WAIKATO AND UPPER NORTH ISLAND VOLTAGE MANAGEMENT

ATTACHMENT D - STAKEHOLDER CONSULTATION SUMMARY

Transpower New Zealand Limited

December 2019

Keeping the energy flowing

TRANSPOWER

Table of Contents

Glossary

Capex IM	Transpower Capital Expenditure Input Methodology Determination, New Zealand Commerce Commission[1].
Code	Electricity Industry Participation Code 2010.
Dynamic reactive device	Dynamic reactive devices can provide variable amounts of reactive power in a few milliseconds. Common examples are static vary compensators (SVCs), static synchronous compensators (STATCOMs), and synchronous condensers. All are capable of rapid dynamic response.
EDGS	Electricity Demand and Generation Scenarios.
Grid Reliability Standards	The grid reliability standards (GRS) are a set of standards against which the reliability performance of the existing grid (or future developments to it) can be assessed as defined in the Code (schedule 12.2).
GSC	Grid support contract, used for non-transmission solutions.
GXP	Grid exit point.
Immediate investment horizon	The period from 2023 until the end of 2024 which is the subject of our Major Capex Project application with the Commerce Commission.
Investment Test	The Capex Input Methodology defines the ‘Investment Test’ as the detailed assessment required for Major Capex Projects.
Long-list consultation	Transpower’s consultation document entitled Waikato and Upper North Island Voltage Management Long List Consultation July 2016.
LRMC	Long-run marginal cost.
MBIE	Ministry of Business, Innovation and Employment.
MWh	Megawatt hour of electrical energy.
N-1	A security standard that ensures with all facilities in service Transpower’s transmission system remains in a satisfactory state following a single fault (e.g. a circuit outage).
N-G-1	A security standard that ensures with a generator out of service Transpower’s transmission system remains in a satisfactory state following a single contingent event (e.g. a circuit outage). The ‘G’ in N-G-1 is also a proxy for slightly less severe transmission equipment contingencies.
Rankine	A type of coal/gas generator owned and operated by Genesis Energy at Huntly.
RFP	Request for proposal.
STATCOM	A static synchronous compensator is a device that provides fast reactive power compensation.
SVC	A static var compensator is a device that provides fast reactive power compensation.
TOV	Transient over-voltage.

1 See http://www.comcom.govt.nz/regulated-industries/electricity/electricity-transmission/

TPM	Transmission Pricing Methodology, defined in Schedule 12.4 of the Code.
Transpower	Transpower New Zealand Limited, owner and operator of New Zealand's high-voltage electricity network (the national grid).
UNIDRS	Upper North Island Dynamic Reactive Support project.
Voltage sensitive load	Electricity load that is sensitive to fluctuations in the supplied voltage. Such loads include inductive motors (e.g. industrial motors) that will react following a fault impacting system voltage recovery.
WUNI	Waikato and Upper North Island.
WUNIVM	Waikato and Upper North Island Voltage Management.

1 Introduction

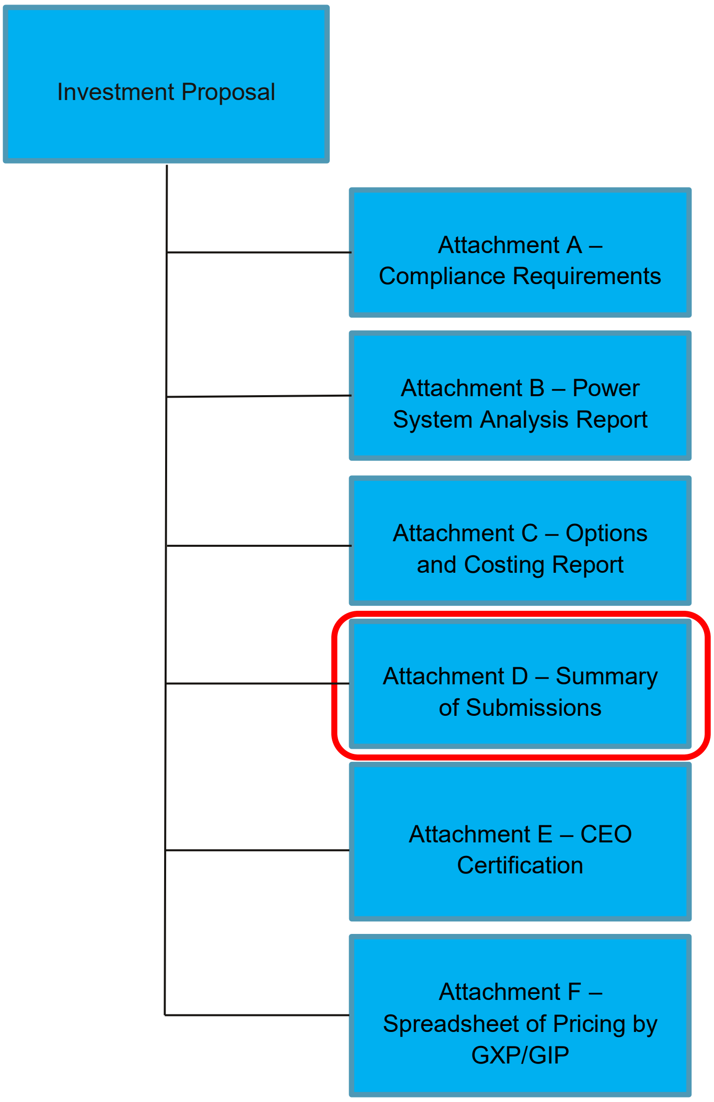
1.1 Purpose

The purpose of this document is to outline stakeholder consultation and feedback to Transpower on the Waikato and Upper North Island Voltage Management (WUNIVM) investigation and Transpower's response to that feedback.

1.2 Document structure

This document forms part of the WUNIVM Major Capex Proposal application.

It is one of the supporting attachments for our main report ('Waikato and Upper North Island Voltage Management Major Capex Proposal') and should be read in conjunction with our main proposal.



1.3 Stakeholder engagement to date

Date	Activity
November 2015	Thermal decommissioning analysis
July 2016	Long-list consultation and invitation for information on non-transmission solutions
July 2017	Integrated transmission plan
May 2018	Investigation update
June 2019	Consultation on short-list of investment options
October 2019	Second request for information on non-transmission solutions

Details of the long-list and short-list consultations can be found in the following sections, as originally published following these consultations. A summary of other stakeholder engagement activities is in the main proposal.

2 Long-list stakeholder consultation (July 2016): Summary of submissions with Transpower responses

This section summarises submissions received on Transpower's *Waikato and upper North Island voltage management long-list consultation* of July 2016[2]. We have endeavoured to summarise submitter's key points briefly. Please refer to their submissions for further detail, and to Appendix A.1 for how we addressed issues raised.

Submissions were received from:

- **Auckland Council**, the submission being from the Council's Auckland Plan, Strategy and Research Department rather than the Auckland Council itself
- Contact Energy Limited (**Contact**), an electricity generator and retailer
- **Counties Power**, an electricity distribution company in the south-west Auckland region
- Electra Generation Limited (**EGL**)
- **Electrix**, a provider of engineering, construction and maintenance services
- Genesis Energy (**Genesis**), an electricity generator and retailer
- Mercury Energy (**Mercury**), an electricity generator and retailer
- Meridian Energy (**Meridian**), an electricity generator and retailer
- The Major Electricity Users' Group (**MEUG**), a trade association representing major electricity users

[2] The consultation paper, the non-confidential submissions and this document are available at www.transpower.co.nz/waikato-and-upper-north-island-voltage-management-investigation.

- Mitsubishi New Zealand (**MNZ**), an electric power equipment supplier
- Northpower Limited (**Northpower**) in its role as an electricity distributor in the upper North Island
- **Pacific Aluminium**, the business unit of Rio Tinto responsible, inter alia, for managing its majority shareholding of the New Zealand Aluminium Smelter (NZAS) at Tiwai Point
- Siemens Limited (**Siemens**), a supplier of transmission utility solution products, designs and services
- Top Energy Group (**Top Energy**) which includes the Top Energy electricity distribution business and Ngawha Generation Limited, which owns the Ngawha Power Station
- **Trustpower,** an electricity generator and retailer (which also supplies gas and telecommunications services). The content of Trustpower's submission is confidential to Transpower so is not referred to below.
- Vector Ltd (**Vector**), an electricity (and gas) distribution company in the Auckland region
- WEL Networks (**WEL**), an electricity distribution company in the Waikato.

This section includes submitters' comments against the 14 specific questions asked in the consultation report, plus any general comments of relevance to specific questions. Except for questions 2, 3 and 4, the sub-section number corresponds to the question number. We provide our response to each issue raised.

2.1 Need and project scope

Q1	Do you agree with our assessment of need and project scope? Are there any other issues or considerations relating to the need or scope that we should incorporate into this project?

Most submitters either agreed to the need and scope or did not comment.

There were many comments on the TPM and DGPP, which we cover in Section 2.15 and 2.16 respectively.

Other comments were:

2.1.1 Need for wider scope

The Auckland Council's main concerns are around the cost of any investment to the homeowners and businesses in the Auckland region and its effect on Auckland's competitiveness, as well as the investment's impact on the Council's policies and strategies around growth and climate change. The Council believes that the scope should be widened to include:

- the national climate change targets

- the wider picture of Auckland's future
- costs of power distribution as well as transmission.

Transpower response: *To obtain approval of an investment proposal from our regulator the Commerce Commission, Transpower must meet the requirements of the Capex IM for Major Capex Proposals (MCPs). This requires that the proposed investment has (amongst other things) a positive or maximum expected net electricity market benefit. That is, the test is a market benefit test rather than consumer benefit or national benefit. We therefore cannot consider benefits other than electricity market benefits, or to parties other than electricity market participants, which includes electricity consumers.*

We can consider distribution costs and will seek to consult with distribution companies regarding how our options materially interact with their options and costs.

2.1.2 Definition of the N-1 contingency

Contact notes that the N-1 scenario identifies a Pakuranga-Whakamaru circuit as the critical contingency, and asks whether it would be more prudent to consider the more onerous Huntly unit 5 as the critical contingency, which would result in a lower N-1 limit.

Transpower response: *In our investigations we consider the most stringent contingency, whether it is transmission or generation. Our studies show that the Pakuranga-Whakamaru circuit and the Huntly unit 5 contingencies have similar impact. If this changes as we develop and improve our analysis, then we shall consider the more stringent contingency.*

Our choice of reliability level will also be subject to economic analysis as part of this investigation, considering the likelihood, consequence and cost of mitigation of a contingency.

2.2 Reactive power devices, batteries and transmission

On questions 2, 3 and 4 we received closely related responses, so for simplicity, readability and to avoid repetition we have sorted the submissions and our responses to these three questions by topic.

Q2	Do you agree with our draft long-list of components? If not, what components should we include or remove?

Most submitters agreed with, or did not comment on, our draft long-list of components.

Q3	This document serves as an invitation to provide information on non-transmission solutions. Any submission on this aspect should provide as much detail on the non-transmission solution as possible. Do you have any suggestions or proposals for non-transmission solutions to meet the need? If so, please provide the information requested (in Section 5.5 [of the consultation paper]) so that we can apply a high-level assessment against our short-listing criteria.

Many parties submitted information on non-transmission solutions.

