TRANSPOWER

Future Grid Blueprint Methodology

Te Kanapu Technical Approach

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DOCUMENT REVIEW AND APPROVAL

Reviewed by:

Reviewer	Title	Signature	Date
Stephen J Jones	Grid Investment Group Manager		9/12/2025
Stuart MacDonald	System Planning Group Manager		9/12/2025
Ramu Naidoo	Market Operations Manager		9/12/2025
Andrew Sykes	Technical Director – Future Grid	A G Sykes	9/12/2025

Approved by:

Approver	Title	Signature	Date
John Clarke	Executive GM Future Grid		9/12/2025

Contents

1.0 Background and overview

1.1 Background

The Te Kanapu Technical Approach suite of documents outline how Transpower is working to develop its draft future grid blueprint. By publishing these documents, we are sharing all the data, inputs and information being used in this process, for review and feedback.

Within this suite of documents are publications we have completed within Transpower and work that has been commissioned from others. For an outline of all the documents published under our technical approach, please see *Technical Approach Summary.*

This document, *Future Grid Blueprint Methodology*, covers the detail of the market modelling (economics) and power system analysis (engineering) we perform to develop our future grid blueprint. Here we outline the analysis (engineering, economic and otherwise) that will be used to determine the future grid blueprint.

While every effort has been made to ensure this information is of the highest possible quality, many assumptions are made across our work. This information should not be used for any purpose other than to inform discussions on a future grid blueprint.

The possible options mentioned throughout this document are concepts only to help guide conversations.

We want to hear from you

The approach we are taking is collaborative: we are developing this future grid blueprint by gathering feedback and we welcome your input into this work.

Please get in touch by emailing feedback@transpower.co.nz.

Publishing feedback

We will publish a summary of the feedback we receive throughout this process on www.transpower.co.nz/our-work/te-kanapu; especially where we have changed our approach as a result of the feedback we hear.

Transparency is important in this process. Unless requested by you, we will include both your name and any information you provide as part of your feedback, on our website.

If there is any aspect of your feedback that is confidential, please make this clear to us.

For more information

Visit the Te Kanapu section on the Transpower website to find out more. There you will find the background to our work, previous and current consultations, and additional data and analysis that has been used in our work to date.

www.transpower.co.nz/our-work/te-kanapu

1.2 Overview

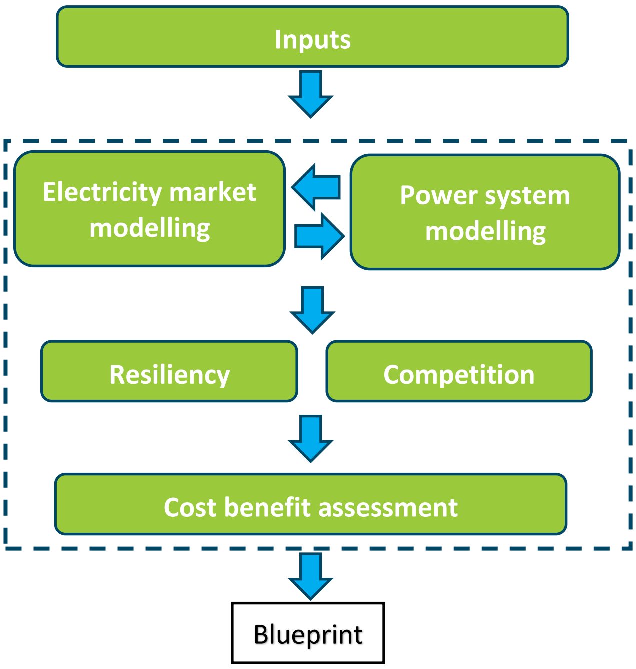
The purpose of this document is to improve transparency on our process, invite feedback, and begin a conversation on how best we plan and optimise transmission investment to suit the needs of all people in New Zealand.

In this document, we outline our process for determining the future grid blueprint. This process is shown in **Figure 1**.

Inputs include demand scenarios, generation expansion, inclusion of consumer energy resources (CER), and flexible electricity resources.

This document outlines the steps within the dashed box of **Figure 1** and is structured as follows:

Figure 1: Methodology for coming up with a Blueprint



Section 2: Electricity market modelling

Here we outline our process for assessing the economics that drive market dynamics. We include some of the key design choices within the market modelling.

Section 3: Power system modelling

Here we outline our process for assessing the physics of the electricity system to make sure the system is stable and reliable.

Section 4: Resiliency

Here we outline our approach to assessing resiliency benefits of the transmission network.

Section 5: Cost benefit assessment

Here we provide an overview of our cost benefit assessment, outline the guiding principles and key decision points. Our intention is to seek external specialist advice on this work, to be completed and available in early 2026.

Regarding competition

Competition between businesses creates incentives for them to reduce their costs and prices, improve their service levels, develop new products, and provide greater value to their customers.

The overall size and interconnectedness of the transmission grid can impact the level of competition among grid connected generators. Relieving physical constraints within the transmission grid can improve competition among generators to supply a previously constrained region. In so doing, this will reduce inefficiencies and reduce the extent to which prices faced by consumers exceed those expected in a competitive market.

We commissioned Deloitte to identify a robust methodology for quantifying the competition benefits of transmission investments. They assessed a range of modelling approaches and recommended a forward-looking, agent-based simulation. Castalia, in a complementary report, proposed a simpler method to estimate the cost of market power and how it might change with new transmission.

These reports can be found on our website.

We intend to use the methodology proposed by Deloitte to quantify competition benefits of increased transmission investment in New Zealand. Deloitte was tasked with designing a forward-looking methodology that could account for strategic bidding, while also using transparent data inputs. After reviewing several game-theoretic and simulation-based approaches, Deloitte recommended an agent-based model using machine learning. This approach simulates how market participants learn and adapt their bidding strategies over time. It is more realistic and flexible than traditional models and better suited to capturing future changes in market dynamics.

Deloitte have recommended using the open source ASSUME platform, adjusted as necessary for the New Zealand context.

Section 6: Appendix

In our appendix we provide additional information on the tests we have done on our market modelling to capture the right level of detail around network constraints while balancing the burden of computational complexity and model run times.

Next steps

This document is a statement of our intent. It is not an obligation for us to follow a particular course of action. Several elements of our process have not been tested in detail, and we may find they are not ultimately practicable within our resource (time and budget) constraints.

We will aim to update this document if our process materially changes.

2.0 Electricity market modelling

2.1 Summary

Electricity market models are economic models of the electricity system which represent the least-cost build and dispatch of generation and demand response against a user-defined demand forecast and generation retirement schedule. In this section, we discuss these models and our rationale for adopting certain approaches. We use these models to calculate the total electricity system cost (total system cost) across a range of scenarios and network development plans. Generation, energy storage, and transmission are co-optimised in our approach. The total system cost feeds directly into the cost benefit assessment that determines our grid blueprint.

We expect that this 'least cost' approach provides a reasonable starting point to assess what a competitive market would deliver. The New Zealand electricity market design is based on security-constrained economic dispatch using market offers submitted by participants. Under a competitive market, offers will approach short-run marginal cost (SRMC). So, assuming the market is competitive, a SRMC-based economic dispatch is a reasonable approximation. As discussed in Section 2.5, we also consider other factors such as capacity and energy adequacy to augment this least-cost view and to ensure the modelled expansion plan is suitable for investment testing. Sometimes it is necessary to iterate from these generation expansion plans to ensure suitability of these key metrics.

Our market model features rich detail around the generation dispatch, such as transmission constraints; the intermittency of renewable generation; variance and uncertainty in future hydro inflows, and operational constraints for physical plants and hydro reservoirs. This means our analysis can sufficiently consider the economic value of transmission in a highly renewable future.

Section 2.2 details our investigation into model design decisions around simplified network representations.

Section 2.3 details our inputs and model design decisions relating to generation expansion modelling.

Section 2.4 details our security-constrained generation dispatch model.

Section 2.5 details additional factors beyond least-cost optimisation, including generation revenue and resource adequacy.

Furthermore, we have tested several representations of the transmission network in the market models and quantified the cost of constraints on the existing network. There is a trade-off between the representation of network constraints and computational run times. We have found workable network representations which constrain transfer between regions but ignore intraregional constraints. Details of these tests are provided in the Appendix.

2.2 Network representation for market modelling

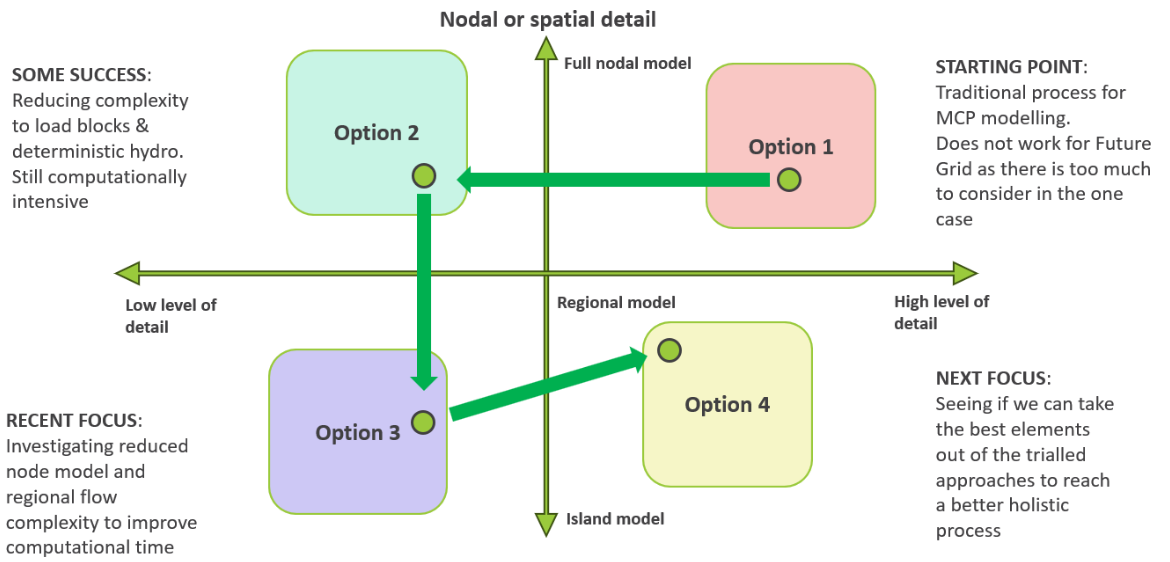
2.2.1 Model design decisions

The New Zealand electricity market sets prices every half-hour for nearly 300 nodes around the country. Price separation between the nodes is set by losses and network congestion on the grid[1]. If the nodes are 'electrically close' (meaning power flows between the nodes have low impedance) and transmission limits are high, then it is reasonable from a market perspective to combine the nodes into a single 'modelled' node.

Using this logic in our market model, we have considered a reduced-nodal network of the national transmission network. Doing so reduces the computational complexity and improves model run times. We do not use a reduced-nodal network in the power system model due to the risk of losing visibility over security issues.

We have considered a range of options within the market modelling approach. These options broadly fit into the four option categories illustrated in **Figure 2** and explained in more detail below. The vertical axis in **Figure 2** represents the level of spatial detail, whereas the horizontal axis represents the level of other detail (such as the use of load blocks, hydro dispatch algorithm, number of hydro/weather sequences, etc.).

Figure 2: Market modelling approach overview



[1] Price separation can also occur between Benmore and Haywards when the high voltage direct current (HVDC) is setting the risk in the reserves market.

Option 1: Traditionally for our large investment investigation projects or major capital projects (MCP) we use a full nodal model with a high level of simulation detail. The MCP process is typically focused on a single need across a small (localised) part of the grid. It takes up to two years of investigation to complete. This option is not suitable for the Te Kanapu programme where we are looking across the grid more broadly and we need to manage our level of detail more carefully.

Option 2: Full network model. Here we looked at keeping the full nodal detail in the market model but reducing some of the simulation and input assumptions, such as larger time gaps for load block models and using a deterministic hydrology input for the generation expansion model. This was still quite computationally intensive resulting in long run times. This would not be ideal for our work where a lot of iteration and simulations will be necessary.

Option 3: Pipes interconnector model. Here we investigated a reduced node pipes modal representation of the New Zealand transmission network, focusing on grouped regions and region-to-region flows between adjacent regions. This was represented as non-physical pipes between regions. This gave us the biggest reduction in computational time. However, we found that we were missing some information.

Option 4: **Boundary circuit model.** This option takes the best impacts and changes from all the approaches and created a hybrid boundary circuit model option. It applies constraints at a regional level, but uses the full nodal representation to assess flows, rather than non-physical pipes. This allows us to have accurate circuit power flow sharing between nodes and regions while also still reducing the computational time.

While we continue to test the models, Option 4 provides the combined benefits from Options 2 and 3 while still managing computational time and turnaround.

