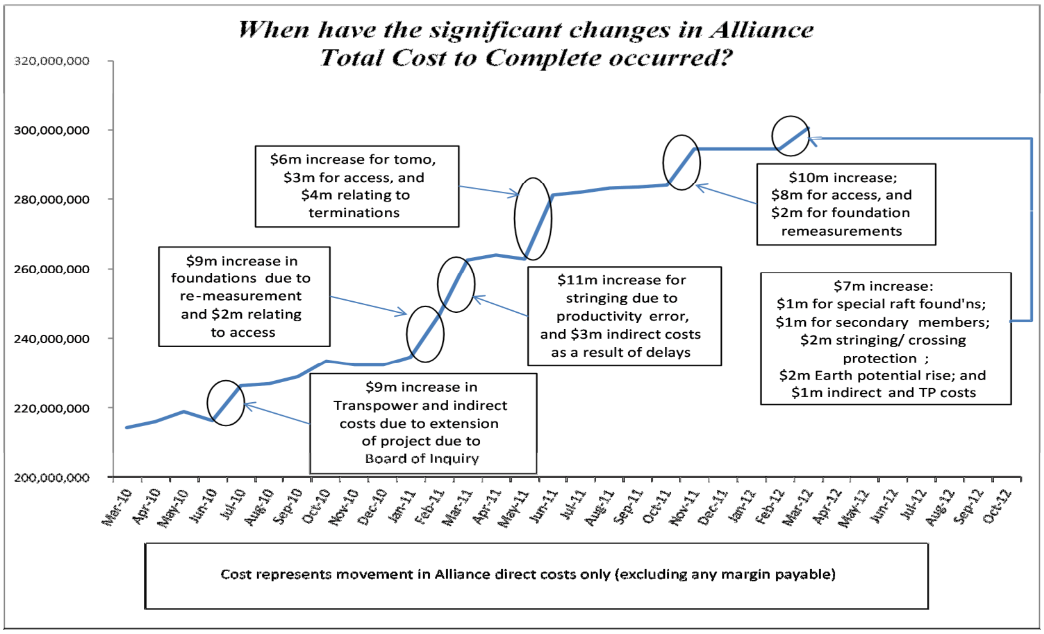
Throughout the project, the Transpower Board was provided with regular updates as to the how the overhead lines project was tracking.

It became apparent in early 2011 that costs for the overhead lines works were tracking above forecasts. The Transpower Board was advised in February 2011 that the costs for the NIGU Project as a whole (including the projected cost increase relative to initial forecast for property) were likely to exceed the $824 million MCA. At this time, higher than anticipated property costs were identified as the significant contributor to the NIGU Project exceeding its MCA.

Once cost increases became apparent, Board updates included reports on the management of costs associated with the events that were driving up costs on the overhead lines works.

A summary of the major changes to the cost to complete the Alliance works on the overhead transmission line are shown in the following chart.

Figure 8-2: Summary of changes to Alliance cost to deliver Brownhill-Whakamaru line



Some of this additional expenditure was anticipated in the PAA, and is the result of re-measureable items such as foundations, access to 31 named sites, undergrounding of low voltage under-crossings, changes in foreign exchange rates and commodity price fluctuations.

Other expenditure related to risks identified in the risk register developed prior to contract award such as the lack of geotechnical investigation and fragmented property access and these have contributed to a substantial portion of the cost increase. The cost consequences of these risks were under-estimated in the BBUGL tender, and the total risk allowance of $2.7 million included in the target outturn cost has proved grossly inadequate. However BBUGL shares in the outcome to the extent that it reduces their payment for profit and overhead, thereby incentivising all parties to minimise any costs in excess of the forecast target outturn cost. Transpower and BBUGL have agreed that the profit and overhead payment to BBUGL shall be $18.8 million, a substantial reduction from the original agreed value. BBUGL will therefore have made a significant contribution to the cost overrun.

Other reasons why actual costs have exceeded estimates include:

- an incorrect assumption in the GUP estimate and BBUGL tender that access to approximately 30% of tower sites would be possible without the need to engineer access tracks (ultimately, the Alliance installed engineered access tracks to nearly all tower sites);
- the suite of foundation designs assumed at time of tender based on the available geotechnical data proved inadequate and typically, larger and deeper (although of fundamentally similar design) foundations were required; and
- a BBUGL tender error around stringing productivity rates and cost meant actual stringing costs were more than estimated by BBUGL. [82]

8.11.1 Additional costs due to fragmentation of works

Fragmented access to tower sites adversely impacted cost. The GUP estimate assumed that the overhead transmission line construction work would be undertaken in a linear sequential manner. Also, as it was not possible to access the majority of sites at the planning stage, foundation design on many sites took place only shortly before construction which further limited the sites available for construction and reduced any flexibility in the schedule. Non-sequential work meant lower productivity as more time was spent traveling and there was less ability to utilise project resources in the most productive manner. To minimise delays, the Alliance adopted a strategy of expediting progress on individual properties, rather than necessarily waiting for sequential access along the line. Given the impact of a sequential approach on the overall schedule, the adopted approach was the most efficient.

Fragmented access was a risk identified at tender stage. The Alliance identified an additional $18 million of cost attributable to non-sequential construction activities, caused by limited site access and delayed acquisition of easements, leading to fragmented foundation, tower erection and stringing works. While this $18 million represents additional cost to the Alliance, the full cost is shared by BBUGL through the pain share mechanism.

These costs could have been mitigated, had the necessary property rights been obtained earlier or if the project timetable had allowed more time to obtain property rights to enable optimal construction sequencing.

Delays caused by the prolonged regulatory processes were beyond Transpower's control, but it is acknowledged that had Transpower started planning before 2003, some of this additional cost may have been avoided.

82 At its peak, stringing works employed approximately 120 people as opposed to the originally estimated gang size of approximately 60 people.

Overall:

- the end cost of $399 million for the overhead lines works was $59 million over the GUP budget; and
- the three key construction work-streams of foundations, access and stringing together accounted for the major areas of cost increase.

Set out below in Sections 8.12 to 8.21 is an explanation of the performance of each of the work streams that comprised the overhead transmission line component of the NIGU Project.

8.12 Site preparation and access

Table 8-2: Site preparation and access costs

Cost Element Description	Original TCE	Approved & re-measurable Scope Changes TCE Change	Budget	Anticipated Actual Direct Costs	Variance to Budget
SITE PREPARATION AND ACCESS	31.9	9.2	41.1	51.5	10.4
Tomo	0.0	6.6	6.6	5.9	-0.6
31 Remeasure sites	0.0	2.7	2.7	2.7	0.0

8.12.1 Access

A large number of sites were not able to be surveyed before cost estimates were prepared because of limited access and lack of certainty as to the line route. Initial cost estimates for site preparation and access did not adequately provide for poor site conditions.

As it was not possible to access many sites at the planning stage, foundation investigation and design took place during the construction phase, limiting the sites available for construction at any particular point in time.

In addition:

- designation and resource consent conditions required Transpower to construct access tracks and prepare sites in a way that preserved existing topography (rather than establishing "flat" sites by heavy bulldozing) which increased tower design and construction costs;[83]
- the quantity of tracking installed was twice the quantity initially anticipated (with the length, width and depth of the running course all increased) and site preparation and access road costs were higher than forecast;
- the Alliance determined that the most efficient approach to deal with the larger foundations and still meet the timetable was to increase site preparation and accessto

83 Tower sites also had to be reinstated to pre-construction topography.

enable more winter working and bigger equipment. Fully engineered crane pads ensured safety.

The Alliance mitigated the effect of the higher than anticipated construction track requirements by obtaining rates for access installation that were significantly less than the rates assumed by BBUGL at the time of tender. However the additional access works scope overwhelmed these savings.

8.12.2 Tomo formation

An additional unforeseen foundation issue arose due to the light, un-compacted volcanic ash soils at the southern end of the new transmission line, which are prone to the formation of natural voids called tomos. In a section of the line near Whakamaru (at the southern end of the line between towers 429 and 406), tomos formed around some of the foundations. These voids were large and had the potential to affect tower stability.

The tomos were concentrated in areas that Transpower was unable to access early in the project planning phase because landowners had refused to allow access for site inspections. Costs associated with these tomos were therefore not anticipated in the foundation budget approved by the Electricity Commission or the Alliance’s target outturn cost.

To address the problem and prevent future tomo formation, a methodology was developed involving ground stabilisation by grout injection. This work was staged and each plan was reviewed and signed off by Transpower for efficiency and constructability. The tomo remediation works were subject to a competitive tender to establish unit rates for the works and these rates were approved by the ALT. The works were undertaken on a cost reimbursable basis, as they were unable to be fully scoped prior to commencement.

We remediated a total of 30 tower sites at a cost of $5.9 million. When the tomo issue was first raised, the initial estimates for remediation were significantly higher.

The Alliance applied a best for project approach, Transpower checked the efficiency and applicability of tomo remediation costs and the cost auditor ensured that the additional costs were valid.

8.13 Foundations

Table 8-3: Foundation costs

Cost Element Description	Original TCE	Approved & re-measurable Scope Changes TCE Change	Budget	Anticipated Actual Direct Costs	Variance to Budget
FOUNDATIONS	22.9	1.9	24.8	48.3	23.5
Raft Foundations	0.0	1.5	1.5	2.0	0.5

Geotechnical conditions along the final overhead transmission line route varied from those anticipated by BBUGL and Transpower based on the limited geotechnical data that Transpower was able to obtain during the planning phase.

While some variability of ground conditions for foundation works was foreseeable, the extent of the variability was not. Access to properties to assess geotechnical conditions during the planning phase of the NIGU Project was generally refused by landowners, who resisted access until after completion of the BoI process and/or line route determination. In some cases geotechnical investigations were not completed until after easement agreements had been signed.

The cost estimates originally approved by the Electricity Commission were prepared on the basis of 27 geotechnical site investigations along the line route, substantially fewer than was optimal.

Foundation types (inclined piles) have remained roughly consistent with the original plans, but there has been a significant increase in foundation depths and average diameter due to the geotechnical conditions encountered. For example, the average planned foundation depth was 8 metres, versus the average depth installed of 14 metres. Total concrete volumes increased from 7936m3 to 20529m3. In a number of tower foundations each of the four legs have different pile depths, reflecting the variability of the soils. This variability increased foundation costs above estimates (plus risk allowance) originally approved by the Electricity Commission.

A schedule of rates based on foundation type was included in the PAA, with pile rates set at the time of tender. The rates used to remeasure the foundation scope changes remained largely unchanged during the NIGU Project, but the need to use larger and more board piles drove up costs.

The Alliance mitigated the slower than expected foundation completion rate by working over the winter of 2010 (which was not originally proposed in the 2009 baseline construction programme) and by increasing the amount and size of drilling and piling rigs. As mentioned in section 8.13 this also reflected into the access costs.

8.14 Offsite Procurement of Major Materials

Table 8-4: Procurement costs

Cost Element Description	Original TCE	Approved & re-measurable Scope Changes TCE Change	Budget	Anticipated Actual Direct Costs	Variance to Budget
OFFSITE PROCUREMENT (Comprises imported tower steel, conductor cable, earthwire, insulators, fittings, hardware, etc)	66.9	5.3	72.2	69.7	-2.5
Tower steel price increase from TCE	26.2	6.8	33.0	32.7	-0.3
Conductor/earthwire price decrease from TCE	29.5	-1.6	27.9	27.9	0.0

After contract award, the Alliance sought tenders for the supply of tower steel, conductor, earth-wire, insulators and hardware, to obtain greater certainty of costs and more favourable rates. The Alliance was successful in obtaining cost savings measured against the initial Alliance estimate.

That said, the tower steel price increased from the Electricity Commission approved budget. Steel was imported from overseas sources as domestically sourced steel was significantly more expensive. In contrast, the cost of the conductor/earthwire was lower than estimated in the Electricity Commission approved budget.

Foreign exchange was identified as a major risk early in the NIGU Project as most materials were sourced from overseas. Hedging was used to give cost certainty in accordance with Transpower's accounting rules. However, timing of deliveries had a major cost impact as the majority of hedges were adjusted several times to take account of late delivery due to a combination of Project requirements and supplier inability to meet agreed delivery schedules.

A further complicating factor was the need for the towers to be individually designed and constructed to meet designation and resource consent requirements relating to benching. This meant each tower was ordered with leg lengths to suit a specific site. A cheaper option would have been to develop a "standard" tower or towers requiring larger earthworks benching and/or various leg extensions, but this would not have satisfied environmental requirements to return the topography to within one metre of the original level or met the visual constraints of the consent requirements.

8.15 Tower erection (Structures)

Table 8-5: Tower erection costs

Cost Element Description	Original TCE	Approved & re-measurable Scope Changes TCE Change	Budget	Anticipated Actual Direct Costs	Variance to Budget
STRUCTURES	18.6	0.0	18.6	25.0	6.1

Slower than anticipated tower erection contributed to costs exceeding the GUP estimate and Alliance budget for tower erection works.

The predominant reasons for the slower than anticipated rates of tower erection were:

- low productivity rates, due to an initial inability to use a highly-skilled overseas tower installers until New Zealand labour had been fully investigated;
- winter working was more extensive than anticipated;
- availability of tower steel; and
- the out-of-sequence access to tower sites.