Q4	Do you have any suggestions for enhancing Transpower's grid support contract (GSC) product design? If so, please provide your reasons, based on the rationale provided in our GSC design features document at www.transpower.co.nz/grid-support-contracts

Most submitters offered no suggestions for enhancing Transpower's GSC product design, but we received some useful feedback described below.

We have sorted the response to these three questions into three topics:

- Reactive power devices, batteries and transmission – this Section 2.2
- Long-term grid support contracts (GSCs) – Section 2.3
- Other solutions and product design issues – Section 2.4

2.2.1 Static capacitor banks

Contact questions why static capacitor banks are being considered as a solution, as unless these can be switched in pre-contingency they are not considered in the current real-time voltage stability assessment. Contact encourages Transpower to consider dynamic reactive assets as the most practical transmission solution, noting that an increase in dynamic assets would also allow more of the existing capacitors to be switched in pre-contingency to further improve the voltage stability limit.

Transpower response: *Static capacitor banks are one of the cheaper means of voltage support. We will be considering installing static capacitor banks to support low voltage buses to raise the overall voltage profile across the North Island transmission system. Raising the voltage profile will help minimising congestion of real-power flows and transmission losses.*

As load grows more capacitors are required to support voltage pre-fault (pre-contingency). In general capacitors are switched into service as load starts to peak. It is generally more economic to use capacitor banks rather than dynamic devices to provide pre-fault (pre-contingency) voltage support, allowing the dynamic devices the greatest headroom for post - fault voltage support.

We will be considering the combination of static and dynamic reactive assets that provide the greatest net benefit.

2.2.2 Synchronous condensers

Auckland Council supports conversion of local generation plant to synchronous condensers based on its price and location, noting that at the present time there is no cost-effective option for reliable power generation of the scale required in the upper North Island.

Genesis states that the costs and practicalities of converting existing Rankine generation units into synchronous condensers (post-2022) have not been studied recently, but offers to explore this option with Transpower.

Mercury has supplied confidential information on the high-level feasibility and costs associated with converting its Southdown generators to synchronous condensers as a non-transmission solution. Mercury believe that Southdown represents a reliable low cost dynamic voltage support option to de-risk the early closure of the Rankine units: “Southdown will complement investment in static voltage support and act as a bridge to future dynamic voltage support projects”.

Electrix states that the best solution would be the conversion of decommissioned thermal power plant to synchronous condensers. This could either be contracted as a service through a GSC or be purchased and operated by Transpower. Electrix notes several further benefits of a synchronous condenser over capacitors or static compensation, detailing these in its submission. Electrix advises that the Omexom/Electrix team could offer full service conversion of existing plants to synchronous condensers without the need for the original equipment manufacturer.

Transpower response: *Conversion of local generation plant to synchronous condensers could be an attractive option. We will be considering the contribution of such devices to meeting the need, and their economics, and may in due course issue an RFP for a grid support contract (GSC) for such services.*

2.2.3 SVCs and STATCOMs

Siemens provided information on its lead time for an SVC or STATCOM solution.

Transpower response: *We thank Siemens for the information.*

2.2.4 Hybrid STATCOM/battery

Siemens notes that hybrid STATCOM/battery is an evolving technology and has the ability to not only provide reactive but also active power and “artificial inertia” to compensate for network voltage and frequency excursions. Siemens notes also that lack of inertia is a growing problem in transmission networks with the progressive retirement of base-load thermal generation. Siemens provided information on the technical characteristics of its energy storage solutions.

Transpower response: *We thank Siemens for the information.*

2.2.5 Batteries

Auckland Council recommends that a combined renewable and grid storage battery option should be included in the options considered to replace power generation, reduce the need for new transmission and distribution lines to green-field developments, and complement future solar photo-voltaic (PV) generation installations.

Contact supports the inclusion of “large – multiple tens of MW – batteries, or battery banks or aggregations of that size” as a possible non-transmission solution, as grid scale storage is a maturing technology that is quickly developing. Contact would like to see consideration given to the additional grid and market benefits of emerging technologies beyond the need for just voltage support i.e. additional functionality of batteries to provide peaking capacity, instantaneous reserve, frequency keeping, and black start services. Contact offers to work with a reputable battery storage provider to deliver a reliable storage solution, acting as an aggregator of the multiple value streams that flow from the energy storage installation.

Contact, Counties Power and MNZ note that that grid-scale storage can be viewed by Transpower as a potential transmission or non-transmission asset, and that the latter could be centralised or de-centralised and aggregated. MNZ adds that experience overseas shows that grid-scale storage can find value ‘niches’ across the electric power supply chain; generation, transmission, distribution and at the consumer level among commercial and industrial customers.

MNZ describes how a feature of its battery storage system is its capability to fulfil more than one mission, and it is this flexibility, as well as performance, that can bring added value, to the selection of grid-scale storage by Transpower, compared to alternative solutions. MNZ notes how, compared to turbines, grid-storage is ‘always on’, ‘always synchronised’ and is dispatch-able in any amount to the nameplate capacity in under a second. MNZ provided information on the technical characteristics of its energy storage solutions.

Counties Power notes how batteries could address the need by reducing demand and providing reactive support when required.

Electrix is however of the opinion that utility-scale battery storage is a strange solution to solve reactive power issues and transient dynamic voltages sags, and is much more relevant for frequency keeping.

Transpower response: *We agree that battery storage is a promising technology for many grid services, including voltage support. This investigation will consider batteries as a potential component of the solution, and the breadth of their potential benefit.*

A battery could be owned by Transpower or contracted through a GSC as a service, either from a single source or an aggregator.

Contact submitted that the GSC design should be reviewed to consider the unique characteristics of new energy storage technologies, noting also that their treatment in the Code and the Capex IM should be reviewed too. Contact submits also that Transpower should consider the extent to which the Capex IM should create a separate non-transmission solution cost allowance for energy storage.

Transpower response:	*The GSC design allows for contracting with battery service providers, whether the battery solution is treated as an embedded generator or a voltage support service or a market generator. However, we accept that our GSC design document could be more explicit on how batteries will be treated: we will update the document in due course to make this clearer.* *We will consider the Capex IM issue that Contact has raised.*

2.2.6 Reducing impedance on the Stratford to Huntly circuits

Contact asks whether the use of series capacitors to reduce the impedance on the Stratford to Huntly circuits would be an option.

Transpower response:	*Using series capacitors to reduce the impedance on the Stratford to Huntly circuits would not materially help resolve the voltage stability issues that are the focus of this investigation, so we have not considered this option in this analysis. Studies have indicated that following the decommissioning of the Rankine units any replacement generation south of Huntly, especially in the Taranaki region, could cause either of the Stratford to Huntly circuits to overload when the other circuit is out. We acknowledge this thermal issue and will commission a separate work stream outside of this investigation to address it.*

2.3 Long-term grid support contracts (GSCs)

2.3.1 GSCs for transmission avoidance

Contact, while generally agreeing with the approach taken with the design of the GSC, considers that we should include GSCs as longer-term alternatives to transmission investment. Contact thinks that the term of the GSCs also needs to be longer, as if Transpower were to invest in assets (e.g. capacitor banks) it would earn a regulated rate of return over the life of the asset, while participants making similar investments would only have a certain rate or return over the (relatively short) term of the GSC.

Contact notes that the assumption that GSC service costs increase with demand response frequency and duration (GSC design feature 6) may be incorrect, as with developments and deployments of storage technologies, costs are likely to fall and reliability increase. Contact suggests that GSCs of a longer term than the suggested 1-3 years should be considered in the context of transmission investment alternatives to ensure the most efficient outcomes for end consumers. (Transpower notes that the design feature that Contact is referring to applies only to GSCs for DSP and market generation, not for voltage support GSCs.)

Transpower response: *We will consider revising our GSC design to include long-term GSCs for market generation, including for transmission avoidance, if this emerges as an economic solution to this investigation (or in response to any relevant regulatory changes).*

With regards to the recovery of asset costs, the point is correct but not complete. If, for example, capacitor banks, as a temporary measure for X years, were the most economic solution, then whether they were owned by Transpower or contracted by Transpower through GSCs, the value and cost would be equivalent, albeit recovered differently.

2.3.2 Market generation

Submissions relating primarily to future market provision of market generation are covered in question 11 on generation scenarios (Section 2.11).

Genesis notes that while a GSC for market generation is feasible the principles appear to limit the extent to which such a contract would be commercially viable by itself.

Genesis provides high level information around the option to retain up to two Rankine generation units in service past publicly indicated decommissioning dates.

Contact notes that only offering GSCs to generators who modify their plans to meet Transpower requirements may not deliver efficient market outcomes.

Top Energy submits that one component for addressing the need might be to bring forward the Ngawha commissioning dates. They are interested in discussing this option with us. See comments in Section 2.11.1 also.

See also Northpower's response in Section 5.11 on generation scenarios.

Transpower response: *We will consider revising our GSC design to include long-term GSCs for market generation, including for transmission avoidance, if this emerges as an economic solution to this investigation (or in response to any relevant regulatory changes).*

We will discuss with Top Energy their plans and possibilities for the Ngawha generation plants.

2.3.3 Reduction of peak load

Auckland Council recommends that one of the long list options should be a focus on the reduction of peak load, recognising that this is a wider issue dependent on a number of other areas not related to the power transmission system, from increased efficiency of appliances and buildings, to controls or demand shifting of local loads.

Transpower response: *Transpower does not offer GSCs for permanent peak load reduction, as to do so would put us in the position of a 'megawatt' provider of last resort. We will offer grid support contracts for temporary peak load reduction, for the purposes of managing build risk, where they are practical, reliable and economic.*

We will consider revising our GSC design if permanent peak load reduction emerges as an economic solution.

2.3.4 More embedded generation

EGL believes that with the right support it could build more distributed peaking plants and would like to engage on opportunities to provide more embedded generation in Auckland.

Transpower response: *We thank EGL for the information, which is very relevant if pre-contingent net load reduction becomes part of the solution to this investigation.*

2.4 Other solutions and product design issues

2.4.1 Market constraints

Contact supports the use of voltage support GSCs as they provide pricing certainty for UNI consumers, rather than the uncertainty of operationally managing the issue with market constraints until a longer-term solution(s) can be implemented.

Meridian considers that the current voltage stability constraints have the potential to distort the wholesale electricity market, and priority should be given to components that can be implemented early to reduce the reliance on such constraints.

Mercury expresses concern over the use of voltage stability limits, due to their potential impacts on market power, dispatch, price and consequent distortion of New Zealand's energy-only wholesale market. Mercury believes that reliance on such voltage stability limits over other long-list components would restrict the level of power transfer into UNI and increase the reliance of UNI consumers on local thermal generation.

Transpower response: *Security constraints are a necessary part of the dispatch process to ensure that system security is maintained. Security constraints reflect, within modelling limitations, the physical reality of the system.*

Security constraints will clearly not meet the need, which will need to be met by physical assets, whether provided by the market, Transpower-owned, or contracted by Transpower as non-transmission solutions. We cannot at this stage be sure that the most economic physical solution will remove the need for security constraints related to voltage management in the Waikato and UNI. The 'use of dynamic analysis to determine voltage stability limits operationally', included as a component in our consultation paper, may enable us to operate the system less conservatively through *better information, potentially providing in effect similar benefits as dynamic line rating could for thermal issues.*

2.4.2 Distribution company developments

WEL are currently developing strategies for its network that may assist WUNI voltage management within the timeframes indicated in the consultation paper. WEL aims to keep Transpower informed of its proposed developments as they are finalised, and asks Transpower to advise them when proposals would need to be submitted for consideration.