Any of these models could be used in the assessment of power system options development at different stages of the analysis based on the outputs required and the turnaround time.

2.2.2 Reduced node regional market model

For the reduced node market model approach, three versions were investigated. These are shown in **Figure 3** which depicts the interface between the regions as non-physical interconnector pipes.

These regions are relevant to Options 3 and 4 discussed above. Even though Option 4 uses full nodal detail to calculate flows, the regional boundary definition determines which transmission circuits we must monitor and apply group constraints to.

Figure 3: Regional market model representation and regional interfaces

Version 1: Based of the 13 regions in the Transmission Planning Report[2] that Transpower publishes annually. The circuits that cross between regions in the full nodal power systems model with this boundary definition are mainly core grid backbone circuits. Not many regional flow constraints were captured as these are relatively high-capacity circuits. It does not capture the regional transmission networks that come off the grid backbone.

Version 2: Here we added more regional networks that are known areas of high load growth. These include regions such as Queenstown, Tauranga, Edendale and Valley Spur. These regions have constrained amount of capacity into the region for supply. By modelling these regions, we capture the constraints of getting power in and out of them.

Version 3: This version adds more regions to a total of 39. Additional regions serve to break down any larger regions and ensure we have constraint equations spread across the whole network. The aim here was to help with the generation expansion buildout so there is a sensible amount of generation that is built in the model. We do not expect a large amount of generation in the metro areas of Auckland or Wellington so we can apply more constraints to these regions.

2.2.3 Our proposed approach

We will use **Version 3 (39 regions)** of the Regional nodal model, combined with **Option 4 (Boundary circuit model)** in the market model. This combination allows for greater accuracy around power flow sharing across circuits while keeping run-times reasonable. Option 4 also facilitates an easier mapping between the market and power system models.

Further details behind our rationale are provided in the Appendix.

2.3 Generation and transmission expansion modelling

2.3.1 Purpose, inputs and outputs

The purpose of expansion planning is to determine the addition and removal of generation and transmission capacity over a study horizon. Capacity expansion models consider the various trade-offs between investing (or not) in different technologies and locations, including wind, solar, geothermal, battery storage or grid. The models have the objective of minimising the total system cost; therefore, we consider the solution to be an optimal or least-cost expansion plan.

Key inputs into this modelling are:

- the stack of generation projects which can be included in the expansion plan, and their cost to build and operate (see *2025 Generation Stack Report*)
- the transmission options (along with costs) which can be included in the expansion plan (see *Transmission Expansion and Upgrade Options. Te Kanapu Technical Approach)*

[2] Transmission Planning | Transpower

- a demand scenario and other scenario assumptions (see *A Future Grid Blueprint for Aotearoa Consultation 2: Potential Scenarios*)
- details around the operational constraints in the electricity system

In the application of this methodology, we will determine unique expansions plans for different scenarios and different transmission options. We intend to solve the generation capacity expansion for an assumed network development plan. By testing many different network development plans, we can explore a broad solution space of generation and transmission. This will yield a co-optimised generation and transmission plan.

The outputs from our expansion plan models are:

- a build schedule of new generation
- the total and annualised capital cost of new generation and transmission
- the approximate operating costs of the electricity system

2.3.2 Approach to expansion planning

2.3.2.1 Solution strategy

The objective function of our capacity expansion models is to minimise the total system cost across the study horizon (e.g. to solve for the lowest cost supply of electricity). Total system costs are a combination of:

- the capital and fixed operating costs of future generation and transmission
- the costs to operate the electricity system (fuel, carbon, and variable operating and maintenance costs, deficit cost, and modelled penalties)

Expansion models are difficult to solve and often require heuristic simplifications to make them tractable. One well established technique involves the use of a solution algorithm which applies an iterative approach to solving the optimisation problem with repetition of the following stages until a satisfactory convergence is achieved i.e. the difference in the total cost between successive iterations falls below a pre-defined threshold, indicating that an optimal or near-optimal solution have been found. Steps are:

1. An investment module determines a candidate expansion plan.
2. An operational policy is determined, and the dispatch of the electricity system is simulated using this expansion plan.
3. The operating costs from this simulation inform the determination of a subsequent candidate expansion plan.

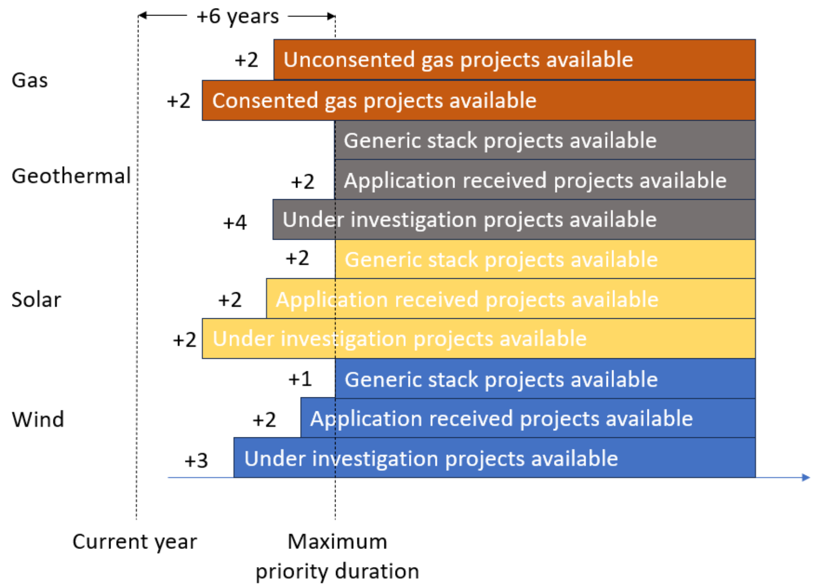
The operational problem (step 2 above) is performed using the same model as for generation dispatch simulations (described in Section 2.4), with some simplifications to ensure that the model can provide a solution in a reasonable time.

The capacity expansion plan optimisation problem can be partitioned into rolling horizons of several years and then solved in sequential stages. This both reduces the complexity of the optimisation problem, reducing solve times, and is a proxy for how the market might invest with limited foresight of the future. Alternatively, the optimisation problem can be solved in a single stage.

To align expansion plans with our expectations of what the market could deliver in the short-term, we initially constrain generation build to projects which developers have committed to, and to those projects which are in advanced stages of Transpower's connection pipeline.

Figure 4 illustrates the build timing restrictions. Additionally, we initially constrain the annual capacity additions to ensure that the model cannot move unrealistically quickly to a cost-optimal position.

Figure 4: Build timing restrictions applied in the generation expansion plan, based on the status of projects in the Transpower queue



2.3.2.2 Generation stack

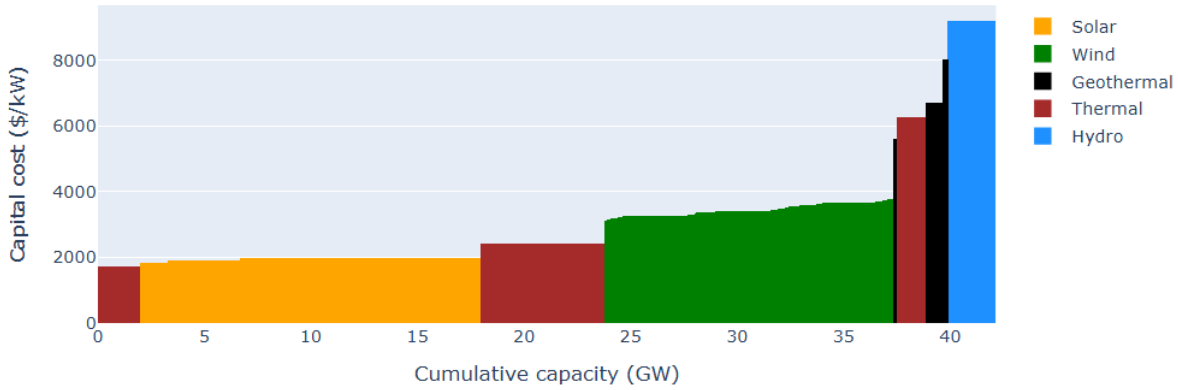
The generation stack is a database of potential generation projects which could be developed in the future. The stack is a key input into our generation expansion plan modelling and stack projects are considered by the model as candidates for development.

Our generation stack has recently been revised to align with project information in the public domain and to ensure costs are provided on a consistent basis. This revision provides project level costs and capacities for known wind and solar farms; for other generation technologies typical costs are given. For geothermal, thermal and hydro projects we use the 2020 Ministry of Business, Innovation and Employment (MBIE) stack reports for information[3] on project size and location. Generally, it is assumed that costs reduce over time and cost are provided out to 2060 for low, base, and high-cost scenarios.

[3] 2020 Thermal generation stack update report, Hydro generation stack update for large-scale plant. Future Geothermal Generation Stack

Figure 5 shows the generation stack of candidate projects. This image excludes speculative technologies which have higher, more uncertain, costs.

Figure 5: Generation stack of candidate projects with overnight capital costs in 2025 dollar values



Our generation stack includes the following level of detail for generation projects:

- the project capacity (MW)
- a connection bus on the transmission network
- an overnight capital cost of the project ($/kWac)[4]
- fixed operating and maintenance costs ($/kW/year)
- variable operating costs ($/MWh)
- heat rates (GJ/GWh) for thermal projects
- emission rates for geothermal projects
- a renewable resource for wind and solar projects
- other operational characteristics

There are many unique generation projects included in this stack, however many of them have similar characteristics. Where projects of the same type have equivalent costs and are located at the same place, we aggregate them. This reduces the number of options the model needs to consider and reduces the degeneracy[5] of the optimisation problem, reducing solve times.

The expansion planning problem for generation is also relaxed to allow for linear capacity additions as opposed to integer builds. This means the model can add fractions off a project, rather than having a project in its entirety. This significantly reduces the computation complexity of the optimisation problem.

2.3.2.3 Transmission expansion and upgrade options

Transpower's *Transmission Expansion and Upgrade Options* document outlines the set of enhancement options that will be considered for the transmission network. The cost and capacity of these will be represented in the expansion plan model. The network development plan will be an exogenous assumption, rather than something that is determined in the model optimisation.

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[4] This cost should encompass all component, construction, land costs and network connection costs. The figure excludes any financing costs.

[5] Degeneracy in optimisation problems is the occurrence of multiple solutions that are physically distinct but give the same value of the objective function.

We will test different transmission plans for each potential future scenario and explore the trade-off between transmission investment and total system cost. This will allow us to determine a transmission expansion plan which minimises total system costs. What we judge to be committed transmission enhancements will be included in all transmission plans (e.g. approved MCPs).

As discussed in section 2.2, we have different options that can be applied for representing the transmission network. The representation of transmission options in the expansion plan model differs for these representations:

For the pipes model:

- the network is represented as pipes which connect regions
- all potential future transmission options are either pipes which replace existing pipes, or new pipes if they connect regions which were not previously connected
- these pipe options all have a cost associated with them and create a change to the transfer limit
- if the build option is forced, then the revised pipe limits become active in the operational model

For the boundary circuits and full nodal model:

- all potential transmission options are represented as new or replacement circuits
- these have a capacity and impedance defined in the operational model, and a cost in the expansion plan model
- if the transmission build option is forced then the circuits become active in the operational model
- a revised boundary transfer limit, or other circuit pair constraint is applied through a circuit sum constraint in the operational model

More explanation around the implementation of these network representation models is provided in Section 2.2.

2.3.2.4 Generation retirements

Over the study horizon it is necessary to consider the retirement of existing and future generation.

We assume that all existing and future solar, hydro and geothermal plants will still be operable until 2050, so we don't consider their aged-based retirement. However, we do need to consider aged-based retirements for existing and future utility batteries[6]. These will be retired automatically in the model and a replacement plant will then be built by the model if it is economic to do so.

For wind generation we assume a 30-year lifetime and so we expect some existing wind generation to retire before the end of the modelling horizon. At this point, a replacement project will become available which the model can build if it is economic to do so. This replacement project is assumed to be at the same site and at a discounted capital cost to other available projects. This discount reflects the savings from the reuse of existing site infrastructure, such as turbine footings or grid connections.

[6] Utility batteries have a lifetime estimate of 15-years.

This economic repowering approach is preferable to exogenous assumptions around the timing of repowering and capacity uplifts which can lead to lumpy generation expansion plans with poor revenue adequacy.

The end-of-life for existing thermal plants (e.g. gas, coal, diesel) will also fall within the study horizon. However, determining the retirement date of existing thermal plants can be complicated due to the following:

- Midlife refurbishment, which are a go/no-go decision for generation investment. For example, the e3p (unit 5) plant at Huntly could continue to operate until 2057 with refurbishment in 2027. If this refurbishment does not go ahead then the plant is likely to close in the 2030s[7].
- The potential for extensions of operation life. For example, it is thought that with further investment the Huntly Rankine units could continue to operate until 2040[8]. This is significantly beyond the design life of the plant.