Overall, these factors led to additional expenditure of $6.1 million more than the tower budget..

BBUGL's tender cost estimate for tower erection works was based on using overseas-based tower installers with particular expertise. However, with the change in macroeconomic environment due to the global financial crisis and the restrictions placed on overseas work visas, local New Zealand labour was initially used for tower erection works.

Ultimately it was recognised that there was inadequate local resource available and approval was obtained from the Department of Immigration to engage overseas resources and subcontractors. Resource levels were increased from three tower erection crews (in November 2010) to 10 crews in the period between February and May 2011. The increase in labour costs associated with bringing in additional overseas labour to compensate for poor productivity by local staff meant that installation costs exceeded the allocated budget.

While there were productivity issues at the beginning of the NIGU Project, by identifying the issues (through commissioning independent reviews of the tower erection works) and remedying them (by bringing in overseas specialists including "lean construction" experts), productivity was significantly improved.

8.16 Stringing

Table 8-6: Conductor stringing costs

Cost Element Description	Original TCE	Approved & re-measurable Scope Changes TCE Change	Budget	Anticipated Actual Direct Costs	Variance to Budget
STRINGING	13.8	4.3	18.1	36.1	18.0
Earth Potential Rise (EPR)	0.0	0.5	0.5	0.5	0.0

BBUGL made a significant estimating error for the stringing component that went undetected in the bidding phase. While this increased the cost to the project (when measured against the ultimate Alliance budget), this error benefitted the project overall in that BBUGL shared some of the additional cost in accordance with the pain share mechanism, thereby reducing costs to the NIGU Project that might have otherwise been incurred.

The stringing works also suffered increased costs due to the following:

- Non-sequential stringing caused by the sporadic availability of completed towers resulted in additional costs. To address the sporadic availability of towers, the Alliance adopted a "super-gang" approach to resourcing, doubling the number of workers on a typical stringing gang. This option was considered cheaper than allowing further delay to the stringing timetable, which would have resulted in additional IDC costs in excess of the cost of the "super-gang". The cost impact of non-sequential stringing was included in the $18 million scope change request submitted by the Alliance in relation to extension of time for fragmentation of the works.
- Stringing began in October 2011 when the equinoxial winds were blowing, making sagging in accordance with the specification difficult. In addition, as the conductor bundle was triplex and non-symmetric, twisting in the wind was a further complicating factor. Systems and processes had to be developed to progress this part of the stringing. Sagging of the first two runs took some five weeks. This delayed further pulling due to

the requirement to have conductor hanging in the blocks no more than one week. Some progress was made by lifting the conductor and protecting it in the block, but this added to the cost and time for stringing. Eventually progress was improved and an average sagging rate of a run every 10-11 workdays was achieved by a combination of better weather, better topographical protection from the wind and some practical relaxation to the sagging specification.

- The budget for the stringing works did not properly provide for hurdles, nets and crossings to allow farming and other commercial operations on the relevant properties to continue while the stringing activities were being conducted in parallel. This was a requirement of the easement agreements negotiated with landowners.
- Some minor additional costs were incurred due to corrosion of the conductor stored at the port.
- A new standard on Earth Potential Rise (EPR) was introduced and the investigation and mitigation works to ensure compliance with that policy were not included in the initial scope of works for the new transmission line.

The Alliance engaged lean construction specialists KM&T, to advise on construction productivity and risk management associated with stringing works. KM&T was again chosen for its track record in delivering improvements in construction works and because it had a good understanding of the project constraints and the sequencing of interrelated activities required for the development of stringing production monitoring systems.

8.17 Karapiro monopoles and BHL monopoles

Table 8-7: Monopole costs

Cost Element Description	Original TCE	Approved & re-measurable Scope Changes TCE Change	Budget	Anticipated Actual Direct Costs	Variance to Budget
ADDITIONAL ITEMS	0.0	8.5	8.5	8.5	0.0
Monopoles (Karapiro)	0.0	4.6	4.6	3.6	-1.0
Monopole structures (Brownhill)	0.0	3.8	3.8	3.2	-0.6

The designation in the Waipa District and the Brownhill substation designation required the use of some steel monopole structures (rather than lattice towers) to address local concerns. The Lake Karapiro area is designated as a “Special Landscape Character Area” in the Waipa District Plan.

To address concerns about visual impact, seven monopole structures (three on the north bank and four on the south bank) were erected in the Waipa District instead of conventional steel lattice towers used elsewhere along the new transmission line.

8.18 Delays slowing removal of the Arapuni–Pakuranga line

Table 8-8: Arapuni-Pakuranga dismantling costs

Cost Element Description	Original TCE	Approved & re-measurable Scope Changes TCE Change	Budget	Anticipated Actual Direct Costs	Variance to Budget
Arapuni–Pakuranga DISMANTLING	4.3	0.9	5.2	6.7	1.5

The baseline programme for the removal of the Arapuni–Pakuranga 110kV line was developed around a five-month removal duration but the removal ultimately took twice this long.

This delay was due to a number of factors including:

- the removal procedure assumed in the Alliance tender was deemed unsafe and a change to the removal procedure was required;
- the removal of particular sections of the line to maximise the benefit for the new build, given property availability (parts of the new line and the existing Arapuni-Pakuranga line used a similar alignment); and
- that we assumed that 15 towers would need to be bundled and the steel provided to landowners but we ultimately did this for 185 towers.

Despite these factors, the costs for this aspect of the project were managed so as to ensure that costs incurred were reasonable and efficient. For example, Australian dismantling crews were used initially but we subsequently deployed less expensive New Zealand-trained crews re-patriated from Ireland.

Property access delays also slowed the removal of the Arapuni–Pakuranga line, which shares common sites and route with the new transmission line for much of its length.

Dismantling was initially deferred from November 2009 to July 2010. In July 2010, we still had insufficient property rights to remove the line safely and efficiently, so dismantling was further delayed until September 2010. Partial dismantling increases the risk of theft of copper which causes the line to drop and the consequences were significant given the numerous road and local power line crossings. There were no legal powers available under the Electricity Act to compel access to property to remove the line.

This delay caused a minor cost increase, but more significantly it increased the overall resource requirement as the existing Arapuni–Pakuranga line now needed to be dismantled in parallel with construction of the new line.

Overall, the dismantling and removal of the Arapuni–Pakuranga line was cost positive. Income from the sale of the old copper lines and tower steel was approximately $2.1 million greater than the dismantling cost. Although reported here for completeness, the cost and income from Arapuni-Pakuranga dismantling are not included as a part of the NIGU Project, as they have previously been expensed.

8.19 Crossing of Existing 110 kV Lines

Table 8-9: Line crossing costs

Cost Element Description	Original TCE	Approved & re-measurable Scope Changes TCE Change	Budget	Anticipated Actual Direct Costs	Variance to Budget
EXISTING 110 kV LINE	0.1	0.0	0.1	2.9	2.8

These works comprised the erection of scaffolding, nets and by-pass lines in the locations where the new overhead transmission line was being constructed over the following three existing lines:

- the 110kV Hamilton–Waihou A line that supplies power to the Coromandel region;
- the 110kV Arapuni–Edgecumbe A and B lines; and
- the 110kV Hamilton–Karapiro A line.

These lines could only safely remain in service while the works on the new overhead transmission line were undertaken by erecting scaffolding, nets and by-pass lines.

Although these works were anticipated, the full extent of the required works was substantially underestimated due to limited early site investigations and planning. Consequentially, costs were underestimated by a total of $2.8 million. Once the significantly increased scope of work was identified there was a strong focus on designing the most efficient solutions, all works were competitively tendered and we consider the works to have been efficiently executed.

8.20 Engineering and testing

Table 8-10: Engineering and testing costs

Cost Element Description	Original TCE	Approved & re-measurable Scope Changes TCE Change	Budget	Anticipated Actual Direct Costs	Variance to Budget
ENGINEERING AND TESTING	5.6	0.7	6.3	6.9	0.6

There was a $1.1 million increase in the cost of designing the towers and foundations due to:

- the restriction in the designation related to maintaining the original ground profiles. This drove the need for each tower to be specified for each site including different leg lengths for each leg. to be specified a bespoke engineering design process; and
- variable ground conditions that meant every tower leg had its own foundation design, with sometimes four different designs at the same tower site.

In addition:

- delayed property access and the non-sequential construction of towers led to other greater than anticipated engineering resource requirements;

- some initial tower designs had constructability problems and the consequential changes to the construction plans added some potentially avoidable minor costs;
- for safety reasons, the Alliance determined that it was necessary to construct fully engineered crane pads for safe tower erection and although the target outturn cost did include an allowance (approximately $2.6 million) for engineering and testing crane pads, it did not budget for fully engineered crane pads at each site; and
- the extent of temporary works, such as batters and retaining walls, was significantly under-estimated, partly due to lack of opportunity to survey sites prior to preparation of the GUP estimate.

8.21 Indirect costs and consumables

Table 8-11: indirect costs

Cost Element Description	Original TCE	Approved & re-measurable Scope Changes TCE Change	Budget	Anticipated Actual Direct Costs	Variance to Budget
INDIRECT COSTS (Includes office, yard, mobilisation, training and project management – see below)	32.8	4.3	37.1	49.8	12.7
CONSUMABLES	4.8	-0.3	4.4	10.5	6.1

The delay to commencing the overhead line construction works caused by the prolonged BoI process lead to the Alliance engaging additional resources to complete works by the system need date. Having larger crews meant increases in labour costs for accommodation, visas etc, and a larger office space and vehicle fleet which in addition to the set-up cost, resulted in higher running costs.[84]

The indirect costs were efficiently managed and reasonably incurred. For example, the project head office was located in Hamilton, the approximate middle of the line route, to reduce travel distances and cost in circumstances where property access along the line route was not sequential.

In addition:

- the cost of consumables was managed by a competitive tender process with multiple quotes and an operations manager to strictly manage costs; and
- costs were recovered to the extent possible by robust processes for selling project assets such as vehicles and equipment at the end of the project.

84 1650 people worked on the overhead lines construction phase of the NIGU Project.

Despite the cost increases on account of delays to the project, on a relative basis (i.e. as a percentage of total NIGU Project costs), actual indirect costs were approximately 15% of total NIGU Project costs, as anticipated.

8.22 General mitigation strategies

We constantly looked for ways to improve performance and minimise costs. Where possible, initiatives were implemented to improve efficiency and work methods, and to save overall costs for the overhead lines works for the NIGU Project.

The following are examples of how we minimised costs.

- There was a significant level of information exchange between the Transpower Property Group and the Alliance as to progress with securing property rights. A detailed spreadsheet showed progress by wiring section and made predictions looking forward. This ensured that the Alliance could programme construction works for the overhead transmission line in the most efficient manner possible, notwithstanding limitations on access.
- Transpower commissioned additional foundation testing to reduce the geotechnical uncertainty associated with the limited number of initial site inspections, thereby reducing the risks around foundation design and cost.
- The Alliance commissioned external reports from expert engineers to review and advise on improvements to construction productivity and risk management, particularly in relation to the delivery of foundations, tower erection and stringing works.[85]
- The Alliance used ICT hardware and systems innovatively. For example, it issued 30 “rugged” tablet devices to wiring crews to store construction information for stringing work which produced the following benefits:
    - a large reduction in time and cost to produce, keep up to date and distribute drawings and construction information to the field staff;
    - quick and easy sharing of pictures from site to gain engineering advice;
    - internet connectivity enabled team leaders/supervisors to download current information and communicate with each other including tablet-to-tablet video conferencing; and
    - device tracking was set up to support safety tracking of work crews..
- Easement terms required the removal and reinstatement of access roads, crane pads etc. Some landowners subsequently expressed an interest in retaining access tracks for their farm operations. To reduce the cost and risk associated with performing reinstatement works, landowners were approached with a financial offer in lieu of physical reinstatement works that was significantly less than the cost of the works themselves. Take up has been approximately 40%, resulting in cost savings to the NIGU Project of approximately $0.7 million.

85 The Alliance commissioned separate reports by KM&T on foundations, tower erection and stringing works.

8.22.1 Use of alliance contracting

Transpower used an alliance approach to manage the risk of designing, procuring and constructing its overhead transmission line. Both Transpower and the other appliance participants had a stake in the cost outcomes of the project.

If the “full” profit and overhead amount had been applied to the actual costs incurred on the Alliance works, Transpower would have paid approximately $47.2 million instead of the approximately $18.8 million that Transpower expects to pay.

Transpower considers that, despite the commercial challenges during the project, an alliance model was the right procurement solution for the overhead line project. A more conventional design and construct model would almost certainly have led to a very high level of variations and claims, commercial dispute and delays.

8.23 Conclusion

The original GUP estimate for the 400kV overhead transmission line works for the NIGU Project was $340 million. While additional costs have been incurred, Transpower has mitigated these costs to the greatest extent possible.

Construction of the overhead line for the Project was extremely challenging, with suboptimal sequencing adversely impacting the cost of foundation, tower erection and conductor stringing works. In addition, poor geotechnical conditions (including the presence of tomos) required additional remediation and other works. The alliance contract model, and the project management and other cost controls we adopted, ensured that expenditure on delivering these works was reasonable and efficiently incurred in the circumstances.