Transpower response: *We thank WEL for this information and look forward to developments. We will advise all submitters of our timetable for issuing any RFPs. Our current high-level project schedule is available on our website.*

2.4.3 Medium term load forecast

Contact notes that inaccuracies in the System Operator's load forecast push out the call time for demand response therefore increasing the cost of the service, which supports an upgrade of the System Operator's current tool to reduce cost and increase the reliability of the service.

Transpower response: *If pre-contingent load reduction becomes part of the solution to this investigation, we will consider the costs and benefits of improvements to the System Operator's medium- or short-term load forecast to make demand response more effective.*

2.4.4 Payment for voltage support services

Contact suggest that we review the basis on which providers of voltage support services are rewarded for the value that they deliver in providing such services, to ensure efficient market outcomes and consistency with other ancillary services.

Transpower response: *Under the GSC design, voltage support services would be contemplated if they form part of the most economic means of meeting the need (which would test their value), and payment for voltage support services would be negotiated with the provider following an RFP process.*

Voltage support ancillary services have a payment arrangement embodied in the Code. However, it is our intention to use GSCs rather than ancillary service contracts for long-term investment alternatives such as we are considering in this investigation.

2.4.5 Level of aggregation

GSC design feature 32 states that "Transpower may define in its RFP a minimum block size in order to keep the number of blocks manageable by the System Operator": Contact suggests that actively seeking to limit the number of GSC providers needs to be weighed against the development of a competitive market for GSC services, to help ensure the best long-term benefits for consumers.

Transpower response:	*Transpower has implemented a demand-response management system for pre-contingent demand response with a very low minimum entry size specifically to develop a competitive market for GSC services. However, for some other GSC services, such as post-contingent response, simplicity of operation may be paramount.*

2.4.6 GSCs for intermittent generation

GSC design feature 49 describes how market generation GSCs will not be offered to intermittent generators with limited or no fuel storage or with limited fuel storage. EGL suggest that offers to intermittent generation should be extended to include distributed generation.

Transpower response:	*Transpower includes distributed generation in its GSC product design, but in the 'Demand-side participation including non-market generation' rather than the 'Market generation' form of GSCs.*

2.5 Criteria for short-listing

Q5	Do you agree with our criteria for short-listing? If not, what criteria should we modify, include or remove, and why?

Several submitters commented on the need for flexibility, discussed in Section 2.5.1. Otherwise, most submitters agreed to or did not comment on our criteria for short-listing, but some submissions were made, described in Sections 2.5.2 onwards.

2.5.1 Flexibility

Mercury notes the degree of uncertainty, in particular the possibility of an early exit by the Tiwai aluminium smelter triggering an early retirement of the Rankine units, and hence submits that Transpower develop voltage support options that are flexible and robust to this. Mercury adds that, given the length of the analysis period and uncertainty around key drivers of voltage support needs, this programme should consist of a variety of staged investments and options capable of responding with agility to short/medium term changes in the need. To achieve this, Mercury submits, Transpower must give strong consideration to the real option values conferred by the ability to undertake phased investment decisions.

MEUG expresses the view that "there are so many moving or about to be modified elements".

MNZ notes that the investigation faces uncertainty over new thermal generation in the region so that equipment that can operate in multiple modes has added value.

Vector recommends include an "optionality" criterion to account for the inherent uncertainty of prevailing demand scenarios and the impact technology change may have, and assist with Transpower having more flexibility when evaluating the long-list of options.

Auckland Council suggests that we should introduce a criterion for future proofing, to favour options that enable the system (comprising both the national and local electricity supply grid) to respond to future changes, e.g. in increased variability for solar PV penetration.

Transpower response: *We agree that, for this investigation in particular, flexibility is critical: as MEUG put it succinctly, 'there are so many moving or about to be modified elements'. We will add to the criteria under flexibility 'Is the solution robust and adaptable to the range of foreseeable outcomes'. We will also ensure that one of our scenarios will include the early retirement of Tiwai with consequent earlier retirement of the Rankins units.*

To clarify, the criteria presented in the long list consultation are used to reduce the long list of components to a short list. Transpower then selects the preferred solution from the short list using the Investment Test defined in the Capex IM.

We consider option values and the possibilities of staged or 'triggered' investments in all our investment investigations, but will give particular focus to them for this one.

2.5.2 Resilience

Auckland Council suggests that a criterion should be increased resilience of the system particularly in upper North Island and Auckland area, given that most power is imported into the region, options that enable more local generation (including solar PV and wind) will increase energy resilience.

Transpower response: *This investigation is focused on addressing voltage management issues rather than all issues, but within that scope we will be considering resilience. We consider resilience as a component of reliability. Levels of resilience need to be justified economically, and our primary approach to this is through considering high impact low probability events (HILPs).*

2.5.3 Experience with technology

Auckland Council notes that one of the criteria is technical feasibility and one consideration under this criterion is whether Transpower has any previous experience with the technology. The Council submits that this position will limit the options considered and does not enable the use or investigation of new technologies, and recommends that this criterion is broadened to include solutions have been successfully applied in other countries.

Contact acknowledges the risks of investing in emergent technologies but believes that these need to be weighed against delivering the best long-term benefits for consumers.

Transpower response: *We include in our short-listing criteria two sub-criteria; 'is this proven technology (i.e. used internationally…)?'; and 'does Transpower have experience with the technology?'. These we take as guides: that is, both are desirable, but neither is essential.*

Within our GSC design, we have the specific feature (number 27) that Transpower may accept an emergent technology that has not yet demonstrated appropriate reliability as part of a solution mix so long as overall solution reliability can be achieved.

2.5.4 Net benefit

Contact would like to see the inclusion of market impact and efficiencies for the end consumer considered in the criteria. Contact does not agree that solely using the market to manage the issue in the interim as a solution, as a net pivotal situation is created within the highest demand region in the country and "constraining on" of generation may create additional costs for all consumers rather than just consumers in the upper North Island.

Mercury considers that the screening criteria should not just consider system security benefits but also the high-level changes in fuel costs to New Zealand resulting from the deployment of a particular solution, as per the requirements of the "investment test" under the Capex IM. Mercury considers that potentially adverse or perverse wholesale market impacts should also be considered at a high level, at least qualitatively. Mercury recognises that these impacts are not straightforward to contemplate but notes that the Investment Test criteria explicitly include "competition effects (in the electricity market)".

Transpower response: *The short-listing criteria are intended to act as a coarse filter to remove long list components that do not warrant further consideration. Options that pass this process are assessed in more detail using the Investment Test, which includes market impact modelling.*

As Mercury appreciates, market impacts are not straight-forward to calculate so the uncertainty in high-level estimates of them is significant. Inclusion of market benefits as a short-listing criterion would risk filtering out options prematurely. While this approach could reduce the number of options on the short list, Transpower considers it a less robust than the one proposed in the consultation.

2.5.5 Timeframes

Northpower submits that there is a significant risk that some alternatives will be ruled out due to timeframes, stating that Transpower should identify needs sufficiently in advance so that all viable alternatives to transmission have realistic chances of being developed: otherwise the transmission options will always be the only viable options due to short timeframes.

Transpower response:	*The need for this investigation was driven primarily by the 'thermal decommisionings' that have occurred and are planned to occur. Given this, Transpower believes that it has acted expeditiously to identify and publish the need, and through consultations such as this to seek information on viable alternatives to transmission.* *We consider that one of the key advantages of non-transmission solutions is that they can often be implemented much faster than transmission solutions.* *We encourage any parties that have proposals that cannot be implemented in the timeframes required to engage with us. While the need for this investigation is triggered by thermal decommissionings, load growth in the upper North Island increases the need for local generation and/or transmission capacity and voltage support. Investments that cannot be implemented in time for this project could form part of future projects.*

2.6 Demand growth assumptions

Q6	Do you think that the demand growth assumptions are appropriate for this project? If not, how could we improve them?

This section covered the base demand prior to any potential impact from the proposed removal of the DGPP and the RCPD charge from the TPM, covered in the next section.

Most submitters agree that our demand growth assumptions are appropriate for this project, or made no comment, with the following specific suggestions and observations:

2.6.1 Qualitative concerns over the forecasts

Auckland Council predicts that Auckland, with a high predicted population growth and potential for greater number of electric vehicles, could account for much of expected growth in demand in the upper North Island region.

Genesis notes that the demand growth is on the high side based on what has been observed over the last few years, but considers it reasonable to assume that UNI demand growth will be higher than national demand.

EGL observes that the expected demand growth appears higher than the actual as of August 2016, albeit that this was a warm winter with hydro-dominated pricing. MEUG notes the expected winter peak demand growth rates are relatively high (1.2% per annum in UNI for next 5 years and 1.6% per annum for Waikato) compared to the last few years, and that it will be able to take a more considered view after further consideration of the EDGS.

EGL thinks also that the contribution of solar to the UNI peaks is unlikely due to the low winter production, and that there are no incentives for domestic batteries to transfer consumption to off peak due to their round-trip efficiency. EGL considers at the moment that electric car uptake is certain but that its impact on the peak demand will be dependent on consumer behaviour.

Counties Power notes that the uncontrolled demand-side participation option (such as electric vehicles) should only be applicable to selected load scenarios with additional transport electrification demand.

MEUG believes that there is an open question if there has been a structural change since the global financial crisis in the drivers of electricity demand. MEUG may ask MBIE to refresh the EDGS within the next two years to take into consideration another one of two years' actual data to check if the relative influence of drivers affecting peak demand have changed. MEUG believes that an updated EDGS within the next two years would give more confidence to the economics and justification of any major capex proposal resulting from this investigation.

MEUG adds that after the Commerce Commission decisions on the review of distributors' Input Methodologies are published there will be more certainty for parties (i.e. retailers and distributors), which could invest in non-transmission products and would then be able to advise Transpower of their investment plans and therefore the impact on net demand forecasts. MEUG considers that, prior to the publication of the new Input Methodologies, prospective suppliers of non-transmission components may not have invested time and resources in considering business opportunities in any detail.

Northpower raised the issue that (apart from the DGPP and the RCPD charge covered in the next section) if the proposed TPM is implemented, the "huge increases in transmission costs for industries and other businesses in the UNI would be expected to result in some firms shutting down local plants in the UNI. This would have a direct effect on previous forecasts, plus indirect effects if higher unemployment in the region pushes NZ closer to recession". Northpower therefore proposes a "lower peak load" scenario to the growth assumptions in the paper (see also Northpower's comment to question 7 below, Section 2.7.2).

Transpower response: *MBIE asked NZIER to review Transpower's demand forecast methodology following feedback on the draft EDGS in 2015. As a result of that review, we made some methodological changes that have resulted in a reduction in the level of year one of the forecast but have had little impact on growth rates.*

Transpower's forecasts are region-specific resulting in UNI and Waikato forecasts that grow more quickly than national forecasts. In the UNI region, the higher growth-rate is driven primarily by expected population and GDP growth. The Waikato region's historical growth-rate has been relatively high, which results in a high load growth forecast. Transpower's national forecast growth-rates are consistent with the growth-rates in the 'Mixed Renewables' scenario in the EDGS.

