



Net Zero Grid Pathways

Scenario development
– EDGS 2019 variations consultation

December 2020

A short introduction to this consultation



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Purpose of this consultation

The purpose of this consultation is to seek feedback from interested parties on the draft Electricity Demand and Generation Scenarios (EDGS) 2019 variations we have developed for evaluating our Accessing Lower South Island Renewables (ALSIR) and Net Zero Grid Pathways (NZGP) projects.



Net Zero Grid Pathways

In *Whakamana i Te Mauri Hiko* we identified that the development of a long-term transmission system plan would promote least regrets decisions in delivering a pathway towards greater renewable electricity generation and electrification of the wider economy. We are calling this plan Net Zero Grid Pathways (NZGP).

The aim is to ensure investors have an integrated view of future power system investment needs – including opportunities for new renewable generation and distributed generation. Given the up to 10-year lead times for approving and consenting new transmission lines, generation investors need to know ahead of time that we are proactively planning transmission that will enable their generation.

Given the opportunity to utilise lower South Island renewable generation further north, resulting from the announcement of the pending closure of the Tiwai point aluminium smelter, we have reframed our approach to our NZGP work and will complete it in two phases.

In Phase One we will focus on development of the transmission system after the smelter's closure.

This phase is our Accessing Lower South Island Renewables (ALSIR) project. In Phase Two we will continue our analysis out to 2050 and complete our NZGP project.

A diagram showing the approximate timeline for phase one and two and the approximate timeframe into the future each project will cover is shown in Figure 1

Net Zero Grid Pathways

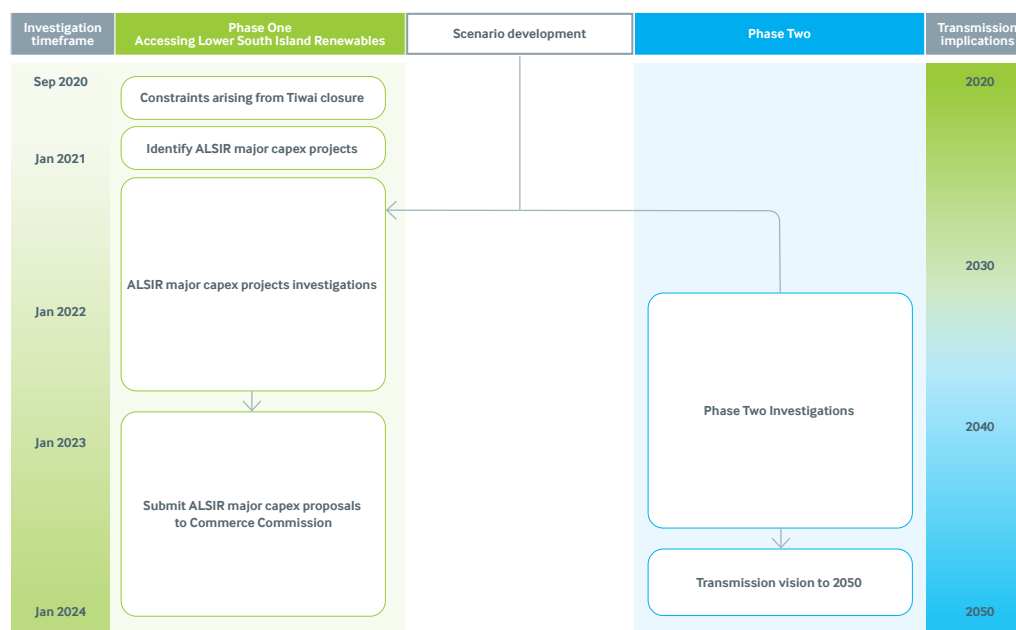


Figure 1: Outline of the NZGP project timeline and relationship between Phase one and two

Scenario development

In order to undertake the analysis required, we need to develop a common set of demand and generation scenarios. An outcome of our ALSIR investigation may be the development of major capex proposals for the Commerce Commission.

In order to recover the costs of investing in the grid, the Commerce Commission require that Transpower consider the Electricity Demand and Generation Scenarios (EDGS) developed and published by the Ministry of Business, Innovation and Employment (MBIE). In the time since the last release of the EDGS in July 2019, significant changes have occurred in the New Zealand electricity landscape, including the announcement about pending closure of the Tiwai smelter.

The Commerce Commission recognise that changes may occur which affect the suitability of the currently published EDGS for Transpower purposes and allow us to use “reasonable variations” of the EDGS in our analyses. As such, in order to start our investigations, we have been considering what are the “reasonable variations” we should consider as part of our investigations.