We acknowledge, however, that as much as $18 million of additional cost could have been avoided had the necessary property rights been obtained earlier and/or the Project timetable allowed for more time to obtain them.

Delays caused by prolonged regulatory processes were out of Transpower’s control but it is acknowledged that had Transpower started planning earlier, some of this additional cost may have been avoided.

Accordingly, we consider that all the expenditure on the overhead line works was, in the circumstances, reasonable and efficiently incurred and that the Commission should increase the MCA to allow Transpower to recover all costs. However, we will not recover (and receive a return on) more than $876 million in total from customers. The $876m total excludes the $18 million we consider could have been avoided had we started planning earlier.

9 Underground cable costs

($150m expenditure against budget of $158m)

9.1 Summary

Table 9-12: Cable costs

	Description	Amount	Variance
October 2006	GUP estimate (P90)	$157.8m	-
July 2013	Forecast End Cost	$150.4m	-$7.4m

The underground cable programme of works for the NIGU Project involved the installation of two new 220kV underground cable circuits from Brownhill substation to Pakuranga substation. The cables transmit electricity that has been transported to the Brownhill substation by overhead line from Whakamaru.

The scope of the underground cables project covered the manufacture, design, installation, commissioning and project management of the two underground cable circuits.

All components of the underground cable programme of works have been completed on time and within the Electricity Commission approved budget.

As we discuss in this section, cost savings in a number of areas were identified and obtained for the Project. However some difficulties were encountered during the works, which resulted in additional and unanticipated cost. Because of this, most of the contingency for the works was used.

We consider all expenditure on the underground cables programme of works was reasonable and efficiently incurred.

9.2 Scope of works

The NIGU Project included the installation of two new 220 kV underground cables, to connect the new Brownhill-Whakamaru line at Brownhill to our Pakuranga substation.

The Brownhill-Whakamaru line has a capacity of 2700MVA, but the Brownhill-Pakuranga cables installed only have a capacity of approximately 1300MVA.

When required, two more cables will be installed, from Brownhill to Otahuhu.

This approach stages the investment required and, by splitting the supply between Pakuranga and Otahuhu, provides diversity.

The Brownhill-Pakuranga cables mostly follow a road route (including both formed and paper roads) to Pakuranga, with a total length of approximately 11km per cable.

This presented many challenges, as we had not installed such a length of new cable before.

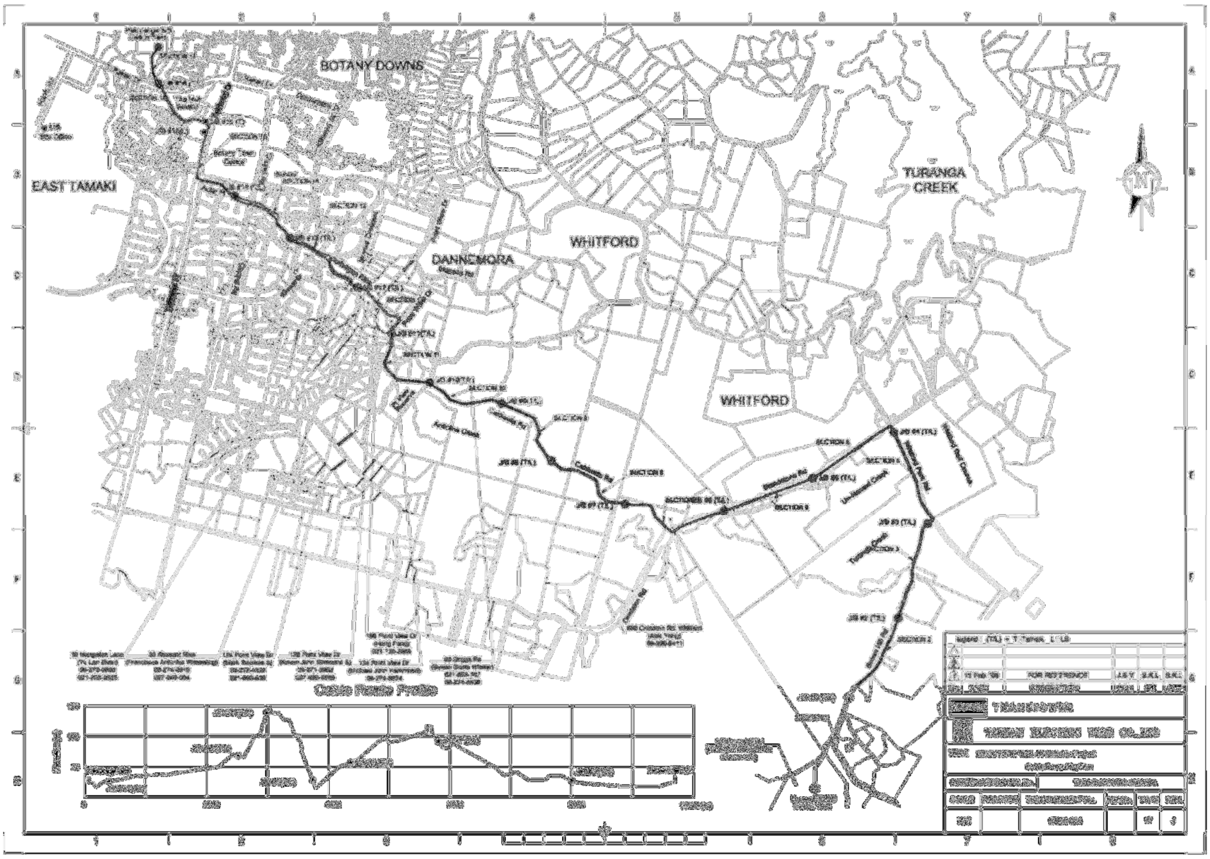
The project covered all work, plant, equipment and materials required to design, manufacture, test, deliver to site, joint, install, test and commission the cable circuits, and some enabling road works.

The key components of this complex project were as follows:

- survey of the cable route to determine, amongst other aspects, the positioning of actual cable lengths and the earth and civil works required;
- the design of cable installation arrangements and requirements for cable joints and terminations to meet magnetic field, thermal, thermo-mechanical, electro-mechanical force and seismic requirements and provide special installation features to mitigate the effects of ground settlement, mechanical forces and movements;
- application for resource consents from regional council and other authorities for the required works;
- upgrading of roads and bridges as required;
- preparing the existing Arapuni-Pakuranga 110kV tunnel for the entry of 220kV cables into Pakuranga;
- design and installation of the complete cable system (including all cable supporting structures) to meet the specified reliability requirements and to facilitate maintenance and repairs and minimise outage time;
- supply and delivery to site of the following:
  - 220 kV cable, joints, terminations and all other equipment that will form part of the cable circuits (including support stands for outdoor sealing ends);
  - 220 kV cable temperature monitoring system;
  - fibre optic cable for telecommunication purposes;
  - ducts for fibre optic cables including a spare duct;
  - specified spares;
  - other recommended spares;
  - special tools, test equipment and instruments required for installation, and site acceptance tests;
- all civil works required for installation of the cable circuits including foundation pads for outdoor sealing ends;
- cable laying and final positioning of cables including installation of cable supports, cable cleats and other fastenings;[86]
- all jointing work, including sheath bonding and connections to link boxes, earthing points, telecommunication and DTS cables; and
- pre-commissioning and acceptance testing of the installed cables, earthing and bonding system and temperature measurement system.

86 This included installation of ducts for fibre optic cables, backfilling of direct buried cables and reinstatement of roads and ground cover.

Figure 9-1: Brownhill-Pakuranga cable route



9.3 Competitive tendering approach

9.3.1 Single contract approach

We engaged Beca in 2005 to assist with the development of an implementation strategy for the full NIGU Project programme of works. For the underground cables project, a key recommendation from Beca was the use of a design, supply and install contract.[87]

A single contract approach was recommended because underground cables are a technically complex asset, and if the asset is to provide its full potential capability during service then each sub group (design, manufacture and installation) needs to perform its function to high levels to achieve that capability. This was best achieved by a single supplier.

The proposed strategy was reviewed internally and then externally by Evans & Peck in August 2005, who concluded that the strategy proposed by Beca for the underground cable project was sound.[88]

87 Beca, Implementation Strategy: North Island 400kV Grid Upgrade, July 2005 – supporting document 9.1.

88 Evans & Peck, Project Implementation Strategy Review, August 2005 – supporting document 9.2.

9.3.2 Competitive tender for single contract

A competitive tender was used to ensure that the costs for the underground cables were competitive and minimised to the extent possible.

The tender specification was reviewed internally and by Cable Consulting International. The draft commercial conditions were also circulated to manufacturers for comment and amendments made as a result.

In 2005/2006, we used an open Registration of Interest (**ROI**) process to identify parties with the capability to deliver the underground cable works. The ROI and associated prequalification process resulted in 10 parties being invited to submit tenders.

At tender close (September 2008), seven bids had been received.

Four preferred parties subsequently submitted a Best And Final Offer (**BAFO**). Some price reductions were achieved as a result of using the BAFO process. Following evaluation of the BAFO tenders, two parties were shortlisted, and meetings were held with each party.

At the conclusion of this process the Taihan Electric Wire Co. Ltd and LS Cable Ltd consortium offer was determined to best satisfy the evaluation criteria of being the lowest cost acceptable risk tender. Following Transpower senior management and Transpower Board approval the contract was awarded in September 2009 for $111.2 million (this contract price reduced to $109.6 million once materials had been ordered and commodity prices confirmed).

When other expected expenditure related to the project was added to the contract price (for example, for IDC), the total price for the project was $156.7 million. This was just lower than the GUP approved amount of $158 million.

9.4 Board of Inquiry decision

In June 2009, a draft BoI decision was received which indicated no major objection to the underground cables work programme of the NIGU Project. This decision enabled the Transpower Board to approve the cable tender.

Additional landscaping and slope stabilisation were required to meet the BoI conditions and to bring the land around Brownhill substation up to a standard for sustainable farming. The extent of landscaping required was underestimated during the preparation of the budget.

9.4.1 Project management and cost controls

Initially, these works were project managed in accordance with the Programme Management Plan for NIGU and standard Transpower BAU processes.

Later, a project manager (Beca), a construction manager (SKM) and a site inspector (SKM) were appointed.

9.5 Financial performance

Table 9-2: Forecast End Cost Brownhill-Pakuranga cables

$ million	**Actuals**	**Forecast**	**Forecast End Cost**
BOI apportionment	0.8	0.0	0.8
Design	1.9	0.0	2.0
Supply	2.8	0.0	2.8
- Miscellaneous and Test Set	1.9	0.0	1.9
- ARI-PAK Tunnel Liner Supply	0.8	0.0	0.8
Construction	6.1	0.0	6.1
- Miscellaneous and site clearing	0.5	0.0	0.5
- Landslip Caldwells Road - Extra costs.	5.6	0.0	5.6
UGC Design supply and install	114.2	0.7	114.9
- Contract value including variations and claims	114.2	0.2	114.4
- Provisioning for other payments	0.0	0.5	0.5
Project management	10.5	0.5	11.0
- Employee time	5.4	0.1	5.5
- Legal Probity and Consultants	0.7	0.0	0.7
- Insurance	0.7	0.0	0.7
- QA	0.8	0.0	0.8
- Owners Engineer	2.5	0.2	2.7
- Environmental	0.4	0.2	0.6
Issues	0.1	0.8	0.8
- Auckland Transport Road Easement	0.0	0.0	0.0
- BHL-OTA Cable Route Engineering etc	0.1	0.5	0.6
- Miscellaneous Landscaping	0.0	0.3	0.3
Defined Risks	0.2	0.8	0.9
- Sandstone Road Retaining Wall	0.0	0.7	0.7
- Enabling wks	0.1	0.1	0.2
IDC	10.9	0.0	10.9
TOTALS	**147.5**	**2.9**	**150.4**

We forecast that the underground cable project will be completed for $150.4 million ($2.9 million of expenditure is still required), against the Electricity Commission approved budget of $157.8 million, an overall underspend of $7.4 million.

There were a number of unexpected costs arising from changes to the specifics of the works as contemplated by the GUP and the Electricity Commission, additional IDC, and risk events materialising. The costs were not reasonably foreseeable at the time the GUP was approved by the Electricity Commission, and Transpower made all reasonable efforts to minimise the additional costs incurred, as discussed in the sections below.

There were some cost savings as well. As we discuss below, the savings arose from a decision not to install water cooling capability for the underground cables. Transpower made this decision after receiving advice that more cost effective options were capable of achieving similar results.

We discuss briefly below the factors that gave rise to additional costs or cost savings.

9.5.1 Additional costs incurred

Change to the Cable Route (+$10.0m)

In the aftermath of the “d-shackle” incident that caused the major outage at the Otahuhu substation in June 2006, we sought to adopt greater diversity of supply routes into major metropolitan areas, in particular into Auckland. This prudent planning approach reduces the risk of a major outage due to a localised event impacting on several lines.

To ensure route diversity for the 220 kV cables out of Brownhill a number of physically diverse routes were investigated. Two routes were identified:

- via Regis Park and land owned by Transpower; and
- via Sandstone Rd, with this route being about 1.0 km longer.

The Regis Park route from the Brownhill substation site was secured in perpetuity by landowner agreements and property purchases in the area between the Brownhill substation site and Ormiston Rd, but the Sandstone Rd route could not be secured for the longer term and it was effectively ‘first come first served’ for any utility wanting to use the route.