Rather than allowing the model to determine an economic retirement endogenously, we will exogenously specify a retirement schedule for existing thermal projects on a scenario basis. The retirement date may be determined iteratively by considering plant refurbishment dates, monitoring the revenue adequacy of plant to determine if it is failing to cover its fixed maintenance costs, and considering the adequacy of firm capacity available in the expansion plan.

2.3.2.5 Committed generation

Generation projects judged to be committed by developers will be modelled as exogenous build in the generation expansion model. This ensures that the initial modelled build is consistent with market developments. We will look for indication of a final investment decision to judge whether a project is committed.

2.3.2.6 Consumer energy resources

Rooftop solar and household batteries are included in the generation expansion model. These are represented through:

- exogenous (forced) build based on scenario assumptions around their prevalence
- candidate projects which the model can develop if it is economic to do so. Because the capital cost of rooftop solar and household batteries is higher than that of utility scale projects, it is anticipated that this endogenous build will occur only in cases of high grid constraint

[7] 2020 Thermal generation stack update report
[8] Genesis_huntly_firming_options.pdf

2.4 Generation dispatch modelling

Generation dispatch models are used to:

- determine an operating policy for hydro reservoirs
- simulate the security-constrained dispatch of generation

A generation expansion plan is an input to a generation dispatch model.

The operating policy considers the optimisation of hydro generation storage decisions. Depending on the algorithm applied, this can be either through:

- the calculation of water values for hydro reservoirs with the cost assigned to water considering the opportunity cost of storing water to generate in the future, versus generating now, or
- a set of storage targets for a given sequence of reservoir inflows.

This determination considers the uncertainty around future inflows (e.g. optimal policy for storing water considering that the future could be dry or wet) as well as the state of the market in the future (e.g. demand and supply balance). This makes it a stochastic optimisation problem in nature.

A stochastic dispatch model SDDP is an example of an algorithm that can be used to determine water values. It does this by walking forwards and backwards through the study horizon exploring possible hydro inflows and storage decisions to determine an optimal water storage policy. This policy is intended to minimise system dispatch costs.

The operating policy becomes an input into a simulation of generation dispatch. Compared with the policy calculation, a higher level of system detail is applied in the simulation. This includes temporal resolution and operating constraints for generation. The simulation occurs for synthetic hydro scenarios or actual historical inflow scenarios.

In summary, generation dispatch models are used to determine the least cost dispatch of assumed generation to meet demand, considering the following:

- uncertainty of future hydro inflows and availability of hydro storage
- renewable intermittency
- constraints around operation of plant
- transmission network constraints
- constraints around fuel supply
- other factors

Total operational costs are a key output from generation dispatch modelling. These include fuel and carbon costs, variable operating and maintenance costs, deficit cost, and reserve payments. Once combined with generation and transmission capital and fixed costs, these give the total electricity system costs.

It should be noted that our dispatch models assume short-run marginal cost (SRMC) offers for plants as opposed to competitive offers. For the purposes of this methodology, we consider that SRMC-based offers are adequate. Modelling of competitive offers will be covered in a separate report on competition modelling, refer to the Deloitte report: *Quantifying Competition Benefits of Transmission Investment. Methodology Selection.*

2.4.1 Approach to dispatch modelling for different technology

2.4.1.1 Hydro generation

Hydro generation has no fuel costs. Optimising the use of this limited resource is at the heart of stochastic optimisation techniques used to calculate the opportunity cost of using this water in storage. SDDP is an algorithm that is often used for this. The approach considers the available storage along with the uncertainty of future inflows and then determines an optimal policy for the use of water in storage, striking a balance between running out of water and spilling.

This stochastic optimisation process is iterative and repeats backwards and forward passes through the study horizon to determine a water storage policy for each stage. This is known as the SDDP policy. We calculate a weekly stage policy; this means that for any generator with storage there is a set of water values for different levels of storage applicable across the week. The water values can be a poor approximation of market offers where pricing may escalate at peak times and risk aversion in the market can lead to pre-emptive storage conservation[9], however there is a trade-off with computational run times.

Hydro generation is represented in the dispatch model with a topology that includes rivers and canals, generation plant and storage reservoirs. There is considerable detail in the representation of the Waitaki, Waikato and Clutha River chains. A full description of the configuration of hydro generation can be found in the Transmission Pricing Methodology (TPM) TPM Assumptions book. We use a record of historical inflows as an input to the model[10]. The hydrological data is used to produce a statistical model which can generate new hydro inflow sequences for simulations. Alternatively, the historical inflows can be used directly for future inflows.

In the dispatch model, storage reservoirs can store water between weekly stages, whereas the head pond for run-of-river schemes manages small scale storage. Much of the New Zealand hydro is essentially run-of-river, however the storage of head ponds yields considerable flexibility within a week.

It is necessary to specify outflow and a lower operating range as constraints for hydro generation and reservoirs. The model solution must either abide by these constraints, or an economic penalty is paid. Storage and flow constraints are based on a range of information including resource consents.

2.4.1.2 Thermal generation

Thermal generation covers natural gas, coal, diesel and biomass. It is characterised by high running costs when compared with renewable and hydro generation[11], and therefore its use is minimised in the least cost dispatch. We represent existing and future thermal generation in the dispatch model including combined cycle gas turbines (CCGTs), open cycle gas turbines (OCGTs), Rankine and reciprocating engine plants.

For existing CCGT and Rankine units we assume a stage commitment. This means that the plant must generate for the entire week if it is operating, although it can flex between maximum and

[9] Basing thermal offers on short-run marginal costs is another simplification which can lead to a disconnect between modelled hydro water values and offers observed in the market.

[10] Electricity Authority - EMI (market statistics and tools)

[11] Accepting that storage driven hydro running costs are determined by opportunity costs which in most cases are driven by avoiding thermal costs, so they are not independent.

minimum generation levels. This commitment reflects real world technical and operational constraints for these plants, where there is significant startup time from cold and they must then run for days to make generating economically worthwhile.

Thermal generation plants are configured with multiple fuel options and the model selects the cheapest available. Rankine units can consume natural gas, coal or wood pellets, OCGTs can consume natural gas and diesel. CCGTs can be fuelled only by natural gas.

Fuels are specified in terms of a unit cost, emissions factor and availability. The operating cost of generation is determined from the fuel cost, emissions factor, emissions price, heat rate, and variable operating and maintenance cost.

The deliverability and flexibility of natural gas supply is also reflected through the specification of an annual and weekly availability. The annual availability can reduce over time, consistent with our scenario assumptions around future natural gas availability (including the potential for LNG import). The in-year availability includes some seasonal shape to reflect that supply can be moved from summer to winter using storage fields.

The unavailability of thermal generation due to planned or unplanned outages is specified with an outage factor. The plant capacity is derated by this amount to reflect the average availability.

There are several cogeneration plants represented in generation dispatch model for which we assume a fixed generation profile which varies week-to-week. These are not represented as dispatchable plants because their electricity generation is determined by the production profile for the industry they provide heat for.

Table 1: Thermal generation technology and operating assumptions

Technology	Operating assumptions
Combined cycle gas turbine	Fuel option of natural gas Weekly operation Availability of 93%
Rankine units	Fuel options of natural gas, coal and wood pellets Weekly operation Availability of 78%
Open cycle gas turbine	Fuel options of natural gas and diesel Flexible dispatch Availability of 97%
Reciprocating engine	Fuel options of natural gas and diesel Flexible dispatch Availability of 95%

2.4.1.3 Geothermal generation

Geothermal generation has relatively low operational costs and runs as constant generation/baseload in the generation dispatch model. Most costs are upfront capex and, once constructed, it is economically rational to run the plant continuously. The upfront cost and ongoing fixed costs are assumed to cover steam field development.

There are no fuel costs for geothermal, however emissions of CO_2 and methane comprise a variable cost component as carbon is priced through the New Zealand Emissions Trading Scheme. The emission intensity of geothermal varies widely across existing fields depending on location, age and operational details. We set the emission intensity for existing fields to values reported by operators[12].

The emission's cost of geothermal generation is calculated in the generation dispatch model as the product of the assumed carbon price and field intensity. However, with the plants configured as baseload there is no option to turn down generation to avoid this cost. This inflexible operating profile is consistent with technical constraints for geothermal plants.

Future geothermal generation projects in our generation stack are in the Central North Island and Northland. We are aware of the potential of deep geothermal resource however this is not included in our stack as it is likely to be more expensive than conventional geothermal projects.

A recent trend by geothermal developers has been to build binary plants rather than large steam condensing turbines. For this plant type, reinjection of non-condensing gases appears very achievable, and we assume 90% reinjection at all sites. However, we note some uncertainty around the permanence of this sequestration as New Zealand's geology is not conducive to mineralisation.

Table 2: Geothermal generation technology and operating assumptions

Technology	Operating assumptions
Binary plant	Availability of 95% Reinjection of 90% of non-condensing gases Fixed generation output
Flash plant	Availability of 95% No reinjection of non-condensing gases Fixed generation output

2.4.1.4 Wind and solar

Renewable generation is characterised by low, or zero, operating costs and is utilised fully in a least cost dispatch. During periods of oversupply there are periods of spill or curtailment, and a small associated economic penalty.

We model renewable generation from existing and future wind and solar PV, including both utility scale projects and rooftop generation. Rooftop is aggregated to a regional level.

For each renewable project a resource is specified. This resource is a generation profile associated with the generation which reflects the intermittency and seasonality of the resource and how this is transformed by the generation technology (e.g. accounting for panel tracking for solar). We use PSR's Time Series Lab to generate synthetic renewable profiles[13] which are scaled to align with generation capacity factors determined using high-resolution wind modelling approaches[14].

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[12] https://www.nzgeothermal.org.nz/downloads/2025-07-29-co2-group.pdf

[13] Time Series Lab

[14] These regional capacity factors are reported in the 2020 Wind Generation Stack update

Table 3: Wind and solar generation technology and operating assumptions

Technology	Operating assumptions
Utility scale solar	North facing panels with single axis tracking Panels oversized by 30% System losses of 10%
Residential solar	Fixed axis north facing panels at 30deg tilt Panels oversized by 30% System losses of 10%
Wind	4 MW turbine size

2.4.1.5 Batteries and other types of energy storage systems

Batteries in the generation dispatch model are operated to shift energy between times of relative scarcity and surplus (e.g. for arbitrage) to minimise the total dispatch cost. They can also contribute to providing system reserve. We model both residential and utility scale batteries.

A battery is defined in terms of its capacity, storage duration and charge/discharge efficiency. We model battery energy storage systems (BESS) with two-hour and 10-hour storage durations and assume an 85% round trip efficiency.

Sufficient temporal resolution is required for the operation of BESS to be captured in the generation dispatch model. For example, the use of load blocks can wash out renewable intermittency and result in unrealistically low utilisation of BESS.

Table 4: Battery technology and operating assumptions

Technology	Operating assumptions
Utility scale batteries	2-hour and 10-hour storage duration Round trip efficiency of 85% Discharge rate
Household batteries	2-hour and 10-hour storage duration Round trip efficiency of 85%

2.4.1.6 Losses

Losses on the transmission network typically account for 3% of historical annual generation. This is a significant additional load which needs to be accounted for in this analysis.

Our approach is to escalate island loads based on historical system losses[15]. This is an approximation as losses depend on the power flow through the transmission network and future network losses are likely to differ to historical losses. However, including a calculation of losses in the dispatch model significantly increases computational time and would not be practical here.

We will estimate actual alternating current (AC) losses for different transmission options in a post-processing stage based on the power flow and circuit impedances. The cost of losses can then be estimated from the SRMC in the dispatch model. An adjustment is then made to the total system cost based on whether the losses are higher or lower than those assumed in the escalated loads.

[15] It may be possible to model losses explicitly for the pipes nodal model.

For the direct current (DC) network the dispatch model will directly include losses. We apply a piecewise function which approximates the parabolic losses observed on the high voltage direct current (HVDC). More information on this can be found in the TPM Assumptions book.

2.4.1.7 Instantaneous reserves

In the electricity market, instantaneous reserves are provided by standby generation which can compensate for an unexpected event and ensure supply is maintained. The reserve requirement is determined by the largest operating unit; typically a large thermal generator or a pole of the HVDC.

The requirement for reserves and providers of reserves is included in the generation dispatch model. The reserve requirement is set by the need to compensate for the individual outage of nominated backed plants, and specified backing plants can contribute to meeting this requirement. The model then co-optimises the dispatch of generation to provide energy to meet demand ensuring that standby generation is available to provide reserves for generating units.