For this project, we engaged a panel of industry experts to help us review the existing EDGS and recommend any changes which may bring them up-to-date and make them suitable for both phases of our NZGP investigation. Our review includes the input variables to the EDGS and not the underlying stories behind each of the scenarios.

We are aware that MBIE are considering a data update of the July 2019 EDGS. We are also aware that the Climate Change Commission will be publishing draft carbon budgets and policy recommendations to the government on how to achieve net zero carbon by 2050, in February 2021. We also recognise there are still uncertainties regarding the nature of a smelter closure and its flow on effects across the electricity system and market. However, even with a delayed closure, the lead times for transmission investment to enable access to renewable generation is still on the critical path, and this enforces our need to review the EDGS now.

Making a submission



This consultation is open until 5:00pm, Friday, 26 February 2021.

Submissions should be emailed to demandforecasting.co.nz@transpower.co.nz using the heading “Draft EDGS 2019 variations consultation”.

Submitters may comment on any relevant aspect of our topic. We have asked some specific questions below and would welcome submissions on those questions, but all relevant comments are welcome.

Submissions will be posted on our website and be public. If any aspect of your submission is confidential, please advise us and we will not publish that part of the submission.

If there is any aspect of your submission that is confidential, please:

- clearly inform us of the sections you consider confidential and indicate why
- indicate whether we can share the confidential information with the Commerce Commission

Transparency is important in this process and we may not be able to rely on confidential information to justify an investment proposal.



EDGS 2019

On their website, MBIE explain that the purpose of the EDGS is to explore a range of hypothetical electricity supply and demand futures, considering different demographic, economic, policy and technology dimensions.

The EDGS are used in our major capital investment investigations. Transpower can recover the cost of investing in the grid by contracting with individual parties, but where multiple parties are involved (sometimes all electricity consumers in New Zealand), the negotiations involved would be impractical. Instead, the Commerce Commission effectively act as agents for those multiple parties and they require that we follow certain processes in order to recover our costs.

We undertake long-term planning to forecast the level of transmission services we should provide. Long-term planning is necessary because the assets we use to deliver our services are long-lived (20–80 years expected life) and the lead time to install new assets can be long (up to 10 years for a new transmission line).

When our forecasts predict we will need larger, or more, assets to provide the services consumers want¹, we consider enhancing the transmission grid.

If the expected cost of the enhancement exceeds \$20 million, the Commission prescribe the process we must use in order to recover the costs from our customers. The process is described in the Transpower Capital Expenditure Input Methodology (Capex IM)². It requires that we submit a Major Capex Proposal (MCP) to them, which is effectively a business case justifying the need for investment, the option we believe is most beneficial to consumers and the expected cost.

Because our investigations consider so far into the future, electricity supply and demand is very uncertain. We use scenarios to ensure we consider a plausible range of different futures and the Capex IM requires that we use the EDGS, or reasonable variations of those scenarios, when preparing MCPs.

The scenarios test the economic efficacy of potential investment options over a range of futures, so the scenarios need not be forecasts of the most likely future electricity supply and demand. Typically, the scenarios would include a central scenario which is thought to be most likely, but the other scenarios would be diverse in terms of the transmission grid that would be required to enable them. Regardless, the scenarios should be reasonable and not too extreme, or highly unlikely.

The Capex IM requires that we assign probabilities to each scenario and so scenarios included for transmission diversity, but which are less likely to occur, can be assigned a lower probability than more likely scenarios.

¹ As a result of load growth, new grid-connected generation, or to increase reliability of supply, for instance

² <https://comcom.govt.nz/regulated-industries/input-methodologies/transpower-ims>





The EDGS 2019 are fully described here, but in brief, consist of five scenarios which reflect future levels of electricity demand and generation out to 2050:

| | |
|-----------------------|--|
| Reference: | Current trends continue. The central theme of this scenario is that long-term historic trends continue, with minimal disruption. |
| Growth: | Accelerated economic growth. Higher immigration drives increased population growth, while policy and investment focus on priorities other than the energy sector. |
| Global: | International economic changes. New Zealand's economy is battered by international trends, leaving little room for growth or innovation. |
| Environmental: | Sustainable transition. Strong environmental leadership driven by regulation and incentives, rather than technology. |
| Disruptive: | Improved technologies are developed. New and improved technologies enable rapid and disruptive transformation in the energy sector. |

A summary of some key variables for 2050 in each scenario are included in Table 1. Percentage changes relative to 2019 are shown in blue, unless otherwise specified.