The GUP costing was based on the shorter distance via Regis Park, but it was decided that the Sandstone Rd route should be used for this first set of cables as there was a real risk that this route may not be available or viable in the future. The ability to install at least four cables from Brownhill to the north was a critical factor in the selection of Brownhill as the transition station site.

The additional cost of installing the cable along the longer route was approximately $10 million.

Brownhill Road Upgrade (+ $2.1m)

Because of the change in cable route, installation of two underground cable circuits were required to be installed in Brownhill Road – a rural unsealed lane used by local landowners. This was a major local issue during the planning stages and it was decided to upgrade Brownhill Road and the stream bridge near the Brownhill transition station boundary. This would minimise future disruption to the community and manage future risk of the cable being damaged, should the road be upgraded in the future.

The road was upgraded a two-lane sealed road, which required moving distribution power poles, cut and fill , including new retaining walls along the 3.8 km long road. The whole site was environmentally sensitive due to the presence of an ephemeral stream parallel to the road along its whole length. The bridge was completely reconstructed to full state highway standard in order to transport 400/220 kV interconnecting transformers into the Brownhill substation site when the transmission line is upgraded to 400 kV.

The total cost of the Brownhill Road upgrade works added $2.1 million to the costs of the underground cable works.

High Voltage Test Set (+ $1.4m)

A high voltage test set was required for the underground cable project. The approved GUP was based on Transpower hiring this equipment. However we subsequently determined that it would be very difficult to hire this equipment from other utilities as there is only one unit in Australia and none in New Zealand.

Given the amount of cable work planned by Transpower during 2010-2013 (including the major NAaN cables project), it was decided to buy a test set for use on a number of projects. This test set has been used for high voltage testing of cables for the Otahuhu Diversity Project, the NIGU cables and is currently being used for the NAaN cables project. For internal accounting purposes, we cannot allocate charges to each cable project, and all charges for its purchase have been allocated to the NIGU underground cable project.

The additional cost of $1.4 million is the difference between the cost of purchasing, rather than hiring, the equipment. Purchase of this equipment was essential for completion of the project, and efficiently completed through competitive tender.

Slope Stabilisation (+ $7.2m)

a) Caldwells Road (+$5.4m)

Caldwells Road is a paper road through farmland in the Whitford area adjacent to Dannemora. A substantial slip was discovered on the cable route along this road, adjacent to the Spong/Wilmer property.

This required mitigation works to stabilise the cables for a 1 in 500 year seismic event.

b) Sandstone Road (+$1.8m)

Sandstone Road is a three lane feeder road to rural south west Auckland with a low but continuous gradient over the section traversed by the cables. It incorporates an embankment in the lower part and a cut as it gets near the top, close to the intersection with Caldwells Road. Because it is one of several alternative arterial routes in the area, the design of the embankment is for a much lesser earthquake event than that required for the cable asset. The cost of works to improve the stability of the embankment to endure a 1 in 500 year seismic event is estimated to be $1.8 million. This cost is included in our forecast end cost, but the works are still in progress.

Tunnel Civil Works (+ $1.9m)

The project included re-use of an existing cable tunnel, previously used for the Arapuni-Pakuranga 110 kV circuit entry to Pakuranga.

During removal of the old 110kV cables from the cable tunnel, cracks were found in the tunnel structure.

It is thought that the cracks have resulted from increased overburden and the use of heavy trucks since the 110kV cable circuit was completed.

As the faults would be difficult to remedy once the underground cables were installed, the tunnel was strengthened by the insertion of 20mm circular steel liners that were welded in place and grouted to stop further stress on the concrete tunnel.

The cost of these works was $1.9 million.

Caldwells Rd West Landslip Cable Rerouting and Mangemangemoa Stream Works (+ $0.37m)

An extra cost of $0.37 million was incurred to reroute cable trenches to provide extra drainage and carryout more extensive works on the Mangemangemoa stream culvert.

This cost was not anticipated as no geotechnical investigations had been done in the stream bed and, when opened up, it became clear that the ground was soft and of poor bearing strength for a significant depth, and that it would need to be removed and backfilled.

Cost savings achieved

Cable Cooling (- $7.0 m)

In the approved GUP there was an allowance to install water cooling on the cables in the future to increase the heat transfer out of the cables, thereby increasing the capacity of the cables to transfer power. This would have required Transpower to undertake a water cooling system study and place pipes in the graded cement/ aggregate backfill which could be easily accessed at a later date.

A decision was made to remove the water cooling capability from the project scope for engineering reasons. Experience of water cooled cable systems in Europe has been poor. The reliance on electro-mechanical systems to achieve the circuit capacity is at odds with the fundamental reliability requirements for a high voltage transmission cable system.

Analysis of alternatives identified that it would be more economical to maximise the rating of the cables through conventional means (larger conductor and use of high thermal conductivity trench backfill) and to advance the installation of future cables to Otahuhu by a few years, than to invest in water cooling systems.

10 Deferral Projects

($38m expenditure against $49m budget)

10.1 Summary

Table 10-13: Deferral project costs

Date	Description	Amount	Variance
October 2006	GUP estimate (P90)	$49.4m	-
July 2013	Final Cost	$38.2m	-$11.2m

The Deferral Projects were:

- construction of a new switching station at Drury;
- thermal uprating of the Huntly-Hamilton-Whakamaru section of the Otahuhu–Whakamaru C line; and
- installation of 350 MVar static compensation at Otahuhu substation.

These projects enabled a delay in the system need date for the new line, from 2010 to 2013. They were approved by the Electricity Commission as part of the overall NIGU Project.

All three deferral projects were completed on time and under budget. We consider that all costs incurred on these deferral projects were reasonable and efficiently incurred. An overview of how the projects were managed and an explanation of the costs incurred for these projects (compared against initial budgets) is set out below.

10.1.1 Drury Switching station

Table 10-14: Drury switching station costs

Date	Description	Amount	Variance
October 2006	GUP estimate (P90)	$30.8m	-
April 2008	PAD	$22.9m	
July 2013	Final Cost	$20.3m	-$10.5m

Overview of works

The Drury switching station works comprised the procurement, construction and commissioning of a 220 kV switching station. This provided for better load sharing between the existing lines into Auckland and improved diversity in the event of the loss of one or more transmission circuits.

The Drury switching station is a new facility built on a greenfield site.

Figure 10-1: Drury switching station

Over the period of the works, there were zero safety incidents, and the project was completed six months earlier and under the budget contemplated by the PAD.

Contract award process

There were separate lump sum fixed price contracts for each of design, earthworks and civil/buildings, electrical installation and commissioning, and overhead line diversion works. We procured equipment through our regular panel contract suppliers. Project management and contract administration costs were higher than forecast, but this was because the work was broken into small sections. Ultimately, this approach resulted in lower costs overall. Time savings were made by overlapping some of the contracts.

Planning and resourcing

During the planning stage, a constructability/ risk review was held to establish the minimum number and duration of outages required to avoid commissioning complications.

Transpower construction projects are normally carried out during the summer months when it is easier to get outages due to lower electricity demand. With a number of other projects occurring at the same time (Otahuhu GIS project, Otahuhu–Whakamaru line work, Drury and Marsden projects), planning within the Projects group was essential to ensure contractor resources such as technicians and transmission line crews were available. Although some shortages were experienced, use of overtime and moving staff from project to project enabled work deadlines to be achieved.

The final contract was completed 15% over the awarded contract price but this was still within the project's allocated budget. The increased cost was primarily due to under-estimation of the transmission lines cost. It was identified as the project progressed, that additional work would be required for strengthening of tower foundations.

These works were project managed in accordance with the Programme Management Plan for NIGU and standard Transpower BAU processes. We successfully adhered to our communication plan, which was important when co-ordinating the range of contracts at issue, especially when those contracts overlapped. Additionally, our early engagement with stakeholders minimised opposition to the project works, and our continued engagement with stakeholders was key to the overall success of the project.

Financial performance of the project works

The GUP maximum approved cost for these works was $30.8m, however a later (April 2008) PAD re-estimated this at a lower amount of $22.9m. This included for the purchase of the Drury property on which the switching station is sited. The final cost of the Drury property was $5.7 million.

The balance of the approved cost ($25.1 million in the GUP but $20.4m in the PAD) was for design, consenting and, construction of the switching station itself and the line to tie it with the grid. The final cost of these works was $14.6 million, over $10 million below the GUP budget.

The costs savings were across most aspects of the project:

Table 10-3: Drury cost savings

Cost saving area	Amount saved versus original GUP
Transmission line	$1.5m
Primary equipment	$2.0m
Civil works	$1.8m
Bus zone protection	$0.9m
Project management	$1.3m
Environmental works	$0.2m
Miscellaneous	$1.0m
Contingency	$1.8m

The project was well managed, but it is clear the original cost estimate was high. There were no substantive changes in the functional scope following the GUP approval. We identified a cheaper alternative that provided the same functional outcome – installing a new breed ‘breaker and a half’ switching station. We had first installed this type of switching station at Ohinewai, however the GUP estimate for the NIGU works predated this build. We therefore used our new experience to reduce the cost of delivering Drury.

10.1.2 Otahuhu-Whakamaru C line thermal upgrade

Table 10-4: Otahuhu-Whakamaru C line thermal upgrade costs

Date	Description	Amount	Variance
October 2006	GUP estimate (P90)	\$6.0m	-
December 2008	PAD	\$11.5m	
July 2013	Final Cost	\$7.4m	\$1.4m

Overview of works

During the NIGU investigation, we identified that we could improve the load capacity on the existing lines into Auckland by thermally uprating the 220 kV circuits between Whakamaru, Hamilton and Ohinewai (on the Otahuhu–Whakamaru C and Hamilton Deviation A lines). These works were required to be carried out by April 2011.

This project involved considerable site investigations, particularly to assess potential ground clearance violations when the operating temperature of the circuits was increased from 50^{0}C to 80^{0}C. All the up-rated circuits were commissioned on time on 2 April 2011 with sections being commissioned in November 2010 and January 2011.

Contract award process

Project delivery was split into work packages, which were appropriately sequenced to achieve efficient delivery of the project works. To help ensure competitive pricing across the work packages, the major contracts for these works were awarded as separate fixed price contracts based on closed tendering to our regular maintenance contractors, who were the only contractors qualified for this work.

Several low value packages were awarded on a sole source basis, but at prices that were considered reasonable compared to the competitively bid packages.

There were two major contracts as part of the Tactical Thermal Upgrade (**TTU**) Project:

- Otahuhu–Whakamaru C TTU Main site works (parts 1 and 2)..

This was a contract for the main site works required for the thermal upgrade project, involving the line work required to raise the conductors by different techniques (for instance, by floating strain conversions or Akimbo arm conversions at 49 tower sites).

The scope of work was split into two packages to allow for the possibility that the work could be awarded to two separate contractors if necessary, because of timeframe or resource issues.

Following a registration of interest process, tenders were sent to three potential suppliers. Transpower considered these bidders had the necessary resources, capability and proven track record to undertake the necessary works.

Electrix Ltd won the tender and was awarded both packages of work.

The final amount incurred for the works was higher than the award value by $0.3million. This arose through an addition to the scope of work. At the time of tendering, the scope of vegetation work was not known and it was considered more efficient to vary the scope of the contract to include this work, as Electrix are also the maintenance contractor in this region. Other scope changes related to work required at additional tower sites and the impact of outage timeframes and risk mitigation measures.

- Otahuhu–Whakamaru C TTU Joint replacement – C/Otahuhu–Whakamaru C/3206

This was a contract for the replacement of conductor joints that were identified from previous live-line testing as having an out of tolerance electrical resistance. The line work can only be carried out during an outage on the circuit, with the line de-energised.

Transpower again followed a registration of interest process and narrowed selection to a final tender round involving three companies who had the resources and capability, as well as a proven track record.

The final cost incurred was $1.2 million, $0.2 million higher than the contract award price due to scope changes including for; additional joints needing replacement, removal of joints from the scope, additional inspections and re-testing being required, addressing property issues and short notice changes in the outage programme.

Planning and resourcing

A System Project Overview was prepared for the project, and Commissioning Plans were used in relation to the changes being made to the line, and for outage planning.

The works were project managed in accordance with the Programme Management Plan for NIGU and standard Transpower BAU processes. Ongoing reporting of project risks was undertaken through a Monthly Project Report. The most significant project risks identified and managed in relation to each contract, and stage of the site works, were as follows:

- landowner relationships and access to private property;
- outage availability to carry out the works; and
- availability of contractor resources for carrying out site works.

A proactive approach to managing landowner relationships was adopted because property access was identified as a significant risk. The project team made initial contact with affected property owners ahead of contractors giving notification of access. This assisted in identifying and resolving any potential issues before access was required.

Due to the critical nature of the relevant circuits, as much as possible of the line work was carried out using live-line techniques.

A communication plan was also implemented in relation to risk mitigation for outages affecting the security of supply to Hamilton substation.

Financial performance of the project works

The original GUP estimate for this project was $6.0 million. A closer look at the scope of the project identified that this amount was insufficient to undertake the works. In particular there was little information at the time of the GUP estimate as to whether purchase of easements would be required to do the work and the extent of the work until access to the line could be obtained and a condition assessment could be completed. A revised budget of $11.5 million was established and a PAD approved in December 2008 based on updated information.