We model sustained instantaneous reserves (SIR), which comprise only half of the instantaneous reserve market. Fast instantaneous reserves (FIR) are also procured to provide faster response cover for the same failure event as SIR. Other than interruptible load, there is considerable overlap between generation which provides FIR and SIR, so we consider it appropriate to consider only SIR in our modelling. The sharing of reserves between the North and South Island is ignored.

The backed units for the North and South Island which set the reserve requirements are summarised in **Table 5**. Of the existing generators, Tauhara 2a operates at 157MW as baseload[16] and is assumed to provide a floor for North Island reserve requirements through the study horizon. We ignore reserve requirements to cover the unplanned outage of any smaller generating units as the consequence of such is less than Tauhara failing.

Table 5: Reserve configuration in the dispatch model

Generators and circuits which require backing	Closed-cycle gas turbine units Rankine units Pole 2 and pole 3 of the HVDC Manapouri Tauhara
Backing generator groups	Open-cycle gas turbine generators Reciprocating generation Utility batteries Some hydro generation

Similarly for the South Island, we assume the generation from a single Manapouri generation unit (e.g. one turbine) sets the floor for reserve requirements. We do not model reserve requirements to back any other South Island generation.

A set of backing generators which can provide reserves has been defined in the generation dispatch model. This set comprises of applicable thermal and hydro generation, interruptible load

[16] We derate Tauhara by 10% below its nameplate capacity of 174MW to reflect the average unavailability due to outages.

and utility batteries, considering existing and future plant. The configuration requires the specification of an offer price and maximum capacity for every reserve provider.

2.4.1.8 Deficit

In our generation dispatch modelling, deficit will typically occur during peak demand periods, where there is not enough generation to meet peak demand, and during dry inflow periods where there is not enough energy to meet winter demand. Generally, the total amount of deficit is a very small proportion of the total amount of demand served to consumers. It occurs infrequently and for short periods of time.

We assume that the cost of deficit is defined by four incrementally increasing ‘tranches’, exemplified in **Table 6**. Each tranche is for a given amount of deficit, expressed as a percentage of island demand. The first three tranches are intended to represent voluntary demand response measures, such as retailers controlling hot water cylinder demand. The last high-value tranche is intended to represent forced curtailment of load (i.e., not supplying electricity), as could occur in a grid emergency.

Table 6: Example of deficit cost tranches (in 2021 NZD)

Deficit cost as a proportion of island demand	Cost
First 5% of demand	$ 600/MWh
Between 5% and 10% of demand	$ 800/MWh
Between 10% and 15%	$ 2,000/MWh
Greater than 15% of demand	$ 10,000 /MWh

2.4.1.9 Temporal resolution

A configuration option in the generation dispatch models is the resolution at which chronological data is represented. The demand scenarios and renewable resource profiles are available in hourly resolution. Representing this level of detail requires consideration of shorter time horizons, for example simulating every fifth year.

It is necessary in the expansion plan model to reduce the temporal detail to make the problem tractable. Typical approaches for reducing temporal detail are:

- Load block approximation where the demand profile is digitised across weeks into representative blocks of varying duration. Although this approach accurately represents the shape of demand, it can wash out variation in renewable generation (e.g. wind generation gets averages across blocks).
- Typical days which capture the daily variation in the demand shape in hourly detail but assume the same shape across days. It is possible to sample different renewable generation profiles for each typical day, and in this way ignore the averaging which occurs for load blocks.

2.5 Other factors beyond least-cost optimisation

2.5.1 Revenue adequacy

We assess the revenue adequacy of generation build from our expansion plans. For generation to be revenue adequate, its revenue must equal or exceed its annualised capital costs and annual fixed operations and maintenance costs. Annualised capital costs are a constant annual payment which reflects a project's overnight capital and financing costs.

The solution from the generation expansion plan models should, in theory, be revenue adequate based on the least-cost objective. However, we find in practice that the build from the expansion plan models may not be revenue adequate. This could result from the simplifications applied to the operational problem in the expansion plan model, and end-of-horizon effects. Our experience[17] is that there tends to be a slight overbuild of renewables and under build of thermal peakers and utility batteries[18].

We apply an adjustment process to the raw expansions from the expansion plan model to make them acceptably revenue adequate. At a high level this process is to shift the timing of capacity additions which has the effect of increasing or decreasing the prices (and hence revenue). If at any given time, projects being built are not revenue adequate, then we delay some of the build that was occurring at this time. By reducing the amount of low-cost generation, more expensive generation will be dispatched to meet demand (or deficit could occur) which increases prices. Similarly, if projects are earning too much, then build is brought forward which suppresses prices.

The adjustment process respects the overall sequence of generation in the raw expansion plan. However, projects built within the same year can be spread across multiple years in the adjusted expansion plan. In this process the worst performing projects will be delayed before better performing projects and vice versa.

We have developed an algorithm which applies these adjustments. At a high level, we complete the following steps:

1. Simulate the dispatch or a raw expansion plan from expansion plan model and calculate the annual revenue adequacy of generation.
2. In years where the revenue adequacy of plants is low, then delay build in this year.
3. In years where the revenue adequacy of plants is high, then bring forward project build into this year.

This is an iterative process which fine tunes build shifts to smooth revenues and prices between years. Our experience tends to be that build shifts are relatively minor.

Additionally, we will evaluate the revenue adequacy of existing thermal and geothermal generation. Although the capital costs are sunk, there may be significant ongoing fixed operating costs that need to be covered. If these costs are not being covered by generation revenue, then the closure of the plant in the expansion plan model may be warranted.

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[17] Based on the PSR suite of market modelling software.
[18] This can be mitigated to an extent using more detailed daily sampling in the expansion model.

2.5.2 Generation adequacy assessment

Typically, when a least-cost expansion plan is simulated in a dispatch model, periods of non-supply occur. These periods of energy deficit result when there is insufficient generation available to meet demand; this could be a capacity shortage or an energy shortage. This energy deficit has an economic cost associated with it.

The shortfall in generation can result from:

1. it not being economic to build generation for all eventualities. For example, having generation available to supply during the very worst dry year will mean that capacity is not utilised, or spill occurs in most years.
2. simplifications to the operational problem applied in the expansion plan model may mean that the shortage is not well represented. For example, if the there is any aggregation of temporal detail, then this masks renewable intermittency. Then when the expansion plan is assessed in the dispatch model with greater renewable variation then a capacity shortage may be observed during periods of low wind.

The revenue adequacy adjustments can correct for some of the latter and the overall level of supply can be informed by a system reliability specification. For example, AEMO's Integrated System Plan applies a Reliability Standard which requires that at least 99.998**%** of forecast customer demand to be met each financial year in each region[19].

We will ensure a reasonable level of generation adequacy by either:

- applying firm energy/capacity constraints in the expansion plan model to ensure that enough firm generation exists in the system. Firm energy/capacity contributions can be defined for different generation types. For example, it could be assumed that 90% of thermal, geothermal and BESS[20] is firm capacity, and only a fraction of wind generation,
- adjusting the generation build manually in a post processing stage like the revenue adequacy adjustments, or
- defining thermal build exogenously to ensure there is sufficient generation capacity. For example, the generation expansion plans tend to not sufficiently compensate for assumed thermal retirements. The replacement thermal following a thermal retirement could be directly specified as an input for model.

Typical generator availability will also be considered to ensure that the system performance is robust to plant outages.

This approach may result in a level of generation above what is economically supported by payments in an energy only market e.g. there is a missing money problem. We assume that this capacity is paid for by the market in some other way, such as the creation of a capacity market, or the same outcome through bilateral contracts hedging risk.

[19] isp-methodology-june-2025.pdf

[20] The 'firm' contribution of BESS is sensitive to the generation mix.

3.0 Power system modelling

3.1 Summary

Power system models capture a detailed view of the physics and engineering associated with an electricity system. Power system modelling is a critical step in assessing the viability and impact of any network development plan. Market model conditions and snapshots are imported and analysed to ensure they are meeting power system security criteria as defined by the Electricity Industry Participation Code (the Code). This section goes into how the market model snapshots are imported into the power systems analysis tool, and the process of checking and validating that the mapping and migration of inputs has been done accurately.

The section details how the thermal, steady-state, static voltage stability and dynamic limits are defined and assessed; the process of creating region-to-region transfer limits, and how they will be fed back to the market model as constraint equations. The calculations gradually increase in detail as we refine and narrow down the set of network development plans we consider.

This model uses the full Transpower-owned transmission network system with 220, 110 and 66 kV networks modelled with lumped distribution and customer loads at the 33 and 11 kV voltage level. You can find representations of our network on the website Maps and GIS Data | Transpower.

3.2 Planning assumptions and criteria

3.2.1 Security criteria

The Code dictates that for core grid assets, n-1 security is required. This criteria will be applied for the thermal limit, voltage band limits, static voltage stability limit, and dynamic stability limit analysis. This is a minimum level of security that we are required to provide. Where it is economic to provide a higher level of security, for example to serve very large or high-value loads, we will.

3.2.2 System conditions

The electricity market modelling (refer section 2) produces system conditions for the reduced-nodal network model in the modelling horizon. A subset of these results will then be imported and translated into the full power system model for power system analysis which will include:

- AC load flow modelling
    - steady-state voltage limits
    - thermal limits
    - static voltage stability limits (PV)
- dynamic stability limits

System conditions are selected based on how problematic the given condition is likely to be on the transmission network. For example, considerations that would make a system condition suitable for power system engineering analysis include:

- high power flows on the reduced-nodal network model, particularly on known transmission bottlenecks
- low levels of synchronous generation
- peak and trough loads
- peak generation conditions by fuel type and region, particularly where the generation has been built by the generation expansion model

3.2.3 Contingencies

For this analysis we will only test a subset of credible contingent events[21]. This includes:

- a single transmission circuit interruption
- a single inter-connecting transformer interruption
- the failure or removal from operational service of a single shunt unit:
    - reactive support device
    - largest generator unit in the region

3.2.4 Thermal limits

The analysis assumes that transmission lines are limited to 100% of their respective winter and summer thermal ratings. The analysis will not use any short-term overload or 15-minute offload time transmission line capabilities. This provides a margin to allow for small changes such as minute-to-minute fluctuations in load that occur naturally in power system, or changes in voltage setpoints.

For this analysis, transmission lines with variable line ratings (VLRs) (ratings that fluctuate depending on the time of year, hour of day and ambient temperature), will have the minimum line thermal ratings applied for the respective season.

Supply transformer thermal capacity limits will not be calculated. If they are overloaded, this will be resolved by adding parallel units to supply the load at n-security level.

The investments we consider and compare to upgrade transmission capacity are covered in our *Transmission Expansion and Upgrade Options* report.

3.2.5 Steady-state static voltage stability limits

The analysis uses the voltage criteria that at all 220 kV and 110 kV buses, voltage is maintained between 0.9 per unit (p.u.) and 1.1 p.u. for both normal operating conditions and for a contingent event unless there is an existing Local Quality Agreement (LQA) or Wider Voltage Agreement (WVA) for the transmission bus.

Supply bus voltages will be excluded from this analysis.

The steady-state voltage stability limit is used to identify the maximum demand (load limit) of a region to ensure voltage stability. This limit depends on the performance of generating units, on-load tap changers, reactive limits for dynamic reactive support (such as SVCs, STATCOMs, and synchronous condenser), load power factor and capacitor banks in service.