Submissions highlight the difficulty in producing demand forecasts by presenting arguments for both higher and lower forecasts than might be expected. We are developing our forecasts further to consider the impact of solar PV and battery storage, which could result in lower peak forecasts for some market development scenarios. We will continue to monitor changes to the TPM and consider how they might increase peak forecasts.

There is uncertainty in any forecast so Transpower will undertake sensitivity testing to low and high demand growth as required by the Capex IM.

2.6.2 Forecast for Kaikohe

Top Energy believes that the forecast for the Kaikohe GXP is understated, as it expects a further 5 MW of demand on the Karikari Peninsula over the next three years, and it is promoting an Energy Park at Ngawha seeking significant energy users, which is likely to add further demand of 15 to 20 MW.

Transpower response: *Transpower thanks Top Energy for this information and will be in contact to obtain further details.*

2.6.3 Greater granularity in our assumptions

Counties Power would like the underlying assumptions of our demand forecasts to be made clearer, including those relating to traditional demand, electric vehicles and batteries. Counties Power believes information on typical daily load profiles and load duration curves would be relevant too, as there could be material profile changes under non-traditional growth models such as electrification of transport or the increased uptake of residential energy storage (with or without onsite generation).

Transpower response: *We thank Counties Power for its feedback. A paper outlining Transpower's peak demand forecast methodology has recently been updated and is available on Transpower's website[3].*

[3] www.transpower.co.nz/sites/default/files/plain-page/attachments/Transpower%20National-Regional%20Peak%20Demand%20Forecasts%20Jul-2016%20Information%20Document.pdf

2.7 Removal of DGPP and RCPD charges

Q7	Do you think that, if the proposed removal of the DGPP and the RCPD charge from the TPM occur, net peak demand in the upper North Island will be affected? If so, by how much?

2.7.1 Qualitative comments

Contact says it is possible that net peak demand will increase following the proposed TPM and DGGP changes, but that it is also possible that network companies will continue to control demand to reduce distribution network congestion. Contact says that if net peak demand did increase post TPM and this increase led to transmission constraints (and therefore higher nodal prices in affected regions), it is likely that retailers will contract with distribution companies to manage peak demand, or incentivize customers directly to reduce demand with tariff structures or through the use of storage or load control devices.

Counties Power expects that there would be less incentive to smooth the load profile.

EGL says that it would not have run its generation plant over the 2016 winter if ACOT payments were removed. This is because electricity prices did not reflect peak demand. EGL are certain net peak demand will increase as a result of the proposed changes but cannot comment by how much. EGL observes that some distributors are reporting no ACOT payment and at the same time reporting connected distributed generation: the industry information needs to be improved to better understand the issue.

Genesis does not have a strong view on how the UNI peak demand will be affected.

Meridian considers it premature to assume any impact on net peak demand in the Upper North Island arising from these proposals, given uncertainty over the final form of the proposals, and that Transpower has mechanisms including LRMC charging, grid support contractors and payment of ACOT charges.

Mercury appreciates that net peak demand in the upper North Island could be affected by changes to the TPM and DGPP, but does not have a firm view on the extent to which this would occur.

Vector notes that there are only a few generators operating on the Vector network so the impact of the changes to the DGPP will not have an immediate effect, and that removing the DGPP incentive only further discourages new generation to embed in the region. Vector notes also that the changes to RCPD will remove the incentive for load control and so is likely to have a step change effect on peak-demand in the UNI.

Transpower response:	*Transpower thanks participants for their feedback. This is an area of considerable uncertainty – in terms of any step jump in peak demand, the elasticity of peak demand to price, and what price-signals might be under the future TPM.*

Transpower will continue to monitor developments and consider how this uncertainty can be captured in our investigation.

2.7.2 Quantitative assessments

Northpower expects (in the absence of other factors such as business closures through an increase in TPM charges to the UNI), a 10% increase in peak demand on the Northpower network if RCPD charges were removed and another 5% if DGPP disappeared. Northpower recommends that Transpower specifically requests that data from each distributor, each direct- connect customer and owners of distributed generators, as this aspect is too important to leave to speculation. Northpower therefore proposes a "higher peak load" scenario" to the growth assumptions in the paper (see also Northpower's comment to question6 above, in Section 2.6.1).

Top Energy submits that, if the Authority's proposed changes to the TPM and DGPP are progressed, incentives to manage load at peak times will be much reduced. Removing the RCPD price signal would mean that Top Energy would have much less incentive to invest in or operate ripple control at peak times. Top Energy submits that the load shed through use of ripple control is approximately 12%-15% of its current peak demand, and that it may be prudent for Transpower to increase the demand forecasts in anticipation of the proposed TPM and DGPP changes leading to increases in peak demand.

Transpower response: *Transpower thanks Northpower and Top Energy for their feedback.*

While preparing our response to the EA's DGPP and RCPD proposal, Transpower obtained more granular distributed generation data from the Reconciliation Manager. We intend to use this data to capture better the impact of embedded generation in our peak demand forecasts

Transpower will engage with distribution companies and direct connects in the area to obtain information about the level of load control. However, we have found in the past that reliable data on the level of load controlled at peak times is difficult to come by.

We will undertake sensitivity analysis on high and low demand growth as required in the Capex IM.

2.8 Motor load information

Q8	Do you have any more detailed motor load information for the upper North Island and Waikato that would allow us to improve our modelling?

Only Northpower offered comment here, with other submitters reporting no more information, or not commenting.

Northpower noted that it had provided considerable input to Transpower's 2013 motor load survey for the UNI. Northpower noted too that its proportion of motor load is higher than many other networks due to the very large industrial sites and the amount of refrigeration load, and that progressive installation of variable speed drives (VSD's) over the years will have changed the characteristics of the motor loads presented to the grid.

Transpower response: *We are using our 2013 motor load survey for the upper North Island for this investigation and thank Northpower and others for their input into it. We have recently commissioned a similar motor load survey for the Waikato to support this investigation.*

We realise that motor load is continually evolving so we have increased the frequency of our surveys, but do not believe that the changes are likely to be enough to warrant another motor load survey for the upper North Island yet.

2.9 Existing generation in the UNI

Q9 Are you aware of any other existing generation in the UNI that we should include in our analysis?

EGL noted its 4.7MW of gas and diesel generation in Papakura.

Northpower noted that it has a small hydro station at Wairua, and that Trustpower has a diesel peaker at Bream Bay.

Transpower response: *Thank you for the information. We have begun the process of including embedded generation data from the Reconciliation Manager in our models so that we can better capture gross load.*

Auckland Council notes that while the amount of peak power available in the future is also an issue, this could be met by proposed new electricity generation or by existing power generation (i.e. if the aluminium smelter at Bluff terminates its contact with Meridian, approximately 570 MW would be available).

Transpower response: *Without significant new thermal generation in the UNI, we forecast both voltage stability limits and thermal limits to northwards transfer into Auckland. The voltage issues are the subject of this investigation, and the thermal issues subject to a separate investigation within Transpower.*

We could not transmit surplus Manapouri power into the UNI without grid upgrades, and while there have been some proposals for new electricity generation in the UNI, we are only aware of the committed generation noted in our consultation paper and refined in this document.

2.10 Dynamic reactive support

Q10	Are you aware of any other dynamic reactive support sources that we should assume?

There was no information on other dynamic reactive support sources provided.

Counties Power stated that we should include any material change to dynamic reactive support from the current Transpower project to install and commission reactive power controller for upper north island (under the UNIDRS GUP approval).

Transpower response: *All the dynamic reactive support devices approved under UNIDRS GUP have now been commissioned and are included in our base case, other than the installation and commissioning of a reactive power controller for the UNI.*

As stated in our consultation paper, we consider that it may be appropriate to fund some of the assets required to meet the need through the UNIDRS project, as an amendment to that GUP.

2.11 Generation scenarios

Q11	Do you think that the generation scenarios are appropriate for this project? If not, how could we improve them, especially with regard to our assumptions on generation that will be built at or north of Huntly?

Submitters agreed to or were silent on the generation scenarios, with the following exceptions:

2.11.1 Information on specific generation projects

Meridian provided confidential information relating to potential wind farm developments north of Auckland which could contribute to the voltage support requirements in the region.

Contact suggested that we remove the Hauauru ma raki wind from scenario 1.

Counties Power believes that the consent for Awhitu peninsula windfarm has lapsed, and suggests that Transpower check with the owner.

EGL informs us of its plans to build 20MW at Bombay GXP, dependent on the DGPP proposal.

Northpower was aware of previous proposals for large windfarms and tidal generation to be established north of Auckland. For confidentially reasons, Northpower cannot provide details but it understands that the organisations who proposed to construct and operate these generators previously engaged with Transpower as part of their planning processes. Given the changed environment with the thermal decommissionings, Northpower encourages Transpower to engage with those organisations again.

Top Energy explains that it is currently progressing the Ngawha Expansion Project, with an intention of constructing two new 25 MW geothermal power stations at Ngawha. It expects the first geothermal power station to be commissioned in 2020 or 2021 and the second in perhaps 2026 or 2027, depending on the wholesale electricity price path. As these are different to the dates Transpower assumed in its generation development scenarios in its consultation paper, Top Energy would be happy to discuss forecast commissioning dates for Ngawha with Transpower. See comments in Section 2.3.2 also.

Transpower response: *Transpower thanks participants for their feedback. We will follow up on those recommendations and consider potential plant for our market development scenarios.*

Where a specific project has been abandoned, we will ensure that it is not modelled as built in the near-term. The project could become viable in the longer-term, so we may include it in market development scenarios. We will engage with the owners of relevant abandoned projects to ensure this approach is appropriate.

2.11.2 Disincentives for UNI generation investment

Auckland Council believes that hydro and geothermal have very limited potential in the upper North Island, which combined with the recent thermal decommissionings and Genesis's reliance on a contract with other generators to retain the Rankine units in service, demonstrate that there is no cost-effective option for reliable power generation of the scale required in the UNI. Auckland Council recommends that the option of additional market generation be removed from the long-list options.

Mercury submits that, in regard to the generation build assumptions at Huntly or further north, we do not expect new peaking generation to be built so far in advance of the planned (2023) or “unplanned” (e.g., due to Tiwai exit) retirement of the Rankine units. Mercury expects that the phasing in of the new generation to replace the planned 2023 Rankine unit exit is likely to be much closer to 2023 than not, due to the risk of market overcapacity and oversupply for example. Mercury notes further that, were the Rankine units to exit the market ahead of the planned 2023 date, it is even possible that the commissioning of the new peaking generation would follow the Rankine retirements, due to lead times in procuring plant, consenting, construction and so on. Furthermore, Mercury does not anticipate the construction of a new Taranaki gas peaker (notwithstanding Junction Road and related projects) unless the Taranaki Combined Cycle unit is retired.

Vector notes that the Authority's proposed TPM creates disincentives for new generation to locate to the UNI (see also Section 2.7.1).

EGL believes that thermal generators and distributed generators will be discouraged by the prices this winter and the Authority's proposals on TPM and DGPP. A renewed survey of individual expansion plans could be useful.

Contact considers it is unlikely that there will any new gas fired generation built north of Huntly due to gas transmission charges.

Transpower response: *We agree that apart from Ngawha, significant new non-intermittent market generation in the UNI in the short to medium term appears unlikely, and have reflected this in our scenarios. In the longer term (2030+) we include some UNI generation in some scenarios, consistent with the EDGS.*

2.11.3 Energy storage to replace peaking plant?

MNZ comments that the EDGS do not reflect the potential for energy storage to replace gas peaker power stations, and submits that storage can have many advantages over gas peakers, including use at non-peak times for energy and ancillary services.