During project delivery, savings were made on most of the peripheral items (as summarised in Table 10-5 below). The main part of the project, that is the construction and joint works, required most (93%) of its allocated budget.

Table 10-5: OTA-WHK C TTU cost savings against the PAD were:

Cost saving area	Amount saved versus PAD
Investigations	$0.4m
Property Easement	$0.8m
Inspection and Testing	$0.4m
Construction and joint works	$0.4m, Budget 5.9 m, actual $5.5m
Substation works	-$0.1m
Project management. under-crossings, vegetation etc.	$0.8m
Capitalised Interest	$0.3m
Contingency	$1.1m , not required

Compared to the revised budget, savings included:

- The budget of $0.7 million for investigations which took place mostly in 2008 cost $0.3m, a saving of 0.4 million.
- Only $40,000 of a budget of $0.8 million was used for easement and landowner agreements. Access to carry out the works was secured through Land Access Protocol Agreements (LAPA's), and case by case agreements to carry out minor access works.
- Fly-by inspection and joint testing works were budgeted to cost $1.2 million and ended up costing $0.8 million – resulting in a saving of $0.4 million.
- Stage 1 and 2 of the line contractor site works had a combined budget of $5.9 million and ended up costing $5.5 million – resulting in a saving of $0.4 million.
- The delivery of other works (including underground works, vegetation, Transpower management, and project management) was completed for a cost of $0.2 million versus a budget of $1.0 million. The vegetation work was carried out at a low incremental cost within another contract. The under-crossing works were completed for less than estimated. The project management costs were spread out and absorbed by other items, as were capitalised interest charges.
- Capitalised interest was $0.3 million less than the budget of $0.7 million
- In addition, the risk management contingency allowance of $1.1 million (including potential consenting and property costs) was not used.

The substation upgrade works required were carried out in a series of small projects at the Whakamaru, Hamilton and Ohinewai sites. The final costs for the works were $0.35 million, versus a budget of $0.28 million. The $70k cost increase is attributed to the level of coordination and planning required to coordinate these works with outages.

10.1.3 Otahuhu, Penrose and Hepburn Road Capacitor Banks

Table 10-6: Otahuhu, Penrose and Hepburn Road Capacitor Banks costs

Date	Description	Amount	Variance
October 2006	GUP estimate (P90)	$12.6m	-
April 2009	PAD OTA 2x 100 Mvar Cap Banks	$ 6.2m	
August 2007	PAD Hepburn Rd (50 Mvar)	$ 1.8m	
August 2007	Penrose (100 Mvar) Cap Banks	$ 2.9m	
July 2013	Final Cost (OTA $5.8m; HEP $1.6m and PEN $2.6m)	$10.0m	-$2.6m

Overview of works

The original GUP approved by the Electricity Commission in 2007 included the installation of 350 MVAr of new static reactive plant at Otahuhu substation as one of the deferral projects.

Although the GUP specified installation at Otahuhu, it was signalled that we would undertake a study prior to installation, in order to optimise the location of the static reactive plant.

That study concluded that installation of 200MVAr at Otahuhu, 100MVAr at Penrose and 50MVAr at our Hepburn Road substations would provide better reactive support and this was implemented.

Otahuhu

At Otahuhu the project involved installation of two new 220 kV, 100 Mvar, earthed 'H-bridge' configuration capacitor banks on the new 220 kV AIS bus. The Otahuhu Diversity Project (ODP) was underway at the time, so for the purpose of efficient delivery of the works the capacitor banks were delivered as part of the ODP to ensure coordination of the workstreams and to utilise the ODP team for project management, design and installation.

The project was completed within the required timeframe, within budget and to acceptable quality.

Contract award process

An open RFP tender panel was used to appoint the capacitor bank equipment supply contract. The lowest cost tender was selected.

Project management

The project timing was concurrent with ODP construction. Rather than have two separate projects with associated interface issues we decided that the capacitor bank construction should be carried out as a scope change to the ODP, managed by the ODP project team using ODP procedures with design and installation by the design consultant and installation contractor already engaged on ODP.

The objective was to have the capacitor banks available for service for winter 2010. This was achieved, despite a significant scope change to include damping networks to prevent potential harmonic resonance. The original approved budget was $4.2 million and was provided for in the 2009 and 2010 capital budget. However, during 2008/9 it was identified that the high levels of reactive support in Transpower’s transmission network could result in problematically high harmonic currents and voltages. This necessitated a revision of the procurement specification to acquire mechanically switched capacitor banks with a damping network instead of the original plain mechanically switched capacitor banks. This resulted in an increase of $2.0 million.

Financial performance of the project works

The approved PAD budget of for this project was $6.2 million. Actual final costs were $5.8 million.

Risks were regularly reported and assessed through the monthly reporting process. Risk management processes were adopted by the contractors in relation to each contract and stage of the site works.

Penrose and Hepburn Road

The project at Penrose and Hepburn Road involved the installation of three 50MVar capacitor banks across the 110 kV buses – two at Penrose and one at Hepburn Road.

Four capacitor banks of the exact design to be used had already been installed over the previous 2-3 years in Auckland: hence a standard design for both the procurement and installation was able to be utilised.

Contract award process

Transpower nominated Maunsell as the design consultants for the design component work as they had earlier been awarded the contract to prepare the Transpower standard design for capacitor banks (including protection) and the standard design was anticipated to be completed prior to this project.

The tenderers for the installation contract were required to include the costs for Maunsell's services in their tender price.

The capacitor bank design, civil and installation contract was an open RFP tender panel with offers received from Electrix, Transfield Services and United Group. The contract was awarded to United Group Ltd for $1.47 million. Despite not being the lowest price but near to the lowest, strong consideration was given to the contractor’s proven prior experience having successfully installed capacitor banks at Bombay. In addition, timeframe for delivery of the Bombay Capacitor banks was similar to the timeframe expected to deliver both Penrose and Hepburn Rd Capacitor banks. The United Group offer also included placement of a senior Project Manager and two key members of the team responsible for delivering Bombay.

Financial performance of the project works

The approved budget for the Penrose works was $2.9 million. Actual final costs were $2.60 million.

The approved budget for the Hepburn Road works was $1.8 million. Actual final costs were $1.6 million.

Both projects were completed under budget and on time (30 May 2008).

11 Investigation and environmental consenting costs

($39m expenditure against $38m budget)

11.1 Summary

Table 11-15: Investigation and environmental consenting costs

Date	Description	Amount	Variance
October 2006	GUP estimate (P90)	$37.7m	-
July 2013	Forecast End Cost	$38.6m	$0.9m

The investigations and environmental consenting programme of works involved:

- Environmental investigations up until the Notice of Requirement (**NOR**) were lodged, including identification of the preferred route, location of substations and transition stations, to meet the requirements under the Resource Management Act 1991. A considerable amount of conceptual and detailed engineering investigations were required before formal planning documents could be lodged seeking resource consent, including consideration of alternative options;
- Environmental planning, including the costs of gaining designations and resource consents, for the NIGU works (not including the deferral works to be commissioned by 2010); and
- General investigations and project management of the NIGU programme of works as a whole (but not including specific project management for the individual sub-projects for NIGU).[89]

The investigations and environmental consenting programme of works resulted in expenditure of $39 million against a GUP estimate of $38 million. The cost increase was due to higher than anticipated costs arising from the BoI. We consider all expenditure on investigations and environmental consenting was reasonable and efficiently incurred.

11.2 Works undertaken for investigation and environmental consenting process

Gaining resource consents for the NIGU Project as quickly as possible was critical. We had to carry out comprehensive preliminary investigations of the intended works, including considering alternative options for various aspects of the works. It was also important that this be

89 The GUP budget also included a small amount ($0.07 million) for project management of the uprating of the Otahuhu-Pakuranga line to 220kV, which was managed as part of the Otahuhu substation works. All other project management activity for the NIGU Project works (and associated budget) was allocated to the relevant sub-project. Accordingly, the costs were not managed under this investigations and environmental cost category.

comprehensive to allow for an efficient hearing process, without the need to refer any outstanding matters back for further consent.

11.2.1 Board of inquiry process

When we prepared the scope of works and GUP estimate for the investigation and environmental consenting process, we assumed that the "normal" resource consent hearing process in the Environment Court would be followed, with evidence preparation and overall case management based on specific appeal points. Reflecting this, the GUP budget assumed approximately a base cost of \$5.5 million (in \$2006) for resource consents and designations.

However, consideration of the Notice of Requirement for a Designation and various resource consent applications was "called-in" and considered by a BoI under a new statutory process enacted after the GUP estimates were compiled. While this allowed for the public consultation on the designations and regional resource consents, it did not allow for pre-hearing determinations to narrow down the process to key issues. Rather the BoI process involved the preparation of a very wide range of detailed evidence and submissions.

This resulted in a more complex – and ultimately costly - process than the usual consenting process. In particular:

- All expert witnesses needed to attend whereas, in contrast, far fewer witnesses would be required to attend and be cross-examined through the ordinary consenting processes;
- Transpower staff were cross-examined at the BoI - this would not have happened through the ordinary consenting process;
- Submitters were permitted (by the Board) to cross-examine about matters which were essentially a re-litigation of matters already considered by, and within the jurisdiction of, the Electricity Commission;
- Transpower needed to pay the administrative costs of the Board; and
- A longer hearing process also increased Transpower's own administrative/resourcing costs.

Ultimately, approximately \$16.8 million was spent on the BoI, comprising:

- Board of Inquiry sitting costs (\$6.4 million);
- Environmental consultants, etc costs for circuit corridor (\$4.3 million);
- Technical design inputs (\$4.4 million); and
- Project management support (\$1.7 million).

These costs were incurred between this project cost centre and others.

11.3 Major contracts

Major contracts for environmental investigations were awarded based on a competitive tender, except where a sole source negotiated tender was awarded where this was appropriate given the past experience of the relevant tenderer.

We ran a tender process for the environmental investigation to determine possible routes for the new line. The successful tenderer for these works was also appointed to the second and third phase of this investigation given their knowledge from the first phase of the Project.

The second stage involved determining the position of the easements needed to construct the line and the completion of the documentation necessary to obtain resource consent for this. Costs escalated from our initial estimates for this component after the Electricity Commission declined the first GUP we submitted. Much of the project needed to be re-worked and we realised additional scrutiny of the environmental aspects of the project would be required.

The third phase involved environmental studies to be presented at the BoI. As the BoI process involved significantly greater volumes of evidence than we had anticipated, the final costs increased.

The scope of the legal work was unclear at the estimate stage as we had no prior knowledge of the BoI process or the number of submitters that would be involved. Our initial estimates were based on an Environment Court hearing involving 14 witnesses. However, as noted above, the process turned out to be much more extensive.

The costs were carefully managed and appropriate processes used throughout. We therefore believe the costs were reasonable under the circumstances and efficiently incurred.

11.4 Financial performance of the works

The original GUP budget assumed a breakdown for environmental and investigations works (and some minor project management costs) as follows.

Table 11-2: Environmental and investigation costs

Description	**P90**
NIGUP Environment and Consenting	$10.6m
Project Management (Otahuhu-Pakuranga upgrade)	$0.1m
Investigations	$27.0m
TOTAL	**$37.7m**

Actual costs incurred for investigations and environmental consenting works are set out below. Ultimately, cost management of the environmental investigation process merged with the Board of Inquiry process, meaning only a few specific environmental investigation costs have been itemised against the particular NIGU works.

Table 11-3: Environmental and investigation actual and forecast costs

	Description	Actual 26/6/13	Forecast End Cost
1.	NIGUP Otahuhu-Whakamaru C Thermal Upgrade (Investigations)	0.3	0.3
2.	Otahuhu 350 Static Comp Investigations Surge Arrestors	0.2	0.2
3.	Otahuhu-Whakamaru C Terminal Equipment Investigations	0.1	0.1
4.	Employee time	9.6	9.7
5.	Admin and General Expenses	0.7	0.7
6.	Project Implementation comprising: Brokerage costs for insurance for overhead line/underground cable commissioning staff (external)	0.4 0.2 0.2	0.4
7.	Environmental (Pre & Post BoI) comprising: Consultants Public Consultation Notice of Requirement Council costs Call Centre BoI (not included in BoI cost analysis) Visual Mitigation BoI Landscape mitigation	10.4 6.9 0.2 0.2 0.6 0.0 0.4 0.1 2.1	11.0
8.	Project Management Support including project management and property consultants	3.2	3.2
9.	Regulatory Approval Consultants	0.1	0.1
10.	Published communications	0.2	0.2
11.	Legal advice comprising: Judicial Review Project legal advice	0.7 0.2 0.5	0.7
12.	Resource Consents and Designation (BoI)	12.4	12.4
	TOTAL	**$38.4m**	**$39.2m**

11.5 Deloitte Energy Award for Environmental Excellence

Undertaking environmental investigations and obtaining resource consents for a project of this nature requires careful and respectful liaison with a wide range of stakeholders.

Our approach for the NIGU Project was recognised in 2012, when the Alliance won the Deloitte Energy Award for Environmental Excellence for work on the NIGU.