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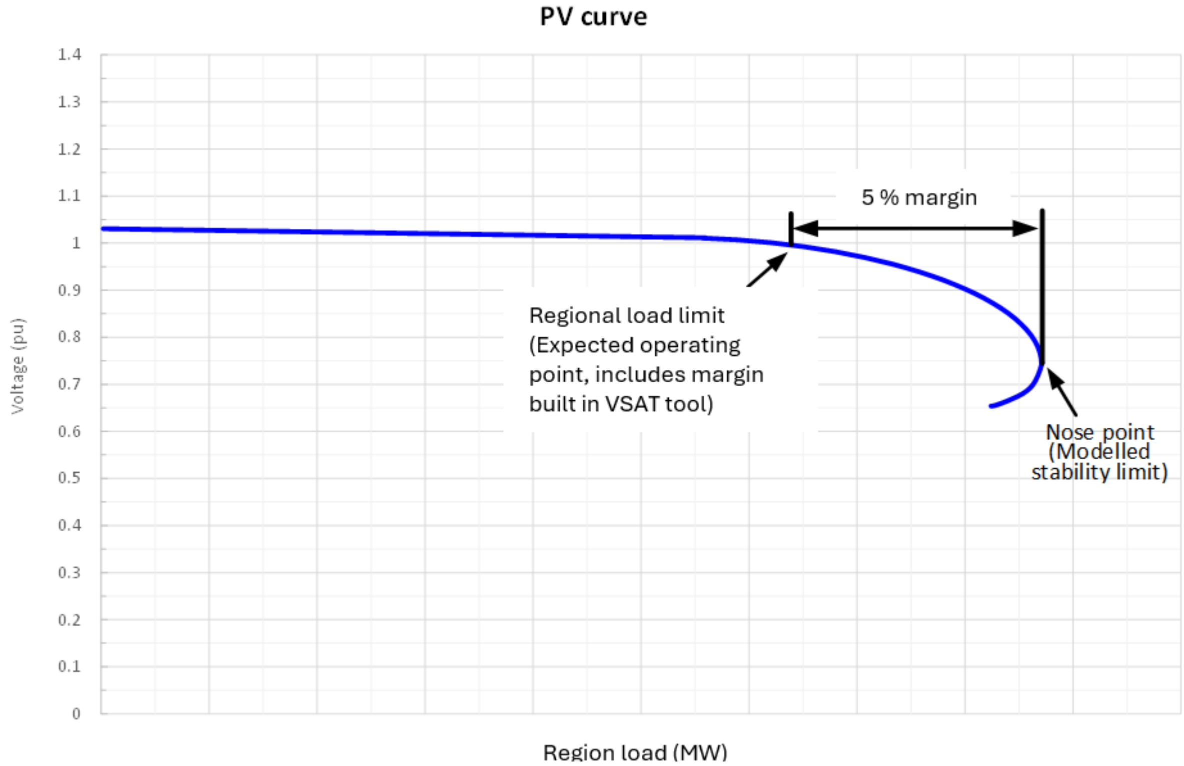
[21] Electricity_Industry_Participation_Code_-_1_April_2025.pdf Page 74

Static voltage limits will be calculated using the PV limit methodology. The following assumptions are used:

- Our approach is to utilise new and/or existing shunt caps to improve the static voltage stability limit while limiting the pre-contingency output of dynamic voltage regulation devices to within +- 20% of their continuous reactive power limits.
- All dynamic voltage regulation devices (e.g. generators, SVCs, STATCOMs, synchronous condensers, HVDC, etc) are within their continuous reactive power limits post-contingency.
- The voltage is within the acceptable operating range.

Figure 6: PV curve example plot



For PV analysis, the region load is increased in steps while monitoring voltage levels at buses. The characteristics of a PV curve (illustrated in **Figure 6**) are:

- near the 'nose' of the PV curve, voltage drops rapidly with a small increase in MW transfer,
- the PV nose point is the maximum power transfer into a region and the load at PV nose sets the voltage stability limit, and
- operating near the voltage stability limit poses a risk of widespread voltage collapse. To ensure a satisfactory operating condition, a sufficient margin is necessary. A margin of 5% from the nose point is applied throughout the investigation, which includes an additional 5% margin built into the real-time System Operation VSAT tool.

The main investments to improve steady-state static voltage stability limits are shunt capacitors and STATCOMs.

New shunt capacitors will be the primary mode of injecting reactive power into the transmission network to improve static voltage stability limits during peak load periods. However, with the addition of more shunt capacitors, the transmission network becomes more compensated and must operate at an increased pre-contingency voltage plane to be above the stable nose-point. If the nose-point of the region of the network being tested is above 1.0 p.u. then STATCOMs will be used to help improve static voltage stability limits without over-compensating the transmission network.

3.2.6 Dynamic voltage stability limits

Transpower's transient voltage criteria are defined for:

- non-generator buses by Transpower's Grid Planning Guidelines
- generator buses (nearest HV bus to generators) by the requirements set out in the Code, clause 8.25A reliability standard for the New Zealand power transmission system

The overriding criteria is that the power system remains stable during and following a fault.

For generator buses the generator voltage fault ride through criteria in the Code clause 8.25A is applied. If only a single generator is connected to the bus and the fault is the loss of this single generator, then the criteria for a bus with no generators connected applies.

The voltage recovery criteria are determined by Transpower's Grid Planning Guidelines and the Electricity Authority's generator fault ride through criteria[22].

For major (220 kV and 110 kV) buses with no generators connected, Transpower's Grid Planning Guidelines recovery criteria is:

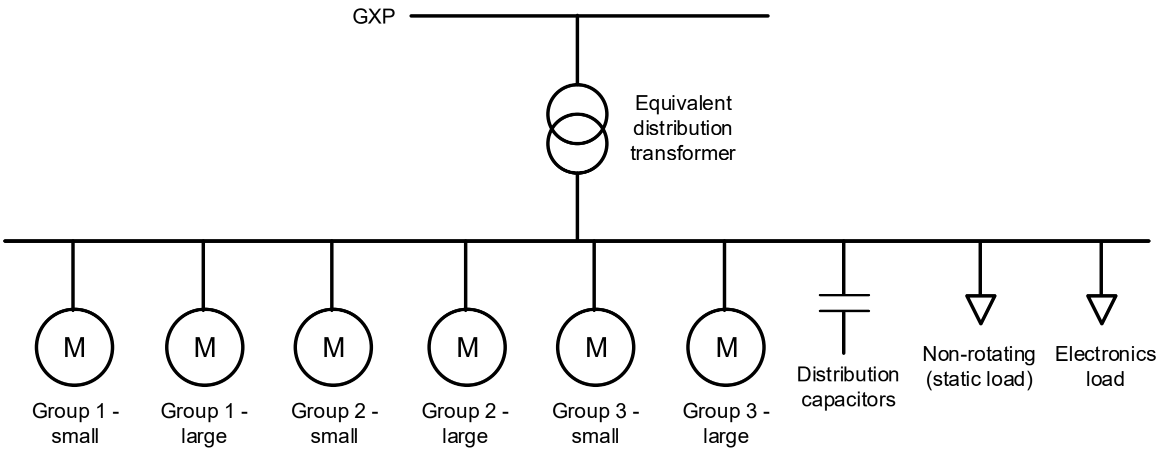
- voltage must be greater than 0.5 p.u. following a single credible contingency event which removes an item of equipment from service without a transmission system short circuit fault. For modelling purposes, all load is assumed to stay connected during and following the event
- voltage must recover to above 0.8 p.u. in less than 4 seconds and above 0.9 p.u. in less than 60 seconds following a credible contingency event
- voltage overshoot must be limited to below 1.3 p.u
- voltage overshoot must not be above 1.1 p.u. for more than 2 seconds

For the dynamic voltage stability analysis, information is required on the make-up of voltage-sensitive load in the region. The loads across the network are represented as dynamic load models. Transpower has surveyed regions of the network to get this information, and the dynamic load model overview is shown in **Figure 7** below. It consists of:

- induction motor load
- static "non-rotating" load
- electronics load
- known distribution capacitors

[22] Part 8—Common quality | Electricity Authority

Figure 7: Dynamic load model overview



We will use the latest load survey data for each region. For areas of the network where a survey hasn't been completed, we will use suitable planning assumptions to model the dynamic load behaviour and composition.

Additional STATCOMs will be used to provide dynamic reactive power compensation and voltage regulation into the transmission network to help it recover quickly from large faults or disturbances as peak load increases.

3.2.7 Generation dynamic models

Dynamic models of existing and possible future generators are required to determine if there are any dynamic instabilities. Existing generator models will be sourced from publicly available Root Mean Square (RMS) models released in the Electricity Authority's Electricity Market Information (EMI) dataset[23]. Assumptions around what models to use for future generators will need to be made as detailed information regarding future generation projects is not available.

Additionally, these models must be parameterised to account for various possible sizes of future plants. The following assumptions will be made based upon generation technology.

- New geothermal will be based upon the most recent generator models at Te Mihi and Tauhara B.
- New wind generation will be modelled using established[24] templates.
- New solar generation will be modelled using established templates.
- New BESS will be modelled using equivalent grid forming technology.
- New thermal generation will be modelled using insights from existing generation on the network and generic models.
- New hydro will be based upon IEEE generic models.
- Any other emerging generation technologies will be evaluated on a case-by-case basis.

[23] https://www.emi.ea.govt.nz/Wholesale/Datasets/Transmission/PowerSystemAnalysis
[24] See for example template models at https://www.wecc.org/

3.2.8 Angular stability limits

Angular stability is a synchronous machine's ability to remain synchronised under normal operating conditions and to regain synchronism after a disturbance. Transient rotor angle stability (TRAS) is critical for the System Operator to ensure the stable operation of the grid. Loss of synchronism – sometimes referred to as 'out of step' or 'pole slipping' for synchronised machines can severely damage synchronous generators. It can also lead to power system instability, voltage fluctuation, loss of other generators and system collapse. Rotor angle stability analysis is done by running dynamic simulations and monitoring generator rotor angles across the system.

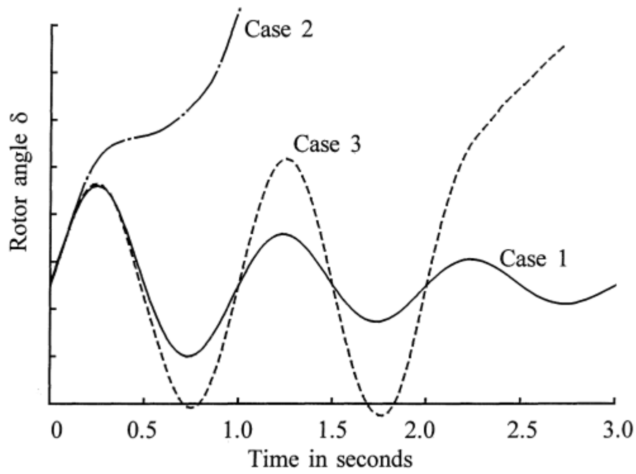
Rotor angle plots following system disturbances are shown below. The plot **Figure 8** shows:

Case 1: A stable, positively damped response

Case 2: A first swing unstable response

Case 3: A negatively damped unstable response

Figure 8: Rotor angle over time plot



The transient stability analysis focuses on rotor angle stability, of two types:

- **First swing stability:** when the system is unstable following the first rotor angle swing after fault clearance, instability shown in case 2.
- **Rotor angle oscillation stability:** when the system is either negatively damped or poorly damped, instability shown in case 3.

For this analysis, only first swing stability resulting from bolted three phase faults will be assessed. The fault clearance times will follow what is outlined with the protection standards of Part 12 of the Code and Planning Guidelines.

As the grid evolves over time with changing generation mix, new inter-region flows and upgraded transmission infrastructure, it is important to assess whether the proposed grid maintains transient rotor angle stability. This will be particularly important where there are large generation hubs sending power through long interfaces, or multiple generation hubs connected via weak tie lines.

3.2.9 Committed transmission projects

All committed projects will be included as part of the base case model.

Our threshold for committed Transpower projects includes:

- funding approved
- delivery business case signed
- design completed

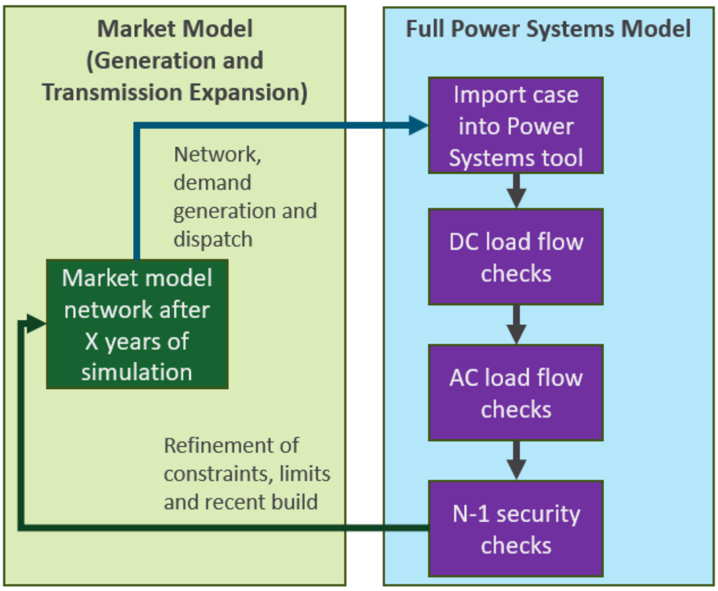
For customer funded projects it includes:

- Transpower works agreement signed
- final investment decision approved
- funding secured
- resource consents approved
- delivery business case signed

3.3 Power system checks on market modelling cases

During, or at the end of, the market model simulation, we can intervene and perform power system checks to the system that is being tested. This is to ensure that the models align, the generation dispatch is reasonable, and the network meets power system security requirements.