| Variable/assumption | EDGS 2019 | | | | |
|--|------------------------|---------------|--------------|---------------|---------------|
| | Reference | Growth | Global | Environmental | Disruptive |
| Grid energy demand | | | | | |
| 2019 energy demand, TWh | 39 | 39 | 39 | 39 | 39 |
| 2050 energy demand, TWh | 57 ↑43% | 65 ↑64% | 47 ↑18% | 67 ↑68% | 71 ↑78% |
| Base energy demand growth, pa | 0.8% | 1.2% | 0.2% | 0.9% | 0.7% |
| Process heat demand, TWh | 1.5 | 1.9 | 1.2 | 6.5 | 13.3 |
| Electric vehicles demand, TWh ³ | 4.1 (44%/13%) | 5.0 (44%/13%) | 3.2(44%/13%) | 7.6 (74%/45%) | 7.6 (74%/45%) |
| Solar PV output, TWh ⁴ | 2.3 (22%) ⁵ | 2.8 (27%) | 0.9 (9%) | 4.6 (45%) | 4.6 (45%) |
| Grid peak demand | | | | | |
| 2019 peak demand, GW | 6.3 | 6.3 | 6.3 | 6.3 | 6.3 |
| 2050 peak demand, GW | 8.5 ↑34% | 9.8 ↑56% | 7.1 ↑12% | 9.6 ↑53% | 10.2↑62% |
| Supply | | | | | |
| New grid generation, GW | 6.3 | 9.4 | 3.8 | 9.6 | 10.6 |
| Environmental | | | | | |
| Carbon price, \$US/t CO ₂ e | \$43 | \$43 | \$43 | \$100 | \$43 |
| Emissions, mt CO ₂ e ⁶ | 23.7 ↑28% | 26.7 ↓19% | 19.6 ↓40% | 17.2 ↓48% | 16.9↓48% |
| Renewables generation, % | 94.9 | 95.4 | 94.8 | 96.0 | 94.9 |

Table 1: Some key variable settings and outcomes of the five scenarios included in the EDGS 2019

³ (x%/x%) refers to light vehicle%/heavy vehicle% of fleet which are electric by 2050

⁴ Solar PV is included as demand. Transpower plans on electricity demand at our GXP's. Domestic solar PV is treated the same as other embedded generation, as a subtractor from gross demand.

⁵ x% refers to the percentage of houses in New Zealand with solar PV panel installations

⁶ 2050 energy sector emissions, compared to 2017 emissions



Why do we need to vary the EDGS 2019

Several events in recent times mean that the EDGS 2019 are no longer up to date. These events include:

- COVID-19 effect on electricity demand
- MBIE generation cost stack and potential new generation plants information
- Tiwai aluminium smelter closure
- Tiwai closure effect on North Island thermal generators
- Meridian's and others interest in grid-scale batteries
- Government investigation of Onslow pumped hydro scheme i.e. the NZ battery workstream
- Funding to accelerated decarbonisation of South Island industrial plants
- Publication of EA's TPM guidelines

all of which create additional uncertainty in the electricity supply and demand forecasts.



Do you agree that EDGS 2019 need to be reviewed for the purposes of our ASILR and NZGP projects?

Scenario Development Panel

To assist with determining reasonable variations to the EDGS 2019 we invited external experts to join a panel of advisors. The panel members are:

John Hancock – Facilitator
Paul Botha – Roaring 40's
Pauline Martin – Genesis Energy
Allan Miller – Allan Miller Consulting
Marcos Pelenur – EECA
Jen Purdie – University of Otago
Glenn Sullivan – Fonterra
Ryno Verster – Powerco
Philip Wong Too – Tilt Renewables



Panel online meetings⁷

The panel has met twice in online meetings, convened and facilitated by John Hancock.

The first meeting was held on November 5th, 2020 and at that meeting the panellists considered a range of questions regarding scenario variable settings.

A pre-reading document was provided to the panellists, which can be viewed here:

and a recording of the first online panel meeting can be viewed here.



The second meeting was held on December 2nd 2020. A pre-reading document describing our summary of the panel's recommendations from the first online meeting and an overview of their effects was provided to the panellists and this can be viewed here:

At the second online panel meeting, we described the outcome of the panel's advice and our own consideration of that advice, being the first draft of the EDGS 2019 variations. The panel were asked for their opinion on the first draft of the EDGS 2019 variations.

A recording of the second online panel meeting can be viewed below.



⁷ Insights from the panellists were extremely useful and we would like to thank the panellists for their time and contributions to date.

EDGS 2019 Variations Take One

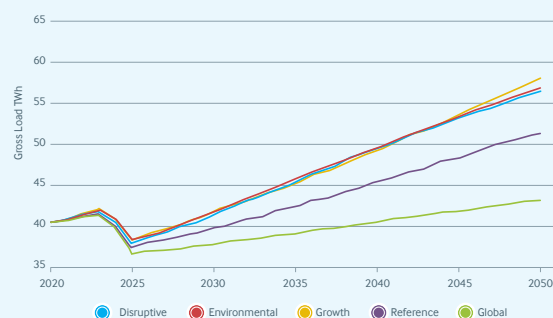
Following our first online meeting we collated the panels feedback and incorporated it into a revised set of demand scenarios. The result was interesting – we effectively reduced the five demand scenarios to three, as three of the scenarios coincided.

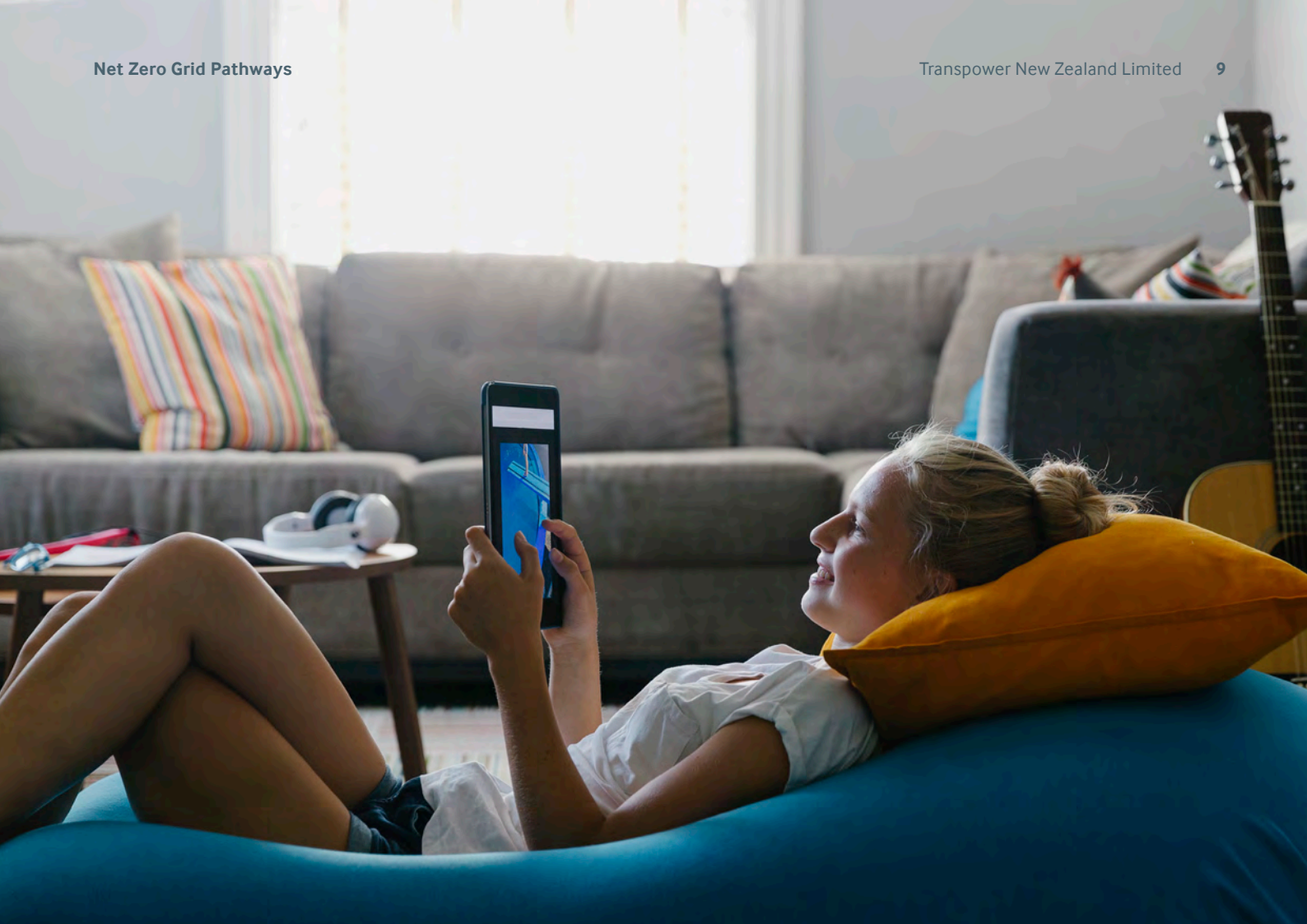
The difficulty with these revised scenarios is that:

We undertake economic analysis for each scenario separately and then weight the results to determine an average outcome. The default probability is to assume each scenario is equally likely. If we use that logic for the scenarios above, we are effectively assigning a 60% probability to the outcome where the scenarios overlap. That is an unlikely outcome.

To be useful, the demand scenarios need to represent a diverse range of futures in order that we test various transmission options over a range of possible futures.

EDGS Variations Take One





We considered demand and supply scenarios separately

Some of the changes that have occurred since the July 2019 EDGS, impact the electricity demand scenarios and some impact the electricity supply scenarios.

In our view the mixture of demand and supply scenarios included in the EDGS 2019 may not be the most appropriate anymore, given those changes, so we have considered demand and supply scenarios separately.

We describe later in this document how we propose to derive suitable demand and supply scenario combinations for our investigations.



Question 2

Is it reasonable to consider the demand and supply scenarios separately?

Draft EDGS 2019 demand scenario variations

The EDGS 2019 demand forecasts reflect an amalgamation of the forecast of many different variables.

For the purposes of this consultation, we discuss each forecast element separately and then present the result as an overall forecast – either an energy demand forecast or peak demand forecast.

The discussion reflects our draft EDGS 2019 variations, which reflect the panel's feedback from both online meetings.

Tiwai closure

There are two aspects to Tiwai closure which are important to the demand forecasts:

- The date on which the Tiwai aluminium smelter begins to close
- The phasing of the closure i.e. whether it closes all at once, or gradually over time

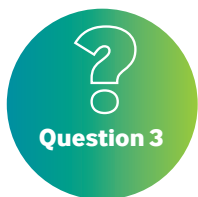
Tiwai closure date

Although we have no particular information at this stage, the panel felt that a closure deferral is likely and so we are using a closure date of August 2024, rather than August 2021, in all scenarios.

This is a variable that is important in the analysis, but it did not seem appropriate to vary it across the scenarios. Hence, we are proposing to include August 2021 and August 2026 as possible sensitivities, noting that a public announcement may have been made by the time the scenarios are finalised.

Tiwai phased closure

The panel was unanimous in suggesting that a phased closure of the Tiwai aluminium smelter is unlikely and that it is more likely to fully close all at once. We have adopted this suggestion.



Are our assumptions in regard to Tiwai's closure reasonable:

- a) Tiwai will close August 2024**
 - b) We will include August 2021 and August 2026 as potential sensitivities**
 - c) Tiwai closure will not be phased. It will fully close on the assumed closure date**
-

Impact of COVID-19

The effect of COVID-19 on electricity demand is difficult to predict, since such an event has not occurred previously.

Our assumptions are loosely based on NZIER and Reserve Bank forecasts around the New Zealand economy, which see a temporary flattening and a resumption of growth from about mid-2022.

Real GDP, annual total

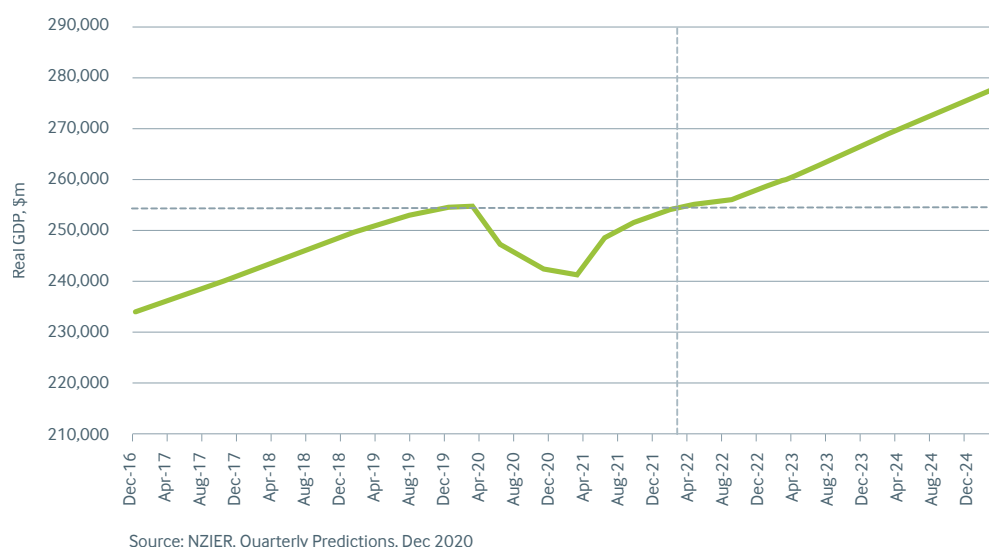