The project was a technical and environmental challenge - the size of the project meant we had to change the way we looked at our environmental systems to deliver the results. The project required involvement and liaison with nine councils, over 300 directly-affected landowners, and multiple government agencies and regulators. At times we had over 50 varying workstreams and over 300 kilometres of access tracks and roads on working farms being installed, involving the movement of 180,000m3 of earth. This provided some large environmental challenges to overcome.

The Deloitte Energy Award was the culmination of all the good work, starting with the lead up to the BoI and ending with reinstatement of access tracks which are now near completion.

12 Interest during construction

Table 12-1: Interest during construction costs

Date	Description	Amount	Variance
October 2006	GUP estimate (P90)	$80m	-
July 2013	Forecast End Cost	$77m	-$3m

12.1 Summary

In 2006, we calculated an estimate of IDC for the NIGU Project for the purposes of the amended GUP submitted to the Electricity Commission. IDC was assumed to accumulate until the entire project was complete and commissioned by the need date of 2013. The interest rate was assumed to be 7%.

In reality, the interest rate over the period 2006 to 2012, when the transmission line was actually commissioned, averaged 7.5%. Taken on its own, this would have increased IDC for the project by $6 million.

However, the nature of the project meant that many assets were created through the life of the project. For example easements, land and vehicles were all recognised as assets prior to the completion of the full project. The effect of this was to reduce IDC, and reduce the total project cost.

The project was also commissioned in late 2012 rather than 2013 and this avoided IDC costs in comparison to the original estimate.

The increase due to a higher than assumed interest rate and decreases due to early assetting and 2012 commissioning, largely offset each other, with actual IDC being approximately $77 million, slightly less than the GUP estimate.

12.2 Foreseeability of factor and Transpower's response

This was the first project of such a size that was completed by Transpower. It was the first to commission a significant volume of assets prior to final project completion. IDC is a function of spend, schedule, asset commissioning and interest rates. There was a strong focus on optimising the schedule and commissioning assets as the project progressed. We consider the actual IDC cost of $77 million to be reasonable and efficient.

13 Information about the effect of the amendment application

13.1 Implications of proposed amendment to the MCA on NIGU project outputs

The proposed amendment to the MCA itself has no implication for the approved major capex project outputs for the NIGU Project. As noted we are concurrently applying for a determination (to the extent necessary) by the Commission to approve certain changes to the approved major capex project outputs for the NIGU Project. However the applications for an increase in MCA, and separately for amendment to the approved major capex outputs, are not related in the sense that one does not arise as a consequence of the other.

13.2 Net electricity market benefit

13.2.1 Summary

We have repeated the grid investment test with the amounts we have actually spent on the NIGU project for property and the new transmission line and compared it to the original results we provided to the Electricity Commission in 2006.

Our analysis concludes that:

- the NIGU Project would still satisfy the GIT if these actual costs were used instead of the estimates relied upon in the analysis undertaken for the 2006 GUP;
- the electricity market benefits resulting from the NIGU Project remain substantially higher than the costs.

13.2.2 Analysis

Table 13-1 contains the original results from the GUP submitted to the Electricity Commission in 2006.

Table 13-1 – Original Grid Investment Test results, using 2006 pricing

2006 dollars (millions)	**220 kV** 2013 Whakamaru –Pakuranga	**400 kV** 2013 Whakamaru –Pakuranga	**Duplex** Otahuhu–Whakamaru A&B 2015
Mean capital cost (A)	687	682	737
Mean O&M costs (B)	24	25	21
Mean unserved energy cost (C)	0	0	0
Mean relative loss cost (D)	0	-1	60
Mean terminal benefit (F)	12	13	4
Strategic benefit (G)	0	-5	0
Mean NPV cost (A+B+C+D-F+G)	698	688	813
Difference v 220 kV, Expected Net Market Benefit	-	-10	115

13.2.3 NIGU Project would still satisfy the GIT using actual costs

The analysis, when compared in 2006 pricing, reveals no change in expected net market benefit when compared to the other alternative investment options.

In order to consider the expected net market cost now that we know the actual costs for the NIGU Project, we have only altered the capital costs in the grid investment test as we are not seeking any amendment to any other category of costs or benefit used in the test. We set out the results below in Table 15-2 with the increase in property acquisition and transmission line construction costs.

The actual capital cost of the 400 kV development plan has increased to $761 million in 2006 pricing. However, as the main source of the cost increases to the NIGU Project come from increases to the build of the transmission line and property costs, the cost of the alternative options also increase over the same analysis period as both alternatives would have been subject to similar geotechnical uncertainties and have required Transpower to acquire additional property rights. The first alternative, being the build of a new 220 kV line between Brownhill and Whakamaru, would have required obtaining two sets of property rights over the analysis period, leading to similar increases in costs to the 400 kV line actually constructed. The duplexing option, while involving less construction cost in the short-term, would also have required two new lines and hence two sets of property rights in the long run, in addition to property rights for the duplexing itself.[90]

Table 13-2 – Grid Investment test run with actual capital costs, using 2006 pricing

90 Electricity Commission, Final Decision on Transpower's North Island Grid Upgrade Proposal, (5 July 2007).at [4.3.19] to [4.3.21] – supporting document 3.4

2006 dollars (millions)	220 kV 2013 Whakamaru –Pakuranga	400 kV 2013 Whakamaru –Pakuranga	Duplex Otahuhu–Whakamaru A&B 2015
Mean capital cost (A)	765	761	845
Mean O&M costs (B)	27	29	24
Mean unserved energy cost (C)	0	0	0
Mean relative loss cost (D)	0	-1	60
Mean terminal benefit (F)	12	13	3
Strategic benefit (G)	0	-5	0
Mean NPV cost (A+B+C+D-F+G)	781	771	926
Difference v 220 kV, Expected Net Market Benefit	-	-10	145

13.2.4 Electricity market benefits of NIGU Project remain substantially higher than costs

When submitting the GUP in 2006, we did consider comparing the proposed investment option with a “do nothing” option. A ”do-nothing” option would have meant we would not carry out any investment into Auckland, and instead incur unserved energy, with the system operator pre-emptively shedding load at peak times from about 2010 to maintain a secure system.

The unserved energy and resultant costs were excessive,[91] so the “do nothing” alternative was discarded as it was not considered a reasonable alternative. Instead, the 220 kV option became the reference case by which to consider the 400 kV proposal and the next best alternative, duplexing of existing lines. The results indicated a net market cost of $688 million in 2006 prices,[92] being $10 million less than the 220 kV alternative and $115 less than the duplex option.

The analysis indicates that the approved NIGU project is still in the long term benefit of consumers; providing reliable electricity supply into the Auckland and upper North Island region at the lowest cost over the analysis period.

Commissioning of NIGUP has resulted in reduced transmission losses between Whakamaru and Auckland of between 30 and 40MW.

91 The 2005 GUP, subsequently withdrawn, quantified the expected unserved energy to cost $27.3 billion over the analysis period.

92 The grid investment test involves discounting the expected costs of the project and costs of any other project that are likely to occur as a result of the NIGU project over a 20 year period from the forecast commissioning date and compares these with other potential options. As the NIGU project involves what is referred to as a reliability investment (as opposed to an economic investment) the results will (ordinarily) be negative.

13.3 No change to the assets to be commissioned

Approval by the Commerce Commission of the proposed amendment to the MCA will not result in a change in the assets to be commissioned by Transpower for this Project. However, as noted we are concurrently applying for a determination (to the extent necessary) by the Commission to approve certain changes to the approved major capex project outputs for the NIGU Project.

13.4 No change to the functional capability of the grid

Approval by the Commerce Commission of the proposed amendment to the MCA will not result in a change in the functional capability of the grid.

13.5 No change to third party services (for non-transmission services)

Approval by the Commerce Commission of the proposed amendment to the MCA will not result in a change to any services provided by a third party (for non-transmission services).

13.6 No implications for other approved major capex projects

We do not consider the proposed amendment will have any implications for other major capex projects. Our cost estimation process has undergone continuing development since the NIGU Project was costed. In particular, more consideration now tends to be given to the risk profile around scope.

14 Evaluation of the application

14.1 Application is consistent with the Capex IM

This application is consistent with the Capex IM. In particular:

- This application has been submitted to the Commerce Commission in accordance with clause 3.3.4(1) of the Capex IM.
- We have complied with clause 7.4.2 of the Capex IM. Specifically:
  - The application has been sent to the Commerce Commission before the last working day of September after the disclosure year in which the Project was first commissioned (being before the last working day of September 2013); and
  - The application contains the information specified in Schedule H Division 1 of the Capex IM. Please refer to the table in Appendix 1 of this application that indicates where in the document the information specified can be found.

Because this application is consistent with the requirements of the Capex IM, we consider that the proposed amendment will promote the purpose of Part 4 of the Commerce Act 1986.[93] We elaborate on how this amendment promotes Part 4 below.

14.2 Proposed amendment promotes long-term interests of consumers

The amendment to the MCA is consistent with the purpose of Part 4 of the Commerce Act as it promotes the long-term interests of consumers by ensuring efficient investment that delivers net market benefits to consumers.

The NIGU project provides an efficient upgrade to meet the immediately foreseeable demands of electricity consumers in the upper North Island while providing capacity options for future needs. It thereby minimises the long-term costs to consumers by providing the greatest net market benefit when compared with other alternatives over the next 30 years or more.

As the Commerce Commission has previously recognised,[94] recovery of efficiently incurred costs under the Capex IM provides us with the incentive to invest for the long-term benefit of electricity consumers. While there might be short term gains to consumers if the Commission were to reject the recovery of additional expenditure incurred in relation to a major capex proposal, we would lack incentives to invest, innovate and improve efficiency if these costs were not able to be recovered. This is significant in the context of NIGU as the project was the largest investment of its kind since the 1960's and involved a number of contingencies. It was important that we

93 Commerce Commission, Decision on the Otahuhu Substation Diversity Project Major Capex Allowance Amendment [2013] NZCC 8, para A4, where the Commerce Commission observed that when an approved project is amended in accordance with the requirements of the Capex IM, the amendment will promote the purpose of Part 4 of the Commerce Act 1986 – supporting document 3.7.

94 Commerce Commission, Decision on the Otahuhu Substation Diversity Project Major Capex Allowance Amendment [2013] NZCC 8, para C12 – supporting document 3.7

consider the long term interest of consumers rather than simply concentrating on the immediate costs.

We also note that:

- the Capex IM recognises that it is difficult to estimate the costs of major capex projects in advance by providing a mechanism for an ex-post assessment of additional costs; and
- the Capex IM, together with the individual price-quality path provisions which apply to Transpower (of which the Capex IM forms part of), mean that compliance with the requirements of these determinations will, together, promote the objectives of the Part 4 Purpose.[95]

14.3 Data, analysis, and assumptions are fit for purpose

We also consider that the data, analysis, and assumptions underpinning this application are fit for the purpose of the Commerce Commission exercising its powers under Part 4 of the Commerce Act, including consideration as to the accuracy and reliability of data and the reasonableness of the assumptions and other matters of judgement. We have provided information in (and with) this application which demonstrates how the application is consistent with the Capex IM, including the basis for the proposed amendment to the MCA for the NIGU Project.

95 Commerce Commission Transpower Capital Expenditure Input Methodology Reasons Paper (31 January 2012) at para 1.3.7 and 1.3.8 –supporting document 3.11.

15 Chief Executive Certification

CHIEF EXECUTIVE OFFICER'S CERTIFICATION AS TO MAJOR CAPEX PROJECT AMENDMENT (NORTH ISLAND GRID UPGRADE PROJECT APPLICATION FOR INCREASE IN MAJOR CAPEX ALLOWANCE AND AMENDMENT TO THE APPROVED MAJOR CAPEX PROJECT OUTPUTS)

(Transpower Capital Expenditure Input Methodology Determination 2012 Part 9 Clause 9.3.1) (the **Capex IM**)

I, Patrick Clifford Strange, Chief Executive Officer of Transpower New Zealand Limited (**Transpower**) hereby certify, in relation to all information provided in accordance with Schedule H to the Capex IM with respect to the North Island Grid Upgrade Project Application for Increase in Major Capex Allowance and Amendment to the Approved Major Capex Project Outputs, that having made all reasonable enquiries, it is my belief that:

a) the information was derived from and accurately represents, in all material respects, the operations of Transpower; and
b) all parts of the major capex project to which the information relates have been approved in accordance with the applicable requirements of Transpower’s director and management approval policies; and
c) the application for increase in major capex allowance and amendment to the approved major capex project outputs complies, in all material respects, with the requirements of clause 7.4.2 of the Capex IM.

DATED: 30 September 2013

PATRICK CLIFFORD STRANGE

Appendix 1: Project Identification and Specifications

A.1.1 Project Identification and Specifications

The NIGU Project involved reinforcing the transmission link between the Central North Island and Auckland, through construction of a transmission line, underground cables and associated substation works (Whakamaru– Brownhill –Pakuranga).

We first submitted a GUP to the Electricity Commission in 2005. This identified that with the expected growth in electricity demand (as specified by the Electricity Commission), reliability of electricity supply for Auckland and Northland would be threatened by 2010 unless new generation was built in the region. Without new generation, the only feasible option was to build a new transmission line. The lead time to commission a new line is typically seven to ten years, so other options were also considered. The GUP therefore also included some deferral projects – projects which ensured reliable supply for Auckland and Northland from 2010 and which extended the need date for the new line out to 2013. The NIGU Project included the first significant line we had built since the 1980s and the first to be built since enactment of the Resource Management Act. To allow for delivery risks (potential consenting and construction delays), we developed a plan to deliver the new line in 2011.