Figure 9: Model feedback loop



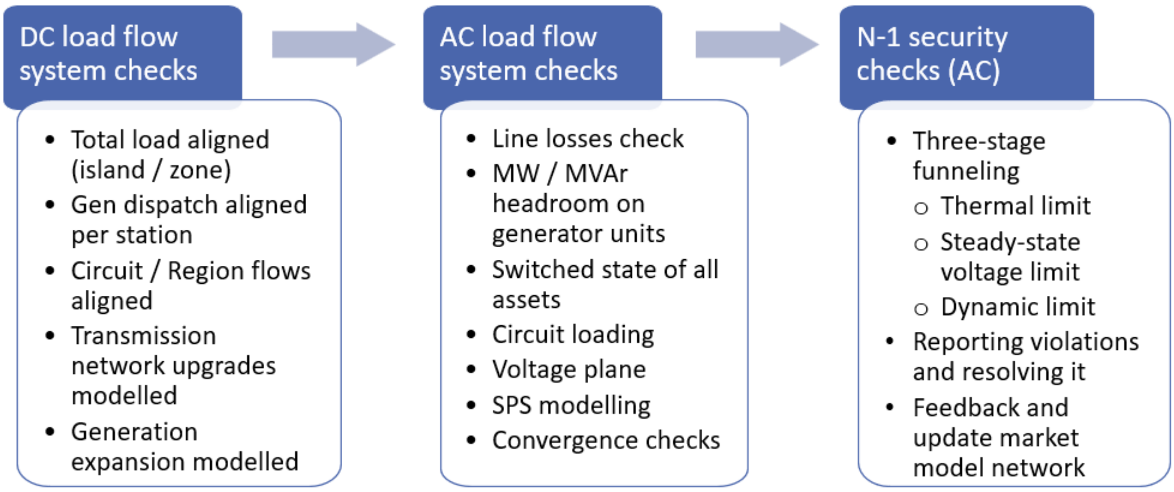
We can import the market model simulated network including demand, generation, dispatch and transmission upgrades into the Power Systems analysis software as shown in **Figure 9**. We will be testing a wide range of market model snapshots and system states, and feedback refinements in updated constraint equations, limits and possible build options to resolve any n-1 issues.

Different network conditions can be the result of:

- the transmission upgrades that were chosen to be built
- the new generation that has been added
- generation dispatch
- demand scenarios

Taking the market model network inputs into the power systems analysis tool requires three checks to ensure that it is correctly modelled and mapped and that the load flow is solving in a valid manner. The overview of this process is shown in **Figure 10**.

Figure 10: Power system modelling checks



DC load-flow checks

The first step is to import the model and run DC load-flow checks. This is to check the mapping of the load and generation dispatch has been done accurately alongside the circuit active power flows and substation import/exports. This step should be closely aligned to the market model simulations. The new transmission network upgrades and generation expansion produced by the market model also needs to be correctly reflected in the power systems model.

AC load-flow system checks

After we ensure the DC load-flow checks have been passed then we progress to AC load-flow system checks. This stage incorporates reactive power flows, system/line losses and voltage planes. We must ensure that the assets are not overly loaded and that there is enough reactive power in the system for AC load-flow convergence pre-contingency with high voltage and low voltage supply buses being in the correct operating voltage range. This part of the power system network validation will provide us with how many additional shunt reactive devices would be required for that specific market model snapshot to aid in system convergence and voltage support. The numbers of additional shunt devices to maintain voltage profile are an input into the final cost benefit analysis.

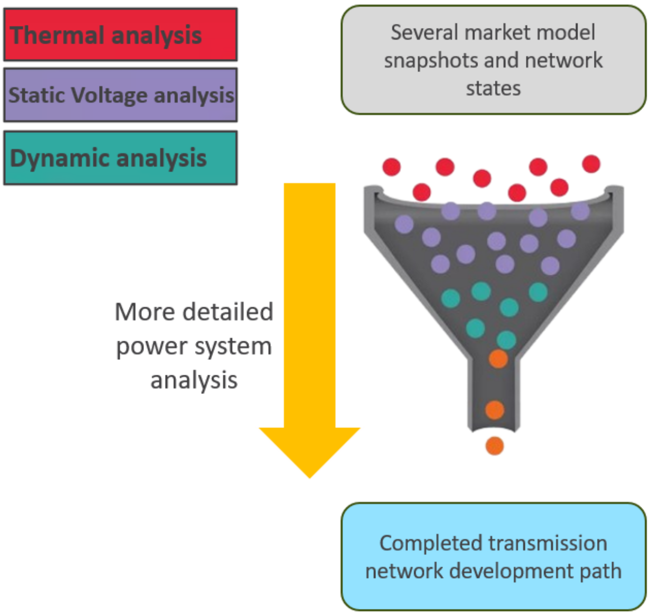
n-1 security checks

Once the AC load-flow system checks and convergence for peak load periods has been validated we can go through the power system n-1 security checks of the thermal, steady-state static voltage and dynamic limits.

We will be using a three-stage funneling approach for our market model case analysis of transmission development paths as shown in **Figure 11**. Each subsequent stage increases in complexity and fewer system conditions are used. The three stages involve looking at and resolving any n-1:

1. circuit thermal issues
2. steady-state static voltage issues
3. dynamic stability issues

Figure 11: Three-stage funnelling approach for power systems analysis



This funneling approach ensures that we can assess as many cases and system conditions as possible, by layering the three types of limit analysis based on complexity and discarding transmission development options when they don't pass any stage or aren't comparable from a cost and power systems security standpoint over other cases for a given scenario tested. This is to avoid over-analysing a large amount of network states coming in from the market model so we can look at the widest view of scenarios and build options to pick up trends and effective transmission solutions.

At this step the number and location of dynamic shunt devices (e.g. STATCOMs) to maintain dynamic stability is confirmed and this becomes an input into the final cost benefit assessment.

3.3.1 Calculation of regional transfer limits

Regional transfer limits are assessed based off the transmission network and any new upgrades that are included alongside regional demand growth and generation. The limits are based on n-1 thermal limit violations. These will be fed back into the market model as constraint equations so there are realistic flows across the grid during its economic simulation of new generation and transmission build, and generation dispatch. The limits will then be updated as there are transmission upgrades that improve region-to-region transfer capacity. The power systems limit analysis also helps refine the constraint equations that are fed into the market model. This is to ensure that the transmission grid is being built out to meet the power system security requirements while trying to optimise the cost of generation and transmission.

Figure 12: Waikato to Auckland regional transfer limit schematic

We have developed an algorithm to determine region-to-region flow limits between interfaces with circuits crossing between them. In the example shown in **Figure 12** we have Region 2 (the Waikato) exporting to Region 1 (Auckland). The power is sent north via eight, high capacity 220 kV circuits, being:

- Bombay-Huntly-1&2
- Ohinewai-Otahuhu-1&2
- Brownhill-Pakuranga-Whakamaru-1&2
- Otahuhu-Hautapu-Whakamaru-1&2

The region-to-region flow limits are assessed in DC load-flow simulations. The process is as follows:

1. Define all region and circuits that cross between regions, that have been identified as the eight crossing circuits alongside the Waikato and Auckland regional definitions and boundary.
2. Define and setup generation-to-region mapping for regional generation mix system conditions that get tested individually. In our example, Waikato has multiple generating stations with various fuel sources. These are thermal at Huntly, wind at Te Kowhai and the Waikato River hydro schemes. The individual exporting generation mix sensitivities tested are:
    a. Base case generation mix
    b. 20% or 80% hydro generation
    c. 20% or 80% thermal generation (excluding baseload geothermal generation)
    d. 20% or 80% wind generation
3. Define slack bus location(s) within exporting region. For this example, it is the 220 kV busses at Whakamaru, Huntly, Ohinewai, Hamilton.
4. Evenly scale up loads in the importing region being Auckland (excluding industrial load such as Glenbrook Steel Mill).
5. Test n-1 limit only for circuits that cross between the export and import region; the eight circuits that have been identified.
6. Once the limit is found, record the pre-contingency crossing circuit flow sum and the n-1 binding scenario. In this example it is which Waikato circuit contingency resulted in the binding overload of one of the eight crossing circuits that have been defined.
7. Loop over all generation mix sensitivities defined above for the same slack bus location.
8. Loop over all defined slack bus generator locations and generation mix sensitivities.

3.3.2 Defining constraint equations for the economic model

Constraint equations are required in the following cases:

- where circuits or transformers operate in parallel and an outage of one increases the loading on the other
- where there are stability constraints across several circuits or transformers between regions

Constraint equations describe the pre-contingent maximum loading of the two (or more) circuits or transformers in combination i.e. they limit these assets to their n-1 capacity.

The three separate pieces of power system engineering analysis (load flows, voltage stability, and transient stability) define a collection of constraint equations which are fed back into the market model.

3.3.2.1 Thermal constraint equations

The following is a format for a thermal constraint equation:

$$\mathbf{A \times monitored\ asset + B \times contingent\ asset \leq RHS}$$

where:

- monitored asset is the pre-contingency flow of the circuit or transformer that is being protected, in MW
- contingent asset is the pre-contingency flow of the circuit or transformer that trips out due to a contingency (an unplanned outage), in MW
- A is the multiplier on the steady state flow on the monitored asset. This is typically 1.0 for planning purposes
- B represents the fraction of the flow on the contingent asset that is transferred to the monitored asset during an outage on the contingent asset. B is also known as the distribution factor
- RHS is for circuits, this is the continuous rating of the monitored circuit in MVA[25]. For transformers, this is the 24-hour rating of the monitored transformer in MVA. Note there will be a summer and winter value

Another format of thermal constraint equation based of the region-to-region limits is that the pre-contingency flow sum of the specified regional crossing circuits between two regions is below a specified MW value based of the results from the process described in Section 3.3.1.

3.3.2.2 Voltage stability and angular stability constraint equations

For stability constraints there is no B (distribution factor) co-efficient. Therefore, the typical format for a stability constraint equation is:

$$\mathbf{monitored\ asset_1 + monitored\ asset_2 + \ldots \leq RHS}$$

[25] For use in a DC power flow the MVA ratings need to be converted to the equivalent MWs. However, in most cases using the MVA ratings within a DC power flow application, will provide a more conservative RHS as most of the network is operated at a voltage higher than 1.0 p.u.

4.0 Resiliency

4.1 Summary

Electricity users expect a continuous supply, with as few interruptions as possible and rapid recovery when interruptions do occur. The ability of transmission to provide this continuous supply is measured through factors of 'reliability' and 'resiliency'; two distinct but related concepts that address the grid's ability to provide continuous and stable power.

Reliability is focused on how the system performs under normal conditions, whereas resiliency is focused on how the system performs under abnormal conditions.

The key differences between reliability and resiliency are outlined below.

Table 7: Key differences between reliability and resiliency

Aspect	Reliability	Resiliency
Focus	Prevention of power outages under normal conditions.	Ability to recover and adapt to severe disruptions or extreme events.
Primary Concern	Ensuring consistent power supply without interruptions.	Ensuring the grid can bounce back from disruptions quickly.
Measurement	Metrics like outage frequency and duration.	Recovery speed, adaptive capacity, and backup systems.
Example	Maintaining power during everyday usage.	Restoring power quickly after a natural disaster or cyber-attack.

In this section we discuss elements we have considered in our work on resilience for the future grid blueprint, including costs and benefits.

The benefits of reliability and resiliency are based on avoiding costs due to lost productivity; lost revenue for businesses; spoilage of goods; inconvenience for customers; direct costs of restoring power and repairing damaged infrastructure; consumer compensation, and risks to public safety.

This section explains in detail how these benefits are calculated.

4.2 Risk assessment

In developing a future grid blueprint, we assess the risk of significant power supply interruptions[26]. The risk of an event is calculated as the probability of that event occurring multiplied by the consequence of that event. The total risk is the sum over independent event risks.

New Zealand has a range of risks that require consideration. These include volcanic activity, high corrosion zones, braided rivers, flood zones, earthquakes and tsunamis. Our analysis considers the risks that primarily impact the major transmission corridors between regions. Our future grid analysis does not consider risks to local supply and connection assets[27].

Given the impact that weather events can have on reliability and resilience, Transpower seeks to manage this by locating assets away from known natural hazards, building additional redundancy into the network, and diversifying the location of assets.

Back-up generation at homes and businesses also helps manage reliability and resilience, however, they can have a high running costs and not everyone will have them. Our calculations consider that some households and organisations will have backup generators.

4.2.1 Events and probabilities

We consider natural disasters and equipment fault as possible events that could cause a significant power supply interruption. Although other events such as terrorism, cyber-attack and human error exist, we consider the probabilities of such events are too speculative to include in our quantitative method. The probabilities of events are estimated using data from the following sources:

- for natural disasters, GNS Science and NIWA (now both Earth Sciences New Zealand) data
- for equipment fault, asset failure statistics (from national and international data)

These events generally have low probability but high consequence. They are often referred to as HILP events (high-impact, low-probability events).

4.2.2 Consequence

The consequence of an event is the cost that results from it. Generally, we consider two approaches to estimating these:

1. The direct cost to the electricity consumers who are directly affected by the interruption.
2. The broader cost to the economy due to the interruption.