Transpower response: *We thank MNZ for the information. We agree that some scenario assumptions on future gas peakers could in principle be met by energy storage devices.*

Transpower would need to be confident that energy storage solutions 1) provided the services required reliably, 2) that operational and maintenance expertise was available locally, and 3) that the net benefit of batteries was higher than a traditional solution, taking into account the array of benefits that batteries could provide.

With those caveats, Transpower expects to engage with energy storage providers or aggregators to obtain cost information and greater technical assurance.

2.12 Analysis period

Q12 Is our proposed analysis period to 2045 reasonable for this project?

Submitters mostly agreed to or were silent on the proposed analysis period.

Mercury believes that Transpower should design a programme of works to address the UNI's voltage support requirements over the next thirty years, as the need will likely only grow with time given population trends and relatively limited prospects for major generation projects.

MEUG suggests that Transpower review this date for the economics of reactive support options following any further analysis of the limits of reactive support discussed in the consultation paper (in its Section 7.2.4). MEUG notes also that the Commerce Commission's forthcoming review of the Capex IM may consider the approach to setting the analysis period.

Transpower response: *We will use the period to 2045, unless we determine that the date of commissioning of our investment proposal is beyond 2025, in which case we will have to extend it commensurately to Capex IM requirements.*

We note the planned Capex IM review, that we may need to change the analysis period to be consistent with any changes made.

2.13 Value of unserved energy

Q13 Do you think $25,300/MWh is appropriate for valuing expected unserved energy for this project?

If you are a large industrial consumer, is $25,300/MWh appropriate to your own assessment of your cost of non-supply?

Submitters agreed to or were silent on the proposed value with the following exceptions:

2.13.1 Use the Authority's recent analysis

MEUG submits that Transpower should consider using the more recent analysis by the Authority, and Contact asks whether our value figure is consistent with the Authority's assumptions.

Transpower response: *Transpower has been undertaking value of unserved energy studies that are consistent with Authority's survey methodology. When our studies are complete, we will consider updating the value of unserved energy used. We will seek feedback on any updated figure in our short-list consultation for this project.*

2.13.2 Uncertainty in the value

Counties Power agrees to our figure for general loads, but believes that the value of unserved energy is unknown for major industrial loads in Counties Power's network.

Northpower submits that the value of unserved energy does not reflect the total cost to New Zealand of interruptions. Northpower notes that for many industrial plants that operate interconnected continuous processes, the loss of production is similar whether an outage lasts 5 minutes or an hour because, once processes are interrupted, they must be restarted progressively over a period of hours or days. Northpower adds that there are also potential wider impacts to the New Zealand economy (such as fuel shortages) which are specifically excluded from the assessments of the values of unserved energy but are, nevertheless, real costs that need to be considered.

Transpower response: *We agree that a $/MWh unit for the expected cost of unserved energy is only an approximation, as there is a duration dependency. For this investigation the prime risk that would cause unserved energy is voltage collapse, which if it occurred would be widespread and take some considerable time to recover from. We will endeavour to ensure that the* *value of unserved energy that we use is consistent with likely durations of unserved energy.*

2.13.3 Capex IM review

MEUG noted that the Commerce Commission's forthcoming review of the Transpower Capex IM may consider the approach to setting the valuation of expected unserved energy.

Transpower response: *We note the planned Capex IM review, and that we may need to change our value of unserved energy to be consistent with any changes made.*

2.14 Discount rate assumptions

Q14 Do you think our discount rate assumptions are reasonable?

If not, what discount rates would you consider more appropriate for this analysis?

Submitters agreed to or were silent on the proposed discount rate assumptions, with MEUG notes that the Commerce Commission's forthcoming review of the Transpower Capex IM may consider the approach to setting the discount rate assumptions.

Transpower response: *We will use the discount rates as proposed in our consultation paper.*

We note the planned Capex IM review, and that we may need to change our discount rates to be consistent with any changes made.

2.15 Transmission Pricing Methodology

Genesis believes that any proposal that has the potential to add to net peak demand should be carefully considered before implementing.

Auckland Council submits that one of the potential outcomes of the Transmission Pricing Methodology (TPM) review is an increase in electricity prices for the upper North Island and this could change the economic justification of the long list options currently under review for this consultation. In particular the changes in pricing could favour more local solutions rather than transmission upgrades.

MEUG notes as a problem that parties that are not beneficiaries or exacerbators of the need for expenditure related to this WUNIVM investigation would pay a share of the costs. MEUG suggest that a new short-listing criterion could be added ensuring alignment of parties that benefit from or are the exacerbators of the need for any investment or payments by Transpower for WUNIVM also pay for those costs, perhaps as an aspirational criteria until such time as the TPM is amended.

Transpower response: *Transmission investments are decided on the basis of market benefit. This excludes any value-transfer created by the TPM or by changes to the TPM.*

Transpower thanks all submitters for their comments on the TPM, but where they do not affect physical issues such as demand forecasts or generation scenarios, they have no direct bearing on this investigation. We have passed all submissions received on the TPM to our regulatory team.

2.15.1 Identifying TPM charge allocations of proposed investments

Northpower submits that if any of the short-listed solutions for the WUNI Voltage Management exceeds the threshold of an area of benefit (AoB) charge, Transpower's process must include establishing which participants would be included in the AoB and then engaging with them on the options.

Transpower response: *We intend to indicate in our short-list consultation document the likely impact on charges through the TPM. In that consultation, we will engage with all interested parties.*

2.15.2 Not investing until the TPM is resolved

Pacific Aluminium notes that NZAS is neither an exacerbator nor a potential beneficiary of any upgrades deemed to be necessary in WUNI, but that under the current TPM it would be required to contribute approximately 10% towards the cost of any investment made to the grid in this area. NZAS cannot afford to fund any further infrastructure for the benefit of the UNI and therefore opposes the proposed investment while the current transmission pricing arrangements remain in operation.

Vector does not support Transpower pursuing any investment solution for addressing future concerns about power quality for the UNI while the Authority is reviewing the TPM, which has created significant uncertainty about how the costs for transmission investments will be recovered.

Transpower response: *Given the urgency of the need we do not intend to defer this investigation or any required investments pending the Authority's decision on the TPM.*

The cost of an investment is recovered under the TPM from the date of commissioning of that investment, which for this investigation is unlikely to be for some years.

2.15.3 Transpower should not take input from incumbent generators

Vector notes also that the Authority's proposed TPM encourages incumbent generators to push for transmission investment projects, encouraging "rent-seeking" behaviour from incumbent generation and creates disincentives for new generation to locate to the UNI. In this respect, Vector encourages Transpower to explore means to avoid this type of "free-riding" such as limiting incumbent generator input into Transpower's investment projects given their limited contribution to Transpower's allowable revenue.

Transpower response:	*We do not intend to limit any party's input into this or other investment projects, to ensure that we have canvassed the full range of available information, options and views.*

2.16 Distributed Generation Pricing Principles (DGPP)

Genesis believes that any proposal that has the potential to add to net peak demand should be carefully considered before implementing.

Auckland Council notes the link between this investigation and the DGPP consultation as distributed electricity generation can be used to support the local network and reduce the need to increase transmission line capacity. The Council notes that changing the cost structure around distributed generation will affect its economics and the case for further investment. The Council notes too that review of the long-list of components needs to be based on the final pricing structure determined by both the TPM and DGPP consultations as any investment decisions need to reflect long term economic realities.

MEUG expects that by the time Transpower starts preparing a proposal based on this investigation to submit to the Commerce Commission, that the future of both transmission and distribution pricing will be clearer, which will assist in firming up winter peak demand forecasts, with the quality of the distribution pricing regime affecting the efficient of operating decisions by users of transmission services.

MEUG submits that it is unclear why this question refers to removal of the DGPP, as the proposed removal of the DGPP includes a requirement for Transpower to contract with existing parties that provide services to ensure grid limits are not exceeded, which seems clearly applicable to WUNI.

Transpower response:	*The proposed removal of the DGPP does not include any requirement for Transpower to contract with existing parties that provide services to ensure grid limits are not exceeded. Rather, the Authority notes – correctly – that Transpower has some existing and separate incentives to do so. An example is the consideration of GSCs for non-transmission solution in investigations such as this one.*

2.17 Capex Input methodology

MEUG notes that the Commerce Commission's forthcoming review of the Transpower Capex IM may consider the some of the generic Investment Test settings including the approaches to setting the analysis period, value of expected unserved energy and discount rate assumptions.

Transpower response:	*We note the planned Capex IM review, and that we may need to change some of the generic Investment Test settings to be consistent with any changes made.*

2.18 Thermal transfer issues

With regards to thermal transfer issues, Contact advises of a current issue with the low continuous rating (less that the summer thermal rating of the circuits) of the Tokaanu SPS, this will become the next constraint to bind once the Bunnythorpe reactor is commissioned, and welcomes feedback from Transpower on how this issue will be resolved.

Transpower response: *This is outside the scope of this investigation, but we have forwarded Contact’s request to our customer relations team.*

2.19 Market systems

Contact submits that in the longer term, we would like to see voltage solutions co-optimised with energy and other ancillary services within SPD.

Transpower response: *This is outside the scope of this investigation. We support the benefits of such an approach, but are well aware of the technical difficulties involved. As provider of the system operator service, we already have this on our radar for consideration for future market development.*

2.20 Extended reserves regime

MEUG is unclear on the detail of how the new North Island extended reserves regime will be implemented. MEUG has no particular aspects that may intersect with the investigation at this stage, but are taking a precautionary approach and are monitoring for any cross-topic issues.

Transpower response: *There is certainly potential for dependencies between the extended reserves regime and this investigation, for example in GSCs for load shedding. We will be considering the implications of any such interactions identified, and welcome the attention of MEUG to this issue.*

2.21 Transpower Works Agreement project

MEUG notes that it is engaging in Transpower’s draft Transpower Works Agreement project (TWA), aspects of which could be considered for the GSC product design, and offer to bring any cross-over topics to our attention.

Transpower response: *We thank MEUG for its engagement and look forward to receiving any further thoughts.*

3 Investigation update (May 2018)

This update provided further details of the investigation, and what stakeholders might expect in our proposal to the Commerce Commission. Major components of the evolving preferred investment option were presented, along with an indicative timeline.

We also provided information about the plan to build shunt capacitors in the Waikato as soon as possible under base capex.

4 Short-list stakeholder consultation (June 2019) - Summary of submissions with Transpower responses

This section summarises submissions received on Transpower's *Waikato and upper North Island voltage management short-list consultation* of June 2019[4]. We have endeavoured to summarise the submitters' key points. Please refer to their submissions for further detail, and to Appendix A.2 for how we addressed issues raised.