There were delays during the approval process, but ultimately the NIGU Project was approved by the Electricity Commission in 2007. There was then a further delay as we worked through the environmental consenting process, but the line was successfully commissioned in October 2012.

A.1.2 Project Specifications

The NIGU Project is a programme of works which at time of approval was specified as the following[96]:

- Procure, construct, commission and operate a 220 kV switching station in the vicinity of Drury and upgrade the 220 kV Otahuhu – Whakamaru C line by 2010.
- Procure, construct, commission and operate 350 MVAr of new static reactive plant at Otahuhu substation by 2010.
- Procure, construct, commission and operate a new double-circuit, steel lattice tower, overhead transmission line of approximately 190km from a new substation near the existing Whakamaru substation to a new transition station in the vicinity of the South Auckland urban boundary that is capable of:
    - 220 kV operation;
    - future 400 kV operation of around 2700 MVA, subject to later Commission approval of and Transpower commissioning of 220 kV-400 kV transformers and

96 North Island Grid Upgrade Project Amended Proposal Application for Approval 20 October 2006, included as Attachment 1.1 in the supporting information included with this application.

associated switchyards near the existing Whakamaru substation and in the vicinity of the South Auckland urban boundary (i.e.at Brownhill).

- Procure, construct, commission and operate two underground cables from the new transition station in the vicinity of the South Auckland urban boundary to Pakuranga substation that:
    - are capable of 220 kV operation; and
    - have a continuous rating of around 660 MVA per set of cables
- Procure, construct, commission and operate the necessary substation / transition station facilities near the existing Whakamaru substation (Air Insulated Switchgear [AIS]), a transition station in the vicinity of the South Auckland urban boundary (AIS), and Pakuranga substation (Gas Insulated Switchgear [GIS]).
- Plan the works, including the acquisition of designations, consents and easements to allow for future upgrade to 400 kV operation through future addition of:
    - new 400/220 kV transformers and associated works near the existing Whakamaru substation to interconnect with the existing 220 kV system;
    - a new switchyard in the vicinity of the transition station with new 400/220 kV transformers and associated works; and
    - new overhead lines or underground cables to connect the new switchyard with the new transition station.
    - new 220 kV underground cables to Otahuhu substation.
    - extensions to the Otahuhu switchyard(s)
- Carry out the works necessary to convert and connect the existing 110 kV Otahuhu-Pakuranga line to 220 kV operation, for which it is already designed and consented;
- Dismantle the existing 110 kV Arapuni to Pakuranga transmission line
- Obtain designations, easements, resource consents and property purchases necessary for all the above works
- Plan for a commissioning date of 2011 for the major projects above to prudently allow for potential delays due to delivery, designation, consenting and easement risks.

The Electricity Commission approved recovery of actual expenditure on the NIGU Project up to a maximum of $824 million.

Appendix 2: Proposed Approach for Limiting Recovery to $876 million

While we are seeking an increase in the MCA for the NIGU Project to $894 million (on the basis that this represents reasonable and efficient expenditure), we intend to only recover (and receive a return on) $876 million, i.e. $18 million less than expenditure.

Our proposed approach to achieving this is as follows:

- to comply with the Transpower input methodologies, we will enter the NIGU assets into our regulatory asset base (RAB) in the normal way.
- as a consequence, actual costs will be reflected in the RAB values used to set revenues for RCP2 and beyond (i.e., from 2015/16)
- actual costs will also be reflected in *ex post* MAR wash up adjustments relating to 2012/13, 2013/14 and 2014/15 disclosure years (and applied to the 2014/15, 2015/16 and 2016/17 pricing years)
- for the 2014/15 pricing year we will reduce the AC revenue amount (used to set the interconnection rate under our transmission pricing methodology) by $4 million. This is approximately equivalent to the *ex post* excess revenue amounts for RCP1 (i.e., 2012/13 to 2014/15).
- we will then work with the Commission to ensure that revenues for the RCP2 period are adjusted in the price path determination such that, by the end of RCP2, we will have made sufficient revenue reductions to ensure that, on a time-adjusted basis, we do not recover (or earn a return on) $18 million of NIGU expenditure.

This approach provides a relatively smooth set of revenue adjustments over a six-year period, and maintains compliance with Transpower's input methodologies and RCP1 price path determination.

Appendix 3: Application for increase in Major Capex Allowance - where requirements of the Capex IM are satisfied in this document

Capex IM clause reference	Information requirement	Cross reference to location in document
Schedule H Division 1, H2	Identification of the relevant major capex project and its major capex allowance	Appendix 1
Schedule H Division 1, H3 (1)	quantum of proposed amendment to **major capex allowance**;	Section 2.1
Schedule H Division 1, H3 (2)	calculations showing how the quantum of the proposed amendment was calculated;	Section 2.2
Schedule H Division 1, H3 (3)	assumptions made in making those calculations; and	Section 2.3
Schedule H Division 1, H3 (4)	evidence in support of the calculations, including, where relevant- (a) correspondence from manufacturers, suppliers, contractors and other relevant parties; and (b) equipment test results;	Section 2.4
Schedule H Division 1, H3 (5)	proposed **P50**; and	Section 2.5
Schedule H Division 1, H3 (6)	calculations, **key assumptions** and supporting evidence used to determine proposed **P50**, by reference to specified **P50**;	Section 2.6
Schedule H Division 1, H4	description of progress made on the **major capex project**, including details of- (a) planning processes undertaken; (b) resource management consents, other regulatory consents, and property rights and access rights obtained; (c) construction and labour contracts and arrangements made; (d) construction completed; and (e) testing undertaken;	Section 3 Section 3.2 Section 3.3 - 3.5 Section 3.8 Section 3.11 Section 3.12

Schedule H Division 1, H5 (1)	**major capex** incurred to the date of the application;	Section 4.4
Schedule H Division 1, H5 (2)	forecast **major capex**; and	Sections 4.2 – 4.4
Schedule H Division 1, H5 (3)	difference between forecast **major capex** and the **major capex allowance**;	Section 4.4
Schedule H Division 1, H6 (1)	reason for applying, including- (a) description of key factors leading to the application; (b) commentary on the extent to which each key factor is within **Transpower's** control; and (c) commentary on the extent to which each key factor was reasonably foreseeable by **Transpower** before the relevant **major capex proposal** was approved;	Sections 6 - 12
Schedule H Division 1, H6 (2)	description of the implications of the proposed amendment on the relevant **approved major capex project outputs**;	Section 13.1
Schedule H Division 1, H6 (3)	where an application for amendment to the **approved major capex project outputs** is being made concurrently, explanation as to how the proposed amendments relate to each other;	Section 13.1
Schedule H Division 1, H6 (4)	where no application for amendment to the **approved major capex project outputs** is being made concurrently, explanation as to why those **approved major capex project outputs** will remain appropriate were the proposed adjustment made;	N/A
Schedule H Division 1, H6 (5)	statement as to whether the **net electricity market benefit** of the **major capex project** is materially lower at the time of the application than when the relevant **major capex proposal** was approved and if so, current quantum of its **net electricity market benefit**; and	Section 13.2
Schedule H Division 1, H6 (6)	explanation as to why making the proposed amendment would promote the long term benefit of **consumers**;	Section 13.2

Appendix 4: Application for Amendment to Approved Major Capex Project Outputs

A.4.1 Proposed amendments to the approved major capex project outputs

We seek amendment to the approved major capex project outputs for NIGU, as follows:

- Construction of an Air Insulated Substation (AIS) at Pakuranga instead of a Gas Insulated Substation (GIS).

- Instead of installation of 350MVAr of new static reactive plant at the Otahuhu substation, installation of:
    - 200MVAr of new static reactive plant at Otahuhu substation
    - 100MVAr of new static reactive plant at Penrose substation, and
    - 50MVAr of new static reactive plant at Hepburn Road substation.

- Deferral of the acquisition of easements over Auckland Council and Crown reserve land to allow for the future installation of new 220kV underground cables from Brownhill substation to Otahuhu substation.

A.4.2 Explanation as to how each proposed amendment was arrived at

A.4.2.1 Construction of AIS at Pakuranga

We discussed with the Electricity Commission during their consideration of the GUP for the NIGU Project the options of building either an AIS or a GIS at Pakuranga. While either option provided the same outcome in terms of functional capability of the grid, there was uncertainty as to whether necessary resource consents could be obtained for an AIS option. Given the doubt as to whether an AIS could be built due to resource consent requirements, the GUP approved by the Electricity Commission provided for the construction of a GIS (being a more expensive option).

Consistent with our discussions with the Electricity Commission at the time the GUP was approved, as the project progressed we investigated further the option of building an AIS. We were successful in obtaining the necessary resource consents for the construction of an AIS, this being the option approved by the BoI.

Given that the AIS option represented a cheaper way to deliver the same functional outcome in terms of upgrade to the grid, we ultimately decided to build an AIS at Pakuranga.

A.4.2.2 Division of new static reactive plant

As anticipated by the GUP submitted to the Electricity Commission, following approval of the GUP for the NIGU Project we undertook a further study to determine the optimal location of the 350MVAr of new static reactive plant contemplated by the approved GUP. The approved GUP – and hence the approved major capex project outputs for the NIGU Project – provided for the new static reactive plant to be installed entirely at the Otahuhu substation.

Our further studies concluded that installation of 200MVAr at Otahuhu, 100MVAr at Penrose and 50MVAr at our Hepburn Road substations would provide better reactive support. Therefore, to optimise the location of the new static reactive plant, we decided to divide the location of the new plant in this manner.

A.4.2.3 Deferral of acquisition of easements

The Brownhill-Otahuhu cable route is approximately 9.7 kilometres. Property rights to allow construction and continued operation of the proposed 220kV cables remain outstanding for two kilometres of the route as it traverses Auckland Council and Crown reserve lands only. We hold the necessary property rights for the remainder of the route by virtue of statutory rights under the Electricity Act with respect to the location and operation of underground cables in a "Legal Road", and by acquisition and registration of transmission easements over private landholdings.

Transpower lodged its Notice of Requirement (NOR) to designate the BHL-OTA cable route on 28 May 2007. While the cable works were not planned to be built until circa 2021, it was necessary to include the cable works in the NOR as it formed a significant part of the justification for locating the substation at Brownhill Road, rather than a location further south. A designation was subsequently secured for the Otahuhu-Brownhill cable route.

Although it is not necessary to secure property rights over the designated route until closer to the time of construction, section 185 of the Resource Management Act does give landowners an avenue to force purchase of an appropriate property right over land subject to a designation. Accordingly, a decision was made to secure easements over the private landholdings traversed by the designation to compensate those owners for the detrimental impact on property value, and to avoid the likely landowner action under section 185 of the Resource Management Act to force acquisition by Transpower of an easement.

With respect to the public landholdings traversed by the designated route (i.e. Auckland Council reserve land and Crown reserve land), it is not considered cost effective to secure the necessary property rights (i.e .easements) until closer to the time of construction. In the interim, the presence of the designation will ensure that the cable route as it traverses public landholdings will not be compromised by inappropriate development. However, there remains a risk that at any time the Auckland City Council or the Crown will request that Transpower secure and compensate them for an easement(s), and Transpower may be forced to compensate and secure these easements well before construction.

Ultimately, we were satisfied that deferring the acquisition of the easements over the relevant Auckland Council and Crown reserve land was a lower cost option for ultimately obtaining the necessary property rights to allow the installation of the new cables between Brownhill and Otahuhu, and as such would promote the long term benefit of consumers.

A.4.3 Description of the extent to which each proposed amendment reflects a change to the functional capability of the grid

None of the proposed amendments to the approved major capex project outputs reflects a change to the functional capability of the grid.

A.4.4 Description of the extent to which each proposed amendment reflects a change to the quantum of electricity market benefit or cost elements directly related to the supply of electricity transmission services that are likely to be achieved as a result of undertaking the project

None of the proposed amendments to the approved major capex project outputs reflects a material change to the quantum of electricity market benefit related to the supply of electricity transmission services that are likely to be achieved as a result of undertaking the project.

None of the proposed amendments to the approved major capex project outputs reflects an adverse change to the quantum of cost elements directly related to the supply of electricity transmission services that are likely to be achieved as a result of undertaking the project. In all cases, the variations to the approved major capex project outputs we implemented represented lower cost options to achieve the same functional outcome in undertaking the grid upgrade.

A.4.5 Description of any current key assumptions different to those relied upon in applying the investment test in the major capex proposal

There are no key assumptions (in relation to the proposed amended major capex project outputs) that are materially different to those relied up in applying the investment test in the major capex proposal for the NIGU Project.

A.4.6 Description of the outcome of applying the investment test as it was applied in the major capex proposal modified by the proposed amendments

There is no material change in the application of the investment test as it was applied in the major capex proposal modified by the proposed amendments.