In both approaches, the consequence is calculated by the unserved energy multiplied by the cost of unserved energy. Other costs include things such as direct asset repair or replacement costs, public

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[26] Our blueprint will support Transpower's Risk Management framework more broadly through managing key risks, including risk of not being able to find the skilled resources; risk of not having the right grid at the right place at the right time; reputational risk; and supply chain risk. However, the only risk that we assess in determining the Blueprint is the risk of significant power supply interruptions.

[27] These risks are considered in other more detailed work within Transpower.

health and safety costs, environmental costs and social costs. However, the economic costs of the interruption tend to dominate the equation, so our analysis focuses on these.

When considering the direct economic costs (approach 1), the cost of unserved energy is set using the Value of Lost Load[28] [29] (VoLL) inflated to 2025 dollars. When considering the broader economic costs (approach 2), the cost of unserved energy is calculated using a detailed model of the economy[30].

The unserved energy is calculated based on the location of the event and the assets that are taken out by the event. The unserved energy considers the post-event demand for electricity, as opposed to the regular demand for electricity. This means we consider the disruption the event may cause on the impacted communities.

4.3 Benefits assessment

The options considered in our analysis will, to varying degrees, reduce the risk of a significant power supply interruption by providing either:

- greater redundancy of supply into a region, or
- greater geographical diversity of line routes[31].

Other options to improve resiliency are possible but not covered within our analysis. Particularly, these include developing contingency plans, intentional islanding, and strategic stores of spare equipment that can be deployed in the event[32].

Resiliency benefits are assessed by comparing the risk between a case where a network development plan is implemented against the counter factual. The reduction in risk provided by the network development plan is the resiliency benefit.

[28] Value of Lost Load (VoLL) Study - June 2018.pdf
[29] PWC Estimating the Value of Lost Load.pdf
[30] An example of a potential model would be the MERIT tool: https://www.nzta.govt.nz/assets/Highways-Information-Portal/Technical-disciplines/Resilience/Resources-and-information/MERIT-primer-document.pdf
[31] Our Te Kanapu analysis only identifies regions between which greater transmission capacity may be needed. We do not determine specific details around line routes. However, if new lines between regions create diverse pathways for network flows, then this may carry reliability and resiliency benefits.
[32] These options to improve resiliency are considered in more detailed work within Transpower.

5.0 Cost benefit assessment

5.1 Summary

The cost benefit assessment (CBA) is where we compare the different total system costs across different network development plans and different scenarios. Ultimately, this comparison must yield a single preferred development plan which determines the final blueprint. We refer to this as the blueprint development plan.

This chapter outlines the key considerations, guiding principles, and some general details of our approach to the CBA. A more detailed description of our approach will be published in due course.

Our power system analysis assesses the physics and engineering of each development plan, in each scenario. Market modelling then assesses the cost of each development plan, in each scenario. Competition and resiliency costs are assessed once market modelling and power system analysis have converged.

The CBA takes these costs as inputs and determines:

- the optimal development plan for each scenario
- the Blueprint Development Plan, which balances the desire for an optimal development plan with the uncertainty of the future

5.2 Options, sets and network development plans

Different transmission expansion and upgrade options are outlined in our report *Transmission Expansion and Upgrade Options Report* (the report). Options are grouped into categories including upgrades to existing assets, new high voltage alternating current (HVAC) lines and new HVDC lines.

We discuss 'option sets' as a set of independent options taken from the report [33]. For example, an option set might include three options: an upgrade to circuits in the West Coast; a new line through Central North Island, and a new line north of Auckland.

Network development plans include an option set plus the assumed commissioning date of each option.

We need to limit our analysis to a workable number of network development plans. The first two network development plans we consider are:

1. The counterfactual which is a minimal set of network upgrades (see more below).
2. An unconstrained network. This is a fictitious network development plan where the transmission network is unconstrained.

[33] Options within an option set cannot be mutually exclusive.

These two provide an upper limit to the amount of network investment that may be justified and provide a heuristic approach to understand which parts of the network need additional capacity.

Using these two network development plans as a starting point, we use our experience in transmission planning to propose candidate network development plans, designed to relieve constraints and capture the benefits of the unconstrained network.

5.2.1 Defining the counterfactual

The counterfactual is defined using a network development plan made up of the existing transmission network plus all committed projects.

For Transpower projects, our threshold for committed includes:

- funding approved
- delivery business case signed
- design completed

For customer funded projects, our threshold for committed includes:

- Transpower works agreement signed
- final investment decision approved
- funding secured
- resource consents approved
- delivery business case signed

The counterfactual needs to consider a realistic level of service for electricity supply. If a lack of transmission network upgrades prevents this level of service being realistic, local generation capacity is assumed to be built downstream of the transmission constraint. This local generation raises the level of service to a realistic level.

The counterfactual may also require shunt elements (such as capacitor banks) to stabilise the power system. The additional cost of the local generation and shunt elements is included in the total system cost of the counterfactual.

5.3 Assessing the optimal network development plan for a given scenario

Within a given scenario, the optimal network development plan is the one with the lowest total system cost. We refer to this as the scenario-optimised network development plan.

5.3.1 Quantifying the total system cost

Total system cost is determined for each plan within each scenario. This is a net present value of costs accrued throughout the horizon.

Costs that are determined by the **market modelling** include generation capex; transmission (including series connected devices, such as series caps or series reactors); operating and maintenance; fuel; emissions, and deficit.

Costs that are determined by the **power system modelling** include the capital cost of shunt-connected devices (such as capacitor banks, synchronous condensers, SVCs and STATCOMs).

Costs that are determined by the **competition modelling**[34] include consumer surplus, producer surplus and deadweight loss.

Costs that are determined by the **resiliency assessment** include risk.

The total system cost is the sum of all these costs.

5.4 Determining the grid blueprint development plan

Finding the optimal network development plan across different scenarios is more challenging and it is unrealistic to expect that a single plan will be optimal across all scenarios.

Because it is unknown which scenario will ultimately eventuate, no single network development plan can be definitively called optimal.

Some commonly used approaches include 'maximising net benefit and minimising regret' (also called minimax). **Figure 13** provides a high-level illustration of the concept of regret.

[34] Economic surplus is not a cost; it is a benefit. However, a reduction in consumer surplus can be seen as a cost to consumers, and similarly for producer surplus. For a more detailed discussion of how we include competition effects in the cost benefit assessment, refer to the Deloitte report: *Quantifying Competition Benefits of Transmission Investment. Methodology Selection.*

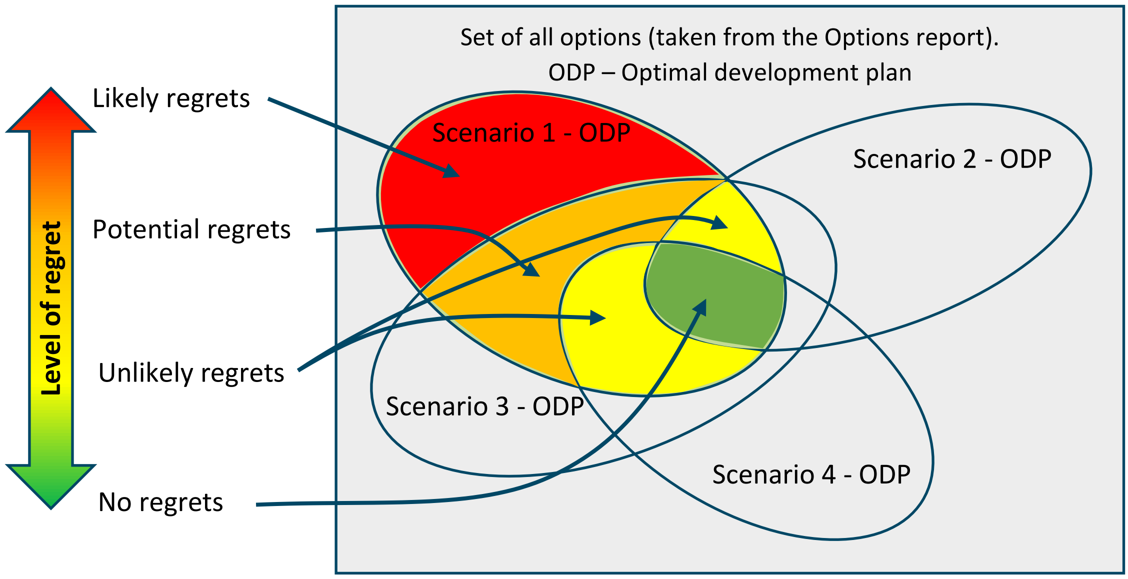
Different approaches can lead to different decisions. There is no best approach, it depends on an organisation's tolerance for risk. We are working with a specialist consultant to further refine our approach and will publish further detail in due course.

Key issues to address include selecting an approach to match industries' (including consumers') risk tolerance, considerations around scenario weighting and the use of sensitivities.

An important step in the process for determining the grid blueprint development plan involves considering the range of different scenario-optimised network development plans and deciding whether any additional plans need to be analysed (for example if a scenario-optimised network development plan was not assessed under a different scenario). Importantly, this step would propose plans that include additional preparatory or enabling work to provide greater optionality.

This will be discussed further in subsequent publications.

Figure 13: Illustrates the concept of regret when making decisions under uncertainty



6.0 Appendix

6.1 Trial runs with different network representations

As discussed in Section 2.2, we have developed multiple network representations which can be used in the market model with different levels of detail. We have considered:

- the full nodal model which includes the entire high voltage transmission network
- the pipes models where the network has been aggregated into regions
- a hybrid 'boundary circuit model' network configuration

This section describes the configuration of these network representations in the market model and some high-level testing.

6.1.1 Implementation and testing of the full nodal model

The full nodal model includes all buses, circuits and transformers in the high voltage transmission network.

The market model solves a DC/linear power flow model to determine the network circuit flows for a generation dispatch. This is computationally efficient and adds little overhead to the solution, however the consideration of network constraints can add significant computational time.

Network constraints can apply to both:

- individual circuit flows, ensuring that the dispatch does not exceed the rating of individual network elements, and
- sum of circuit flows (group constraints), allowing the dispatch to be restricted by security considerations.

The sum of circuit constraints can be used to directly represent contingent circuit outages and ensure that the dispatch is n-1 secure. This would be applied through a group constraint of the following form specified in Section 3.3.2.

It is possible to construct constraints which ensure n-1 dispatch across the entire network using this approach, however this requires many constraint equations to consider all contingency possibilities. We have found that there is a limit to the number of constraint equations which can be included in the dispatch model before the problem becomes intractable.

To manage this, the constraint equations can be filtered to ensure that only the most significant circuit combinations are included. For example, if the outage of a circuit has very little impact on other circuits, then this can be ignored.

We have conducted benchmark modelling to examine how the constraints of the existing transmission network can restrict future supply assuming demand growth[35]. We undertake

[35] This modelling is based on the Disruptive scenario for the HVDC Link Upgrade Programme MCP Benefits Modelling

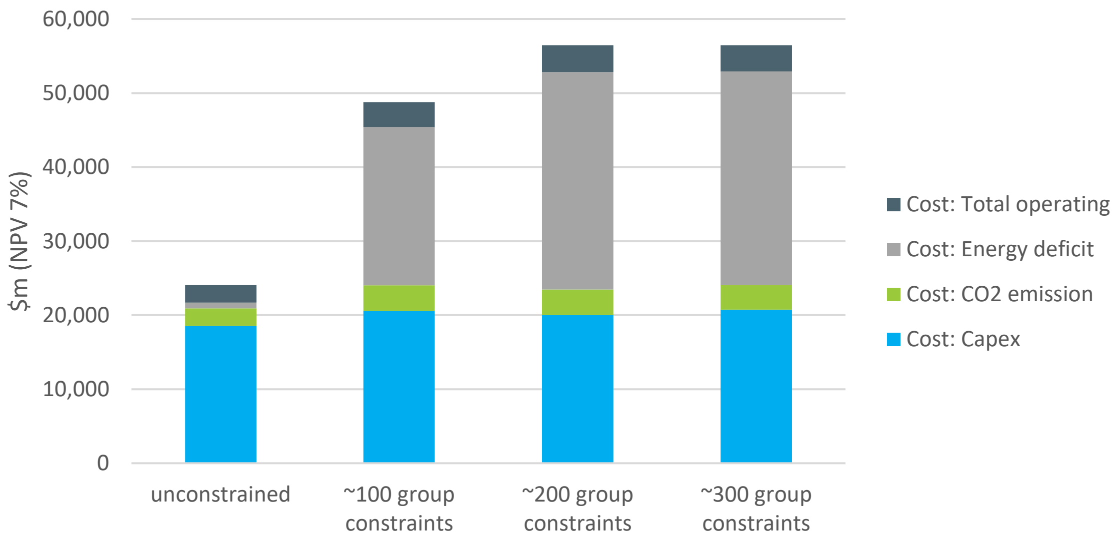
generation expansion modelling to allow new generation to be built and connect to the network, however the capacity of the network is fixed at current levels.