Submissions were received from:

- **ABB** Ltd a supplier of transmission utility solution products and services
- Contact Energy Limited (**Contact**), an electricity generator and retailer
- **Counties Power**, an electricity distribution company in the south-west Auckland region
- **Enel X** an energy management and demand aggregator
- Genesis Energy (**Genesis**), an electricity generator and retailer
- **Golden Bay Cement**, a major energy user based in the Upper North Island
- Mercury Energy (**Mercury**), an electricity generator and retailer
- Meridian Energy (**Meridian**), an electricity generator and retailer
- The Lines Company (**TLC**), an electricity distribution company in Waitomo and the King Country
- **Trustpower,** an electricity generator and retailer
- Vector Ltd (**Vector**), an electricity (and gas) distribution company in the Auckland region
- WEL Networks (**WEL**), an electricity distribution company in the Waikato

This section includes submitters' comments on the eight questions asked in the consultation report, plus general comments of relevance. The sub-section numbers below correspond to the question number. We provide our response where appropriate.

[4] The consultation paper, the non-confidential submissions and this document are available at transpower.co.nz/waikato-and-upper-north-island-voltage-management-investigation.

4.1 Voltage stability assumptions

Q1	Do you agree with our voltage stability assumptions? If not, what additional information could you provide?

All respondents to this question agreed with our voltage stability assumptions. Trustpower noted that anecdotal evidence of voltage instability already existed in Northland.

Other comments were:

ABB considered that the voltage stability assumptions defined in the report seemed reasonable. ABB provided a commentary on Transpower's modelling of voltage sensitive loads (particularly induction motors) in the distribution network, how the motors react during and immediately after a fault, and how different technologies such as SVCs or hybrid STATCOMS can operate to assist with under and over-voltage.

Transpower response: *There are a few small differences in how Transpower modelled and carried out the studies and ABB's feedback. We will investigate the effect of these small differences as sensitivity studies.*

Vector considered voltage sensitive load assumptions should be verified against actual voltage events. The company also noted that future distributed generation connected to their network would have volt-var response, likely leading to an improvement in voltage stability.

Transpower response: *We have observed local voltage events that resulted in loss of voltage sensitive load at a single or a small number of GXPs, which indicate our voltage sensitive load assumptions do reflect the actual quantity of voltage sensitive load connected to the system.*

We have not observed voltage events that resulted in a widescale significant loss of voltage sensitive load because of the historical amount of generation in the Auckland and Waikato regions. This has changed with the retirement of Otahuhu C, Southdown, and two Huntly Rankine units and the announced retirement of the remaining two Huntly Rankine units. This leaves only one major dispatchable generation unit in service (Huntly Unit 5) in a region with >3000 MW of load (from 2022). Therefore, we expect the most severe voltage events to result in the widespread loss of voltage sensitive load in the future.

After the Rankine retirements, we will closely monitor the response of voltage sensitive load and update our assumptions accordingly. This is an advantage of the staged investment approach proposed by this investigation.

The need of the project is not driven by the response of distributed generation although, in the future, the large-scale penetration of distributed generation with volt-var response may assist with mitigating the voltage stability risk. We do not expect significant uptake in these technologies during our immediate investment horizon (2022-2025).

4.2 Market commitments

Q2	Do you agree with our proposed approach to handling any significant market commitments in the course of this project?

Respondents agreed with our proposed approach to managing market commitments. Genesis stated that NTS should be prioritised until generation investment decisions are committed. Meridian advised that acting soon would help avoid any demand management or constraint tightening due to early decommissioning of thermal generation. Trustpower supported the approach provided we were agile when new information was received.

Transpower response: *We undertook an RFI for NTSs during our long-list consultation in 2016. Given the evolution of the project since then and the improved information we now have on the magnitude and performance that would be needed for NTSs to be effective, we will undertake a second RFI in October 2019. If we receive responses to this RFI that suggest there are economic NTSs sufficient to defer part of our transmission solution by a meaningful length of time (at least 3-4 years).*

Until we receive responses to this RFI we are unable to determine if NTSs are suitable to defer or avoid transmission solutions or mitigate the risk of early generation retirement. If there are no economic NTSs available and no commitment to keep the Rankines operating beyond the stated retirement date at the end of 2022, we will proceed with our investment proposal. We consider this is a prudent course of action given the significant costs New Zealand electricity consumers are expected to bear if we do not invest and the Rankines were retired as announced.

We will withdraw or amend our application if a material market commitment is made before we have committed to delivering the project.

4.3 Project need

Q3	Are there any other considerations relating to the need that we should incorporate into this project?

Submitters raised a number of considerations. Vector expressed concern about the operation of the proposed demand management scheme (our response is covered in Section 4.12).

Trustpower wanted more information about whether the preferred transmission solution could be flexible to an NTS that provided part of the voltage stability need (this is covered in Section 4.4 below).

ABB recommended we study and evaluate STATCOM and Hybrid STATCOM solutions in addition to classic SVC technology when we refine our generic dynamic reactive device assumptions.

Other comments included:

WEL raised concerns around the management of steady state high voltages at light load and whether the short-listed options considered the impact on system operations. WEL also recommended that steady-state high-voltages be considered at the same time as TOV.

Transpower response: *The primary need driving our investigation is to manage dynamic under and over-voltage events. However, options that include SVCs/STATCOMs would allow the system operator to better manage static high voltages during light load periods.*

As described in Section 4.6 of the Options and Costing report, we consider steady-state voltages benefits as an unquantified benefit of each short-listed option.

Contact queried whether we had given consideration to an interim NTS to manage voltage stability arising from unexpected demand growth, early decommissioning of generation, or delays to the procurement of dynamic reactive support devices. Contact said an interim NTS would provide price certainty for WUNI consumers against the tightening of voltage stability constraints.

Transpower response: *We intend to seek information on possible NTSs that provide voltage support prior to our current need date (December 2022) as part of our October 2019 RFI. We would only contract with such an NTS if the risk of unexpected market events outweighed the cost of the NTS.*

Contact also asked if the demand forecast accounted for the expected step change in demand in the Counties Power region and the potential removal of the TPM RCPD peak demand charge.

Transpower response: *We forecast ~85 MW of demand growth at the Bombay 110 kV GXP during the 2019-2030 period (possibly to be later supplied from a new GXP at Drury). This growth is primarily driven by new residential connections and commercial/industrial development.*

The potential removal of RCPD pricing increases the uncertainty of future peak demand. We do not explicitly model the removal of RCPD pricing in our demand forecast due to a lack of data on the magnitude of price responsive demand but agree it could result in peak demand increasing. We note an increase in peak demand brings forward the need for investment in dynamic reactive devices.

Counties Power suggested we consider the impact of less certain market behaviours on our demand forecasts, including emerging technologies and decarbonisation. Mercury also questioned to what extent Transpower had considered the impact of changes to the composition of load on motor load assumptions due to emerging technologies (e.g. EV charging).

Transpower response: *We agree emerging technologies have the potential to impact both the magnitude and composition of demand, including the amount of voltage sensitive load as a proportion of total system load.*

In the demand forecast used in our proposal to the Commerce Commission, we will incorporate the latest EDGS published by MBIE in July 2019 which includes explicit modelling of electric vehicles, solar PV and batteries. Nevertheless, we do not expect emerging technologies to materially affect our demand forecast assumptions or the project need during the immediate investment horizon (2022-2025).

From 2025, we expect the total magnitude of voltage sensitive load to increase during the life of any assets commissioned (e.g. heat pumps for the electrification of low temperature process and space heating). However, a large uptake of distributed batteries may reduce the need for further transmission investment in voltage stability equipment. On balance, we expect the need for the project to increase rather than decrease due to emerging technologies.

4.4 Non-Transmission Solutions (NTS) approach

Q4	Do you agree with our approach to non-transmission solutions?

Most respondents agreed with our approach.

Mercury recommended Transpower provide more details of the dynamic voltage need as part of the NTS procurement process. They also commented that details of the expected magnitude, frequency and duration of dynamic voltage support would make it easier for potential NTS providers to assess whether their solutions would be competitive to the transmission-only solution.

Counties Power raised concerns around demand management scheme operations. (Our response to the demand management scheme is covered in Section 4.12).

Other comments included:

Trustpower queried whether we would be flexible to NTSs that only delivered part of the need.

Transpower response: *We are interested in NTSs that if combined are large enough to economically defer at least one dynamic reactive device by at least 3-4 years. Anything smaller than this would not meaningfully reduce the cost to meet the need given the long lead time to investigate and deliver transmission equipment solutions. A possible exception to this is NTSs for risk management (addressed in Section 4.2).*

Details about NTS options that could combine as a group to meet the minimum size requirement will be included in our October 2019 RFI.

Trustpower also commented that the proposed timeline to consent, procure, install and commission an NTS seem very optimistic.

Transpower response: *There are benefits in waiting until closer to the need date, including lower technology costs, reduced generation and demand uncertainty, and greater clarity on the magnitude of NTSs required.*

Overall, we consider the lead time is sufficient given we are able to design, procure and deliver complex transmission equipment in the same timeframe.

ABB commented that an NTS is an interesting solution and could provide additional system benefits if it were to result in a combination of several technologies, where each different technology contributed its best characteristics to optimise power performance.

Transpower response: *We are open to procuring voltage support as a service from any technology that can meet the performance criteria outlined in our October 2019 RFI.*

4.5 Economic assumptions

Q5	Do you have any comments on the economic assumptions we intend to use in our application of the Investment Test?

Most respondents considered the assumptions made were appropriate.

Counties Power had concerns about how the value of lost load was developed into unserved energy costs and wanted greater transparency on the calculations. Similarly, Enel X said it was difficult to fully review the economic assumptions as the key parameter of MWh delivered per annum was not clearly defined.

Transpower response: *We will detail the expected magnitude of NTSs we require in the October 2019 RFI.*

As part of our proposal to the Commerce Commission we will provide more details of our economic analysis. Under the Commission's processes, interested parties will have another opportunity to review and respond to any additional information.

4.6 Quantified costs and benefits

Q6	Do you have any comments on our analysis of and quantification of costs and benefits for this project?

Submitters raised a number of comments regarding our analysis of cost and benefits, including:

Genesis queried the sensitivity of our options to the retention of their Huntly Rankine units beyond 2022.

Transpower response: *We will include a sensitivity with the Rankine units remaining in service in our proposal to the Commerce Commission.*

ABB recommended we consider the operating cost difference between SVCs and STATCOMs when evaluating dynamic reactive devices.

Transpower response: *We will include this as part of our tender evaluation of dynamic reactive devices.*

Enel X found our analysis of cost and benefits unclear as not all assumptions or costs were defined.

Transpower response: *We will provide more detail of our economic analysis in our proposal to the Commerce Commission.*

Also see our response in Section 4.5.

Meridian was unsure how we quantified the benefits to consumers of increased security (N-G-1).

Transpower response: *We assume the system operator will undertake pre-contingent demand management if demand is above the N-G-1 limit and Huntly Unit 5 is not operating due to an unplanned outage. This cost forms part of the unserved energy costs in our assessment.*

In our proposal to the Commerce Commission, we will quantify the dispatch costs of constraining-on generation in the WUNI region to the N-G-1 limit (if this cost is material).

Counties requested we provide the estimated change in interconnection costs of each option, rather than just for the preferred option.

Transpower response: *This information will be included in our proposal to the Commerce Commission.*

WEL commented that the O&M costs presented seemed low compared with the annual Maintenance Recovery Rate for substation equipment in the TPM.

Transpower response: *We will review our O&M assumptions before submitting our proposal to the Commerce Commission.*

4.7 Unquantified costs and benefits

Q7	Do you have any comments on our qualitative assessment of unquantified costs and benefits for this project?

Few submitters responded to this question. Counties Power considered the gravity of a demand management scheme dropping an entire GXP did not appear to be properly reflected (covered in Section 4.12).