A.4.7 Explanation as to why making the proposed amendment would promote the long term benefit of consumers

The proposed changes to the approved major capex project outputs would promote the long term benefit of consumers as:

- The effect of the changes is the delivery of the same improvements in functional capability of the grid, and ultimately the electricity market benefits related to the supply of electricity transmission services likely to be achieved by the NIGU Project, at a lower cost than what we would have incurred had Transpower implemented the particular major capex grid outputs originally envisaged by the grid upgrade plan for NIGU;

- No material sunk costs were incurred in the course of changing the major capex grid outputs, as we were able to update our planning before any material costs were incurred in delivering the particular grid outputs.

Appendix 5: Application for amendment to Approved Major Capex Project Outputs - where requirements of the Capex IM are satisfied in this document

Capex IM clause reference	Information requirement	Cross reference to location in document
Schedule H Division 3, H14	Identification of the relevant major capex project and its major capex allowance	Appendix 1
Schedule H Division 3, H15 (1)	Proposed amendments to the approved major capex project outputs;	Appendix 4
Schedule H Division 3, H15 (2)	Explanation as to how each proposed amendment was arrived at;	Appendix 4
Schedule H Division 3, H15 (3)	Description of the extent to which each proposed amendment reflects a change to the (a) assets to be commissioned; (b) functional capability of the grid (c) quantum of electricity market benefit or cost elements directly related to the supply of electricity transmission services that are likely to be achieved as a result of undertaking the project; (d) in the case of a non-transmission solution, description of the extent to which each proposed amendment reflects a change to any relevant service provided by a third party.	Appendix 4
Schedule H Division 3, H16	Description of progress made on the **major capex project**, including details of- (a) planning processes undertaken; (b) resource management consents, other regulatory consents, and property rights and access rights obtained; (c) construction and labour contracts and arrangements made; (d) construction completed; and (e) testing undertaken;	Section 3 Section 3.2 Section 3.3 - 3.5 Section 3.8 Section 3.11 Section 3.12
Schedule H Division 3, H17 (1)(a)	**major capex** incurred to the date of the application;	Section 4.4
Schedule H Division 3, H17 (1)(b)	forecast remaining **major capex**; and	Sections 4.2 – 4.4

Schedule H Division 3, H18 (1)	reason for applying, including- (a) description of key factors leading to the application; (b) commentary on the extent to which each key factor is within **Transpower's** control; and (c) commentary on the extent to which each key factor was reasonably foreseeable by **Transpower** before the relevant **major capex proposal** was approved;	–Appendix 4
Schedule H Division 3, H18 (2)	Description and, where relevant, quantum of any current key assumptions different to those relied upon in applying the investment test in the **major capex proposal**;	Appendix 4
Schedule H Division 3, H18 (3)	Description of the outcome of applying the **investment test** as it was applied in the **major capex proposal** modified by the proposed amendments and **key assumptions** described in subclause (2), including all relevant calculations and justifications for any exercises of judgment;	
Schedule H Division 3, H18 (4)	Explanation as to why making the proposed amendment would promote the long term benefit of **consumers**;	Appendix 4
Schedule H Division 3, H18 (5)	Where no application for amendment to the **major capex allowance** is being made concurrently, explanation as to why that allowance will remain appropriate were the proposed amendment to the approved **major capex project outputs** made;	N/A

Appendix 6: Supporting Information

The following is a list of the supporting information provided with this application:

1. October 2006 Grid Upgrade Plan documents
   1.1. TP-NI-Supply-Upgrade-Application-process-rev2.pdf
   1.2. A-Diversity-Analysis-for-UNI.pdf
   1.3. B-Treatment-of-the-ARI-PAK-Line.pdf
   1.4. C-Deliver-Risk-Report.pdf
   1.5. D-Technical-Assessment-of-Modified-Options.pdf
   1.6. E-Economic-Analysis-of-Alternatives.pdf
   1.7. F-Costing-Report.pdf
   1.8. G-High-Temperature-Conductor-Report.pdf
   1.9. H1-Timing-of-Auckland-Supply-Upgrade-GUP-Proposal.pdf
   1.10. H2-Pre-Augmentation-EUE-Assessment.pdf
   1.11. I-Duplexing-Report.pdf
   1.12. J-Assumptions-List.pdf
   1.13. K-Economic-Analysis-of-Non-Transmission-Alternatives.pdf
   1.14. L-Transpower-Discount-Rate-for-GIT-Report.pdf
   1.15. M-Assessment-of-the-Value-of-Unserved-Energy.pdf
   1.16. N-Foreign-Direct-Investment-Effects.pdf

2. Electricity Commission design and cost
   2.1. PBA Report on Transpower Oct06 application final.pdf
   2.2. a S0001 05 Technical Review.pdf
   2.3. b Comments on Constrained On Generation Rev1.pdf
   2.4. c Review of Ultimate Thermal Capacity Rev2.pdf
   2.5. d S001 Losses check for 400kV proposal rev1.pdf
   2.6. e ConnellWagner Review Report R1.pdf
   2.7. f PBA 156258A 001 Complete.pdf
   2.8. h PBA 156258A REPT 003 Final.pdf
   2.9. i PBA 156258A REPT 004 final.pdf

3. Electricity Commission and Commerce Commission decision documents
   3.1. EC-Notice-of-Intention-to-Approve-Jan07.pdf
   3.2. EC-Overview-of-Notice-of-Intention-to-Approve-Jan07.pdf
   3.3. EC-Reasons-for-NoI-to-Approve-23Feb07.pdf
   3.4. EC-Final-Decision-5Jul07.pdf
   3.5. EC-Final-Minority-Opinion-5Jul07.pdf
   3.6. EC-Overview-of-Final-Decision-5Jul07.pdf
   3.7. CC-Otahuhu-Substation-Diversity-Project-MCA-Amendment-Final-Decision-12Apr2013.pdf
   3.8. CC-Commerce Act (Transpower Thresholds) Notice 2008
   3.9. CC-Commerce Act (Transpower Input Methodologies) Determination 2012.pdf
   3.10. CC-Commerce Commission decision Individual Price-Quality Path Determination 31 January 2012
   3.11. CC Commerce Commission Capital Expenditure Input Methodology Reasons Paper 2012

4. Original cost estimates
   4.1. NIGUP Option1&2&3 LinesCosts 101006.xls
   4.2. Original 1 NIGUP Option2 400kV CostReport(v3).xls

4.3. Original DesignProcureBuild costs with Fx factor.xls
4.4. Original Property.xls
4.5. Drury Switching Station Costs 11 Oct 06.xls
4.6. GUP 220kV cable cost estimate information (10yr EUR) rev1 060921.xls
4.7. Investigation and Consenting Costs.xls

5. P90 calculation
5.1. NIGU-P90-Cost-Model.xls

6. Grid Investment Test results
6.1. MATLABModel
6.1.1. ASUGITInputTablesBase2042.mat
6.1.2. ASUGITInputTablesBase2042_Revised_130618.mat
6.1.3. GITASU_TPv32.m
6.1.4. GITASUSenstivityRuns_TPV32_REerun130618.m
6.1.5. NNITotalDemandSOO2005MC.mat
6.1.6. Notes on ReRun.txt
6.1.7. NPVMCByScenarioTable.xls
6.1.8. NPVMCRunTable.xls
6.1.9. NPVPercentiles.xls
6.1.10. NPVTerminalValueBreakdown.xls
6.1.11. Sensitivity Table.xls
6.2. Revised Inputs
6.2.1. Cost Inputs_061016_modified.xls
6.2.2. Notes on file.txt
6.2.3. TablesFinal161006.xls
6.2.4. TaqblesFinal161006_updated.xls

7. NIGU actual and forecast end cost
7.1. NIGU-Cash-Flow-31 Aug 2013.xls
7.2. Transfer of Budgets from GUP.xls
7.3. Some NIGUP Budget derivations.xls

8. Technical reports
8.1. Brownhill-Whakamaru line
8.1.1. 400kV Report on Revised Costs IssC 23May06.doc
8.1.2. ADGL 400.06 OTA-WHK 400kV Line Costs ODV Comparison.pdf
8.1.3. ADGL 400.12 Report on Tree Clearances D2.pdf
8.1.4. ADGL 400.16 Indicative Costs for Corridor Options OTA-WKM 400kV line 040803_1056.pdf
8.1.5. ADGL 400.17 Grid Upgrade Plan Final Report May05.pdf
8.1.6. ADGL 400.18 Route Constraints Engineering Review v1.pdf
8.1.7. ADGL 400.34 400kV Report on Revised Costs Final IssC 24May06.pdf
8.1.8. ADGL 400.35 220kV Report on Revised Final Costs Final IssC 24May06.pdf
8.1.9. ADGL 400.39 Guidelines for Design & Construction Practices for Transmission Line Access Tracks v2.pdf
8.1.10. Analysis of SKM Review Estimates.doc
8.1.11. Comparison with SKM Cost Estimates 30May06.xls
8.2. Cables
8.2.1. 220kV Cable Cost Estimate Report April 2003.pdf
8.2.2. AP01106 17 UG Cable Peer Review Report Final.pdf

8.2.3. BHL-PAK Cable Routes 060927.pdf
8.2.4. Brownhills Road final compiled report 12Oct07.pdf

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8.3.1. Transpower internal memo Oct 2008 Property Strategy to achieve project objectives.doc
8.3.2. Crighton Anderson revision to methodology.pdf
8.3.3. Deloitte report.pdf
8.3.4. Chapman Tripp report.pdf
8.3.5. PwC review Dec 2006.pdf
8.3.6. NIGU final report BOI recision.pdf
8.3.7. NIGU final report BOI decision Appendices C to U.pdf
8.3.8. Crighton Anderson easement assessment methodology.pdf

8.4. Substations

8.4.1. Revised 200-400kV plan cost 170906 queries rev2 (MS input).xls
8.4.2. Option 4 – Transition station (ORM) v1.xls
8.4.3. Drury CB&half design – master costs – NPV (20060830version).xls
8.4.4. Drury H design – master costs – NPV (20060830version).xls
8.4.5. Option 4 – OTA enabling works (v1).xls
8.4.6. Option 4A – OTA 220kV (v1).xls
8.4.7. ADG-S-001 400kV AIS v GIS evaluation (Issue 1).pdf
8.4.8. ADG-S-015 NI 400kV Substations – Grid Upgrade Plan Input (Issue 1 V2).pdf
8.4.9. ADG-S-026 NI 400kV Substations – Overview of the Site Selection and Common Design Attributes for the NoR Process_Issue 0_.pdf
8.4.10. ADG-S-027 NI 400kV Transition Station – Overview of the Site Selection and Common Design Attributes for the NoR Process_Issue 0_.pdf
8.4.11. ADG-S_028 Single Line Diagram Design (Issue 1).pdf
8.4.12. ADG-S-030 NI 400kV Substations – Preliminary Layout Design (Issue 1).pdf
8.4.13. ADG-S-031 NI 400kV Substations – 400kV AIS v GIS Recommendation (Issue 1) V2.pdf
8.4.14. ADG-S-032 NI Single Line Diagram Site Selection and Layout Design Summary Report (Draft 1).pdf
8.4.15. ADG-S-039 Peer Review of Substation Costs (Issue 1).pdf
8.4.16. AIS v GIS Options for Whakamaru and Otahuhu PB Power 152257-REPT-001 21-Sep-2005.pdf
8.4.17. BHL Technology Selection Report Nov 2007.pdf
8.4.18. Hybrid Switchgear Options for Whakamaru and Otahuhu PB Power 152257-REPT-002 16 Oct 2005.pdf
8.4.19. Net Present Value estimates for Whakamaru and Otahuhu PB Power 152257-REPT-003 16 Nov 2005.pdf
8.4.20. Peer Review by Mott MacDonald V2 Jun-2006.pdf
8.4.21. Technical Constraints for Substation Site Selection (02-05-04).pdf
8.4.22. Underground Cable Section Transition Station and Substation-final report MWH August 2005.pdf

9. Project management and process documents

9.1. Beca Report 2005.pdf
9.2. Evans & Peck Aug 2005.pdf
9.3. Transpower NIGUP Project Plan February 2009
9.4. NIGUP Programme Management Plan December 2009
9.5. Extracts from Transpower Property Information Manual:

9.5.1.Section 10: Property Valuation.pdf
9.5.2.Section 11: Dealing with Landowners.pdf
9.5.3.Section 12: Freehold Purchase.pdf
9.5.4.Section 13: Easement Process and Construction Access.pdf
9.6. Project Alliance Agreement and SWTC
9.6.1.PAA NIGUP OH Line Part 1.pdf
9.6.2.PAA NIGUP OH Line Part 2.pdf
9.6.3.PAA NIGUP OH Line Part 3.pdf
9.6.4.PAA NIGUP OH Line Part 4.pdf
9.6.5.PAA NIGUP OH Line Part 5.pdf

10. Project close-out reports
10.1. Brownhill-Whakamaru 400kV line.pdf
10.2. Otahuhu Capacitor Banks.pdf
10.3. Hepburn Road and Penrose Capacitor Banks.pdf
10.4. Otahuhu-Whakamaru C Thermal Upgrade.docx
10.5. Brownhill-Pakuranga 220 kV Underground Cables.docm
10.6. Brownhill Road Transition Station.docm
10.7. Otahuhu Substation.docm
10.8. Drury Switching Station.docm
10.9. Whakamaru Substation.docx
10.10. Pakuranga Substation.docx
10.11. Substations General.docm
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11. IQANZ reports
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