An initial set of approximately 100 constraint equations was prepared based on an 80% post-contingent loading threshold. That is, the circuit pair was only included as a constraint equation if the post-contingent power flow on the monitored circuit reached 80% of its limit. We tested this set of constraint equations in the models and then introduced additional group constraints based on circuit flows calculated. Additional circuit pairs were introduced as constraint equations for subsequent testing where the calculated post-contingent loading exceed the loaded circuit limit.

The results of this benchmarking are shown in **Figure 14**. This shows that the inclusion of network constraints increases total electricity system costs compared with an unconstrained network. This is due to increases in capital and thermal operating costs, and more significantly, deficit costs[36]. The cost increases reflect that the electricity supply is less efficient when there are network constraints with increases in spill and more use of thermal generation; and that constraints result in significant non-supply for parts of the network.

The inclusion of additional group constraints increases total system costs; however, we find that the increases plateau at around 200 group constraints. Further increasing the number of constraints does not result in an increase in operating costs, although we observe a significant increase in model run time.

Figure 14: The cost of constraints on the existing transmission network using the full nodal model



6.1.2 Implementation and testing of pipes interconnector model

For the pipes model, all nodal demand and generation is aggregated to a region and there is no underlying network detail in the market model. A consequence of this is that any constraints within the region are ignored and any regional generation can meet any load within the region. This can create supply opportunities which are not available in the full nodal model.

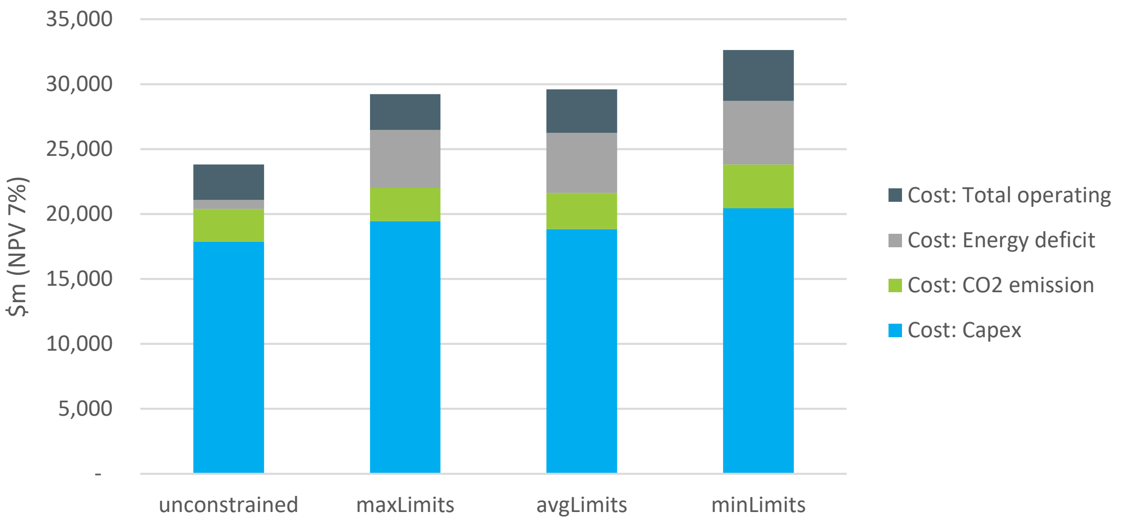
[36] The capital costs are determined using the expansion plan model, and the operating costs and deficit are from the generation dispatch model

There is no physical transmission network included in this model and the connections between regions are represented as interconnectors. The interconnector transfers are decision variables; this means that the model can essentially choose to send power down a pipe, rather than the transfer being determined by circuit characteristics. A result is that non-physical transfers can occur in network configurations where there are parallel pipes between regions.

Transfer limits are applied as constraints for each of the interconnectors and are included in the dispatch optimisation problem. These pipe transfer limits are pre-determined using the power system model, as described in Section 3.3.1. This means that there can be a disconnect between the system states assumed in the contingency analysis which determine the transfer limit, and the system states that the boundary circuit limit applies to in the market model. The minimum, maximum and average transfer limits reflect the transfer limit variance over different system conditions.

The total system costs for the pipes model are shown in **Figure 15**. The cost of constraints is highest when the minimum transfer limits are applied. The increase in deficit costs for the pipes model is significantly less than that observed in the full nodal model.

Figure 15: Cost of existing network constraints for the Pipes v3 model



The inclusion of additional pipes increases the computational time for the model. This is likely due to a combination of the inclusion of more decision variables in the optimisation problem and increasing constraints around interconnector transfer limits. However, the pipes model computational time is manageable in terms of application of this methodology.

6.1.3 Implementation and testing of the boundary circuit model

The boundary circuit model is a combination of the previous two approaches. The full nodal network is included in the market model. However, the dispatch constraints apply only to the boundary circuits between two regions. For example, the circuit flows between regions must satisfy the constraint equation:

$$P_A + P_B + P_C < \textit{boundary limit}$$

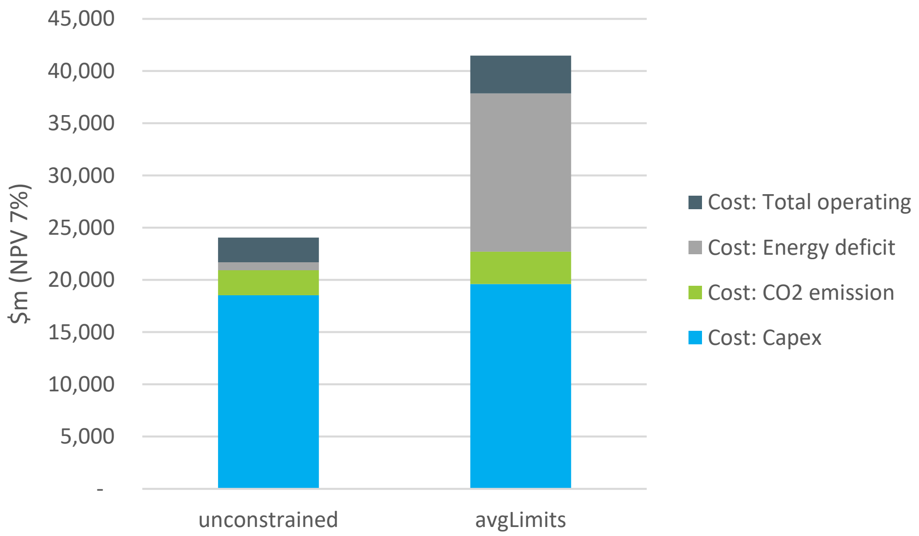
where P_A, P_B, P_C etc are circuit flows between regions with an applicable boundary limit.

Like the pipes interconnector model, with this representation the actual circuit contingency analysis occurs entirely in the power system model. However, the advantage of the boundary circuit model is that it still represents the detail of the transmission network which ensures the boundary flows are consistent with the physical characteristics of the underlying circuits.

The approach avoids the high number of contingency equations required by the full nodal model where group constraints are required for circuit pairs. The boundary circuit model can be configured with 46 circuit sum equations which is workable in terms of computational time.

The total system cost for the boundary circuits model is shown below in **Figure 16**. Significant network constraints are resolved for this model.

Figure 16: Cost of constraints for the boundary circuit model



We note that it may be possible to incorporate additional terms into a boundary circuit constraint equation to incorporate dependencies on regional load and generation. This would improve the alignment between the system states considered in the power system model, and those in the market model.

6.1.4 Comparison of network models

As outlined above, the majority of variance in the electricity system cost between the different network representations is due to deficit. Higher levels of deficit indicate that network constraints are resolved in the model to a greater extent. **Figure 17** compares the regional deficit for the different network model configurations.

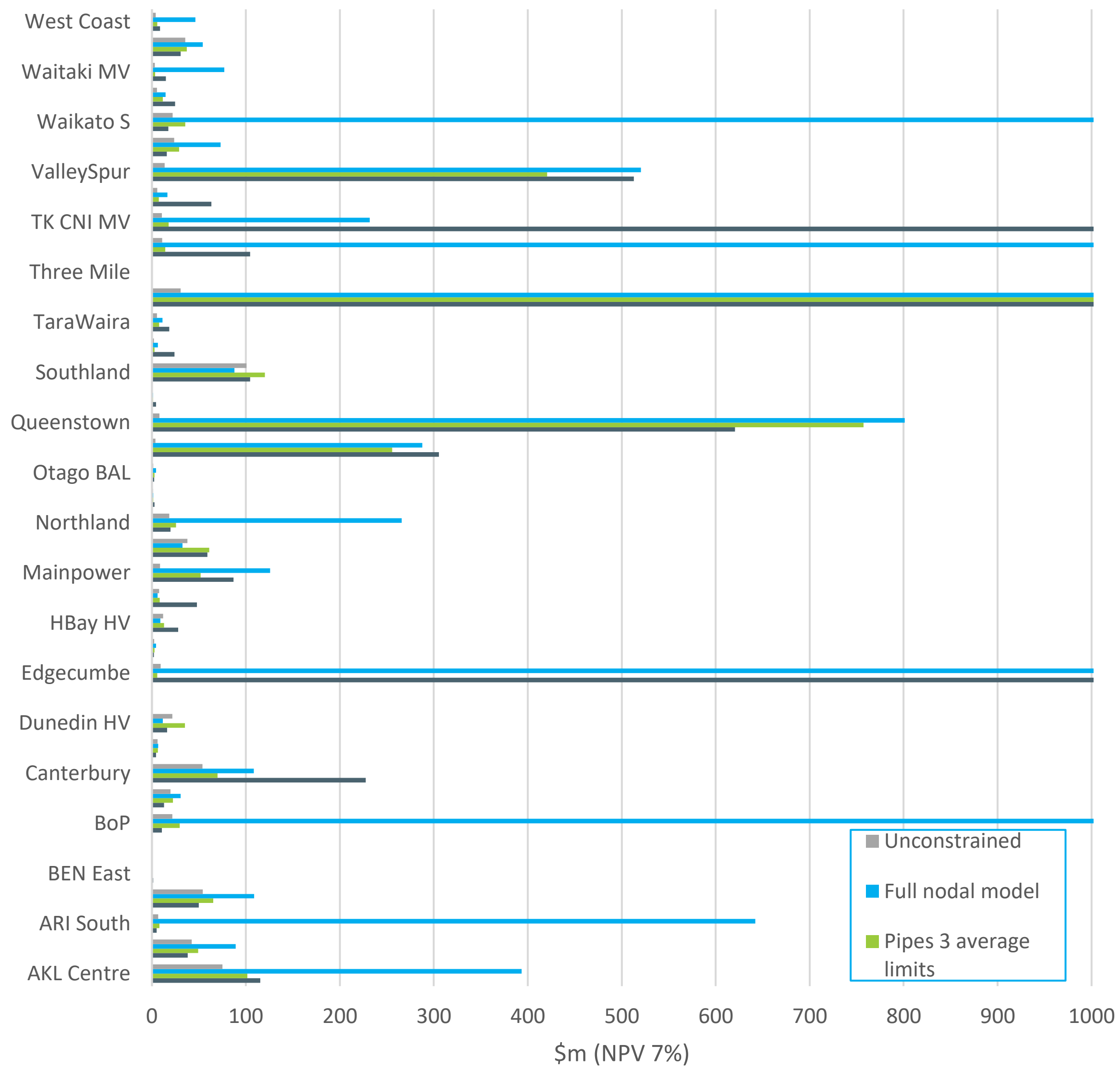
It shows that deficit costs are concentrated at specific network locations. The highest levels of deficit exist in the broader Bay of Plenty area including Edgecumbe and Tauranga[37]. The full nodal network model demonstrates the highest levels of deficit in these regions, followed by the boundary circuits model.

[37] Note that the investments approved in the Western Bay of Plenty MCP have not been included in these network models. These upgrades and other committed transmission projects will be included in the development of the grid blueprint, however for the purposes of testing this methodology, we do not consider it an issue that these upgrades are ignored.

The regional network models (pipes and boundary circuits) do not consider certain network constraints by design. Within region network constraints are ignored and so a reduction in deficit costs between the full nodal and regional models is expected. Timaru is an example of a region where the constrained circuits are entirely within the region. As the objective of the grid blueprint is primarily to address future needs of the grid backbone, it is acceptable for the model to not resolve isolated constraints which might apply to only a single grid exit point.

The selection of the network model is therefore a configuration choice which can be varied depending on the level of network representation required. The different network models could be applied at different stages of the grid blueprint analysis; as the regional models are considerably faster to solve[38], it would make sense to apply these during the expansion planning stage and apply different levels of network detail once the generation build has been resolved.

Figure 17: Regional deficit cost comparison between network models



Note: the axis is clipped at $1B.

[38] We observe that model solve times can be 5x less for the regional models

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