Other comments included:

Mercury and Contact raised the importance of considering competition benefits across the investment options.

Transpower response: *As set out in our short-list consultation, we intend to treat competition benefits as an unquantified benefit due to the complexity of analysing these benefits (however, as noted in Section 4.6 we intend to quantify the dispatch benefits of each short-list option if material).*

ABB suggested that unquantified benefits include those associated with a specific dynamic reactive device technology including device reliability, availability and footprint requirements.

Transpower response: *We will include this as part of our tender evaluation of dynamic reactive devices.*

4.8 Approach to determine a preferred solution

Q8	Do you agree with our intended approach to determine a preferred solution and our intended application of the Investment Test?

Most respondents agreed with or did not comment on our intended approach and application of the Investment Test.

Other comments included:

Mercury said the effectiveness criteria would be a critical factor in determining whether NTS were employed, and Enel X agreed that the criteria and weightings should be well justified and presented clearly in the procurement process.

Transpower response: *We agree the effectiveness criteria is an important factor. In our upcoming NTS RFI we will provide information on the expected magnitude and performance that NTSs would need to meet to be effective. There will be other criteria (e.g. location) that will be better analysed quantitively after we receive more information from potential providers through this RFI. If responses appear to be economically viable, we will analyse them to determine if they are indeed potential candidates.*

Should NTS(s) appear economically viable, we will formally engage with the market through an RFP process which will include detailed evaluation criteria to determine the best solution for New Zealand electricity consumers. We will provide updates on the NTS process to interested parties on our project webpage (transpower.co.nz/waikato-and-upper-north-island-voltage-management-investigation).

Counties Power commented that the approach was correct, however the valuation of impacts and overall evaluation required serious reconsideration.

Transpower response: *Given Counties Power's comments on other questions, we take this comment to relate specifically to the post-fault demand management scheme. See our response in Section 4.12.2.*

Trustpower sought more information about the preferred solution and whether it could be implemented in stages, thereby allowing market participants to each provide part of the solution. Trustpower stated that if other parties provide part of the solution then the project costs must reflect their contribution.

Transpower response: *See our comment in Section 4.4.*

Meridian commented that we should update the market if we consider revisions to our proposal were likely.

Transpower response: *We agree and will update the market following any significant generation announcements or responses to our October 2019 NTS RFI that materially impact our proposal to the Commerce Commission.*

4.9 Synchronous condensers

WEL suggested we include the benefits of synchronous condensers in our short-list due to their benefits in providing inertia and fault level contribution.

Transpower response: *We are aware of the issues of falling inertia and fault contribution in power systems overseas due to the decommissioning of thermal power stations and how synchronous condensers can assist with mitigation. We do not currently experience, or foresee, any such issues materially impacting the grid within the immediate investment horizon.*

As explained in our short-list consultation, we consider synchronous condensers as dynamic reactive devices that we have represented by using the shorthand 'SVC'. Synchronous condensers provide system strength and some dynamic support (although typically less than SVCs and STATCOMs due to their slower speed of response). We do not expect the system strength benefits of a new synchronous condenser to be sufficient to meet the need of the project and be cost-competitive with SVCs or STATCOMs. However, we are open to receiving tenders for synchronous condensers through our transmission equipment *procurement process should they meet our performance criteria for dynamic reactive devices.*

We also remain open to procuring NTS services from existing synchronous condensers or through conversions of existing generation plant and will seek additional information in our October 2019 RFI.

4.10 Impact of voltage fluctuations

Golden Bay Cement commented on the high impact that voltage fluctuations have on their production process, and supported investment in the grid that results in a more stable supply where the benefits of doing so are reasonable relative to the cost passed on to consumers.

Transpower response: *We agree a reliable and economically efficient service from the grid is critical to New Zealand electricity consumers.*

4.11 Independent review of options analysis

Vector requested we commission an independent review of our short-list and costs and benefits before finalising our proposal.

Transpower response: *We have engaged external consultants to provide technical advice to our power system modelling team throughout the project. Furthermore, we engaged Zia Emin (Chairman of CIGRE Study Committee on System Technical Performance) to provide an external review of our analysis of over-voltage stability.*

Finally, we expect the Commerce Commission will review our short-list, costs, and benefits when evaluating our proposal.

4.12 Demand management scheme

Several submitters raised concerns relating to the proposed demand management scheme. They considered the consultation document lacked specific detail as to how the scheme would be implemented, and whether consumers would be compensated.

4.12.1 Participation and compensation

Vector considered all non-critical GXPs in the region should participate in the scheme.

Counties and WEL expressed concerns about the proposed operation of a demand management scheme, particularly around the possibility that the entire GXP load might be dropped.

TLC objected to any use of demand management through the disconnection of GXPs, and said we had not fully considered the cost to consumers.

Transpower response: *There are technical constraints that would prevent some GXPs in the WUNI region from participating in the scheme. For example, not all GXPs are equally effective at tripping load to prevent voltage collapse, and most of the less effective GXPs would be excluded to prevent the scheme affecting system frequency. Some GXPs may be excluded due to their load composition, specifically a high quantity of motor load which could cause an overcorrection of voltage and an over-voltage event.*

Furthermore, each GXP that participates in the scheme will increase the capital cost to implement the scheme by ~$500,000. Given the very low probability that the scheme will operate, we do not consider including more GXPs than required to be economically justified relative to the increase in capital cost at this time. In the extremely unlikely event the scheme did operate, we would consider adding new GXPs to ensure the same consumers were not at risk a second time (if doing so did not reduce the effectiveness of the scheme).

Of those GXPs that are technically feasible we intend to select those that minimise the capital, operating and unserved energy costs of the scheme.

Due to the feedback we have received from submitters, we intend to modify the design of the scheme with the aim to exclude critical feeders where:

- *feeders have a materially higher VoLL*
- *excluding them reduces the total cost of the scheme (including capital and unserved energy costs)*
- *it does not prevent us having the required quantity and type of load in the scheme.*

We will work closely with our affected customers to identify such critical feeders.

WEL said participants in the scheme should be able to opt in and be compensated.

Transpower response: *We are proposing this scheme to reduce the frequency, duration, and cost of interruptions for all customers and consumers in the WUNI region relative to us doing nothing to manage the voltage stability risk. Therefore, we do not intend to provide direct compensation to any affected customers and consumers in the extremely unlikely event the scheme was to operate.*

While there may be some merit in having consumers that benefit from the scheme paying those consumers who participate in the scheme, given the very low probability of the scheme operating we expect the costs of administering such an arrangement would be greater than its benefit.

4.12.2 Interruption to supply

Vector was concerned the scheme would result in more interruptions for Auckland consumers, and that there is a possibility the scheme could operate unintentionally. Similarly, TLC and Counties commented that we had not appropriately considered, or had underestimated, the cost of interruption to consumers from the post-contingent demand management scheme in our cost-benefit analysis.

Transpower response: *While we strive to provide a highly reliable transmission network we also recognise the need to do this in an efficient manner that does not unduly impose costs on consumers.*

The proposed scheme will reduce the frequency, duration, and cost of interruptions for all WUNI customers and consumers relative to us doing nothing to manage the voltage stability risk.

This scheme is expected to maximise net-electricity market benefits after taking into consideration both the expected unserved energy cost from the scheme operating and the capital cost of alternatives. The scheme is a risk management tool that would be used as a last resort to prevent a complete blackout of the WUNI region, possibly spreading to the whole North Island, for an extended period.

The scheme would have a very low probability of operating. The Grid Reliability Standards and Investment Test require us to consider the expected cost of unserved energy (i.e. probability × consequence). As a low probability event it means the overall expected cost of the scheme is low compared with every other potential solution we identified, which all had lower net benefits.

We will review our economic assumptions and analysis prior to submitting our proposal to the Commerce Commission.

We will design the scheme to mitigate the risk of the scheme operating unintentionally to the greatest extent possible, both in the hardware implementation and the logic used to detect voltage collapse. Note, for the scheme to meet its objective of preventing a complete blackout of the WUNI region and possibly the whole North Island, it must trip load fast and in large blocks. Delayed tripping and small scale incremental tripping to attempt to minimise the amount of load disconnected carries a high risk of not preventing a voltage collapse.

The scheme's preliminary design includes the following risk mitigation features:

1. *The scheme will measure the voltage at four different 220 kV buses and send a signal to GXPs in the scheme if voltage collapse is detected. Three of the four signals must indicate voltage collapse before further action is taken (the fourth bus provides redundancy in case of equipment failure). As an additional safeguard, the local GXP voltage will also be measured and blocks further action if the local voltage is healthy. If these conditions are met, local feeders are tripped in several approximately equal tranches with a small time delay between tranches. Highly critical feeders are not tripped.*

2. *Detection of voltage collapse at the four 220 kV buses is based on a voltage-time criterion, not just low voltage. A few distribution faults may be detected as a voltage collapse at one 220 kV bus, but not at three or four buses unless there is a significant impact on*

> *the transmission system. The vast majority of faults will not be detected as voltage collapse. However, the voltage-time criteria must be set with a slight bias so it never fails to detect a voltage collapse that would result in a widespread blackout.*

Therefore, the scheme's hardware will be very robust against maloperation, especially widespread maloperation and its control logic will be as robust as possible against correct avoidable operations.

4.12.3 Solutions without post-contingent demand management scheme

Vector commented that a solution to the under-voltage need is possible without a post-contingent demand management scheme.

Transpower response: *It is possible to meet the need of the project without a post-contingent demand management scheme. Our short-listed options include those with a post-contingent demand management scheme (options 1-3, 5-6), and one option without the scheme (option 4). Option 4 manages the under-voltage risk with additional capital investment (in this case by bringing forward future components including the series capacitors and additional dynamic reactive devices). However, this comes with a significant extra capital cost with very little reduction in unserved energy costs. Therefore, we consider option 4 does not meet the Grid Reliability Standards and Investment Test. See also our response in Section 4.12.1..*

4.13 Voltage stability limits

Vector commented that the impact of the proposed dynamic reactive devices on the voltage stability limits was not clear.

Transpower response: *The two +/- 150 Mvar dynamic reactive devices increase the N-G-1 under-voltage limit from 2750 to 2990 MW, and the N-1 under-voltage limit from 3170 to 3295 MW. The post-contingent demand management scheme allows the system operator to operate to a higher N-G-1 limit of 3170 MW (referred to as the N-G-OTA-WKM limit in the Power System Analysis and Options and Costing reports).*

In addition, the dynamic reactive devices also increase over-voltage limits. We will provide these in our proposal to the Commerce Commission.

4.14 Benefit of voltage stability investment prior to reconductoring

Meridian considered investment in voltage support should occur before any major reconductoring projects in the WUNI region.

Transpower response: *We agree – taking major 220 kV circuits out of service will lower voltage stability limits, and therefore increase the cost to the market of meeting* *these limits for the duration of the outage. This will be included as an unquantified benefit in our proposal to the Commerce Commission.*

4.15 Cost of 400-kV conversion

Vector questioned how we calculated the costs associated with the 400-kV conversion of the Pakuranga to Whakamaru circuits in order to rule this out as a short-list option.

Transpower response: *The NIGUP proposal estimated the cost of the 400-kV conversion as greater than $300m (in 2006 dollars). Including the series capacitors (required prior to the conversion) and inflation, it would likely be greater than $500m. This is clearly more than our short-listed options during our immediate investment horizon (e.g. $140m for option 2). Such a large one-off investment does not retain option value for changes to market conditions; therefore, given the current generation uncertainty, is not economically prudent at this time.*

A.1 How we addressed issues raised in Long-list consultation submissions

In our summary of submissions, we undertook to take certain actions in response to feedback received. These issues and how we have addressed them are itemised in Table 1.

Table 1 - How we addressed submissions to the Long-list consultation.

Issue	Section	Comment
We will consider revising our **GSC design** to include long-term GSCs for market generation, including for transmission avoidance, if this emerges as an economic solution to this investigation (or in response to any relevant regulatory changes).	2.3.1	In our October 2019 RFI for NTS, we sought contracts for up to 10 years.
We will add to the **short-listing criteria** 'Is the solution robust and adaptable to the range of foreseeable outcomes'.	2.5.1	Completed – see Section 3.1 of our Options and Costing report.
We will ensure that one of our **scenarios** includes the early retirement of Tiwai with consequent earlier retirement of the Huntly Rankine units.	2.5.1	Since this comment was made in 2016 the July 2019 EDGS were published, which form the basis for the demand and generation scenarios in our proposal. The updated EDGS do not include Tiwai retiring in any of the five demand scenarios, so we have not included one in our proposal. If the Rankines were to rely early, the need date for investment would move forward, strengthening the case for investing now as proposed in this MCP.
We will be considering installing **static capacitor banks** to support low voltage buses to raise the overall voltage profile across the North Island transmission system.	2.2.1	We are planning to commission static capacitors in 2020 to assist with the overall voltage profile. Furthermore, we have included static capacitors as a short-list component in some options.
We will be considering the **combination of static and dynamic reactive assets** that provide the greatest net benefit.	2.2.1	We have done this in our choice of short-listed components and in our power systems analysis.
We will be considering the contribution of **synchronous condensers** to meeting the need, and their economics, and may in due course issue an RFP for a **GSC** for such services.	2.2.2	We are addressing this through our NTS RFI and subsequent procurement process (if viable NTS are identified).
Our **GSC** design document could be more explicit on how **batteries** will be treated: we will update the document in due course to make this clearer.	2.2.5	Our October 2019 NTS RFI provided our requirements for NTS providing dynamic voltage support (including batteries).
We will discuss with **Top Energy** their plans and possibilities for the Ngawha generation.	2.3.2	Transpower has had continued discussions with Top Energy on this.

Issue	Section	Comment
We will offer **GSCs** for temporary peak load reduction, for the purposes of managing build risk, where they are practical, reliable and economic.	2.3.3	We are addressing this through our NTS RFI and subsequent procurement process (if viable NTS are identified).
We will consider revising our **GSC design** if permanent peak load reduction emerges as an economic solution.	2.3.3	We consider permanent peak load reduction is unlikely to be an economic solution. However, our October 2019 RFI provided detail on the magnitude of permanent peak load reduction required and we sought information on this type of NTS through this RFI.
We will advise all submitters of our timetable for issuing any **RFPs**.	2.4.2	Our procurement process for both transmission and non-transmission have been communicated via project communications, the WUNIVM website, and the procurement website gets.govt.nz.
If pre-fault load reduction becomes part of the solution to this investigation, we will consider the costs and benefits of improvements to the System Operator's medium- or short-term **load forecast** to make demand response more effective.	2.4.3	Pre-fault load reduction is not part of our preferred solution.
We consider option values and the possibilities of staged or 'triggered' investments in all our investment investigations but will give particular focus to them for this one.	2.5.1	We are submitting our proposal as a Major Capex Project (Staged). We have quantified the option value due to demand uncertainty for our short-list. Furthermore, we have considered the option value due to generation uncertainty as an unquantified benefit.
This investigation is focused on addressing voltage management issues rather than all issues, but within that scope we will be considering resilience. We consider resilience as a component of reliability. Levels of resilience need to be justified economically, and our primary approach to this is through considering high impact low probability events (HILPs).	2.5.2	HILP events are included in our assessment of unserved energy costs and our unquantified benefits and form the foundation of our consideration of a post-fault demand management scheme.
Transpower will undertake sensitivity testing to low and high demand growth as required by the Capex IM.	2.6.1 & 2.7.2	We have included this in our sensitivity analysis in Section 3.4 of our MCP Proposal document.
Transpower will continue to monitor developments with removal of DGPP and RCPD charges and consider how this uncertainty can be captured in our investigation. We will continue to monitor changes to the TPM and consider how they might increase peak forecasts.	2.7.1 & 2.6.1	We will continue to monitor such developments and changes through our load forecasting process.

Issue	Section	Comment
Transpower will engage with distribution companies and direct connects in the area to obtain information about the level of load control. However, we have found in the past that reliable data on the level of load controlled at peak times is difficult to come by.	2.7.2	We have regularly engaged with distributors and direct connects as an input to our demand forecasting process.
We will follow up on participants recommendations on specific generation projects and consider potential generators for our market development scenarios. Where a specific project has been abandoned, we will ensure that it is not modelled as built in the near-term. The project could become viable in the longer-term, so we may include it in market development scenarios. We will engage with the owners of relevant abandoned projects to ensure this approach is appropriate.	2.11.1	We have removed some generation projects from our generation scenarios in response to feedback on our last consultation. We have used the latest EDGS (published July 2019) in order to incorporate the most recent information on generation projects.
We will use the **analysis period** to 2045, unless we determine that the date of commissioning of our investment proposal is beyond 2025, in which case we will have to extend it commensurately to Capex IM requirements.	2.12	Our latest commissioning date is not beyond 2025, so we are using the 2045 date – as supported through feedback received from consultation.
Transpower has been undertaking **value of unserved energy** studies that are consistent with Authority's survey methodology. When our studies are complete, we will consider updating the value of unserved energy used. We will seek feedback on any updated figure in our Short-list consultation for this project. On the **value of unserved energy**, some submitters sought assurance that we would reflect the Electricity Authority's latest analyses and likely outage durations in the value used, which we will do. We will endeavor to ensure that the **value of unserved energy** that we use is consistent with likely durations of unserved energy.	2.13	We have used the standard VoLL specified in the Code, inflated to 2019 dollars. This value is similar to the GXP specific VoLLs from our 2018 study.
We will use the **discount rates** as proposed in our consultation paper.	2.14	We have used the discount rates as proposed in our Long-list consultation paper.
We intend to indicate in our Short-list consultation document the likely impact on charges through the TPM. In that	2.15.1	This was presented in our short-list consultation document and has been included in our MCP proposal.

Issue	Section	Comment
consultation, we will engage with all interested parties.		
We will be considering the implications of any identified dependencies between the extended reserves regime and this investigation, for example in GSCs for demand management	2.20	GSCs will not be offered if they would compromise other security products, including ancillary services and extended reserves, or the markets for these products.

A.2 How we addressed issues raised in Short-list consultation submissions

In our summary of submissions, we undertook to take certain actions in response to feedback received. These issues and how we have addressed them are itemised in Table 2.

Table 2 - How we addressed submissions to the Short-list consultation

Issue	Section	Comment
There are a few small differences in how Transpower modelled and carried out the voltage studies and ABB's feedback. We will investigate the effect of these small differences as sensitivity studies.	4.1	We carried out a sensitivity study using the model given in ABB's feedback for the distribution network and loads. The sensitivity study did not show a material change in results compared to the model we used. For clarification, in our studies we explicitly model all supply transformers (typically 220/33 kV or 110/33 kV). The transformer in our load model represents the impedance of the cables, overhead lines and transformers in the distribution network. The small difference between the two models is the connection point of the static load.
After the Rankine retirements, we will closely monitor the response of voltage sensitive load and update our voltage sensitive load assumptions accordingly.	4.1	Ongoing
We will seek information on possible NTSs that provide voltage support (including those able to provide support prior to the need date) during a second RFI for NTS in September 2019.	4.2	On 2 October 2019 we issued our RFI for non-transmission solutions. This RFI included provision for solutions that can provide support prior to the need date.
We will withdraw or amend our application if a material market commitment is made before we have committed to delivering the project	4.2	Ongoing
Details about NTS options that could combine as a group to meet the minimum size requirement will be included in our RFI	4.4	This was included in our RFI issued 2 October 2019
We will detail the expected magnitude of NTSs we require in the upcoming RFI.	4.5	This was included in our RFI issued 2 October 2019
As part of our proposal to the Commerce Commission we will provide more details of our economic analysis including how the value of lost load is developed into unserved energy costs	4.5	This is included as *A2. Unserved energy analysis methodology and assumptions* in Attachment C: Options and Costing Report.
We will include a sensitivity with the Rankine units remaining in service in our proposal to the Commerce Commission	4.6	Based on our current prudent demand forecast, we would require at least one dynamic reactive device in 2023 if the

Issue	Section	Comment
		Huntly Rankine units remain in-service, with another likely to be required in 2-3 years if demand continues to grow in-line with this forecast.
We will include the consideration of operating cost difference between SVCs and STATCOMs as part of our tender evaluation of dynamic reactive devices	4.6	Ongoing
We will provide more detail of how we analysed the costs and benefits to consumers of increased security for our economic analysis in our proposal to the Commerce Commission.	4.6	Complete – as described in Section 3.3.2 in our main proposal and Attachment C: *Options and Costing Report*.
We will quantify the dispatch costs of constraining-on generation in the WUNI region to the N-G-1 limit (if this cost is material).	4.6	We have included competition benefits in our 'unquantified benefit' analysis. We found that the dispatch costs of constraining-on generation to be immaterial, so they have not been included.
We will provide the estimated change in interconnection costs of each option, rather than just for the preferred option	4.6	We have included the estimated change in interconnection cost of each option in our proposal. Please refer to Options and Costing Report, A.1.
We will review our O&M assumptions before submitting our proposal	4.6	We have refined our O&M costs for this MCP submission
In our NTS RFI we will provide information on the expected magnitude and performance that NTSs would need to meet to be effective.	4.8	This was included in our RFI issued 2 October 2019
We will provide updates on the NTS process to interested parties on our project webpage	4.8	Ongoing
We will update the market following any significant generation announcements or responses to our NTS RFI that materially impact our proposal to the Commerce Commission	4.8	Ongoing
Due to the feedback we have received from submitters, we intend to modify the design of the demand management scheme with the aim to exclude critical feeders where: • feeders have a materially higher VoLL • excluding them reduces the total cost of the scheme (including capital and unserved energy costs)	4.12	Ongoing

Issue	Section	Comment
• it does not prevent us having the required quantity and type of load in the scheme. We will work closely with our affected customers to identify such critical feeders.		
We will review our economic assumptions and analysis in relation to the demand management scheme prior to submitting our proposal	4.12	We have reviewed our input assumptions (including probability) for our analysis in the preparation of this major capex proposal. This review of assumptions has not had an impact on our preferred option.
We will provide the impact of dynamic reactive devices on increasing over-voltage limits in our proposal.	4.13	This has been included in our proposal. Please refer to Attachment B: Power Systems Analysis report.
Taking major 220 kV circuits out of service will lower voltage stability limits, and therefore increase the cost to the market of meeting these limits for the duration of the outage. This will be included as an unquantified benefit in our proposal.	4.14	This has been included as part of the 'operational' unquantified benefits of our proposal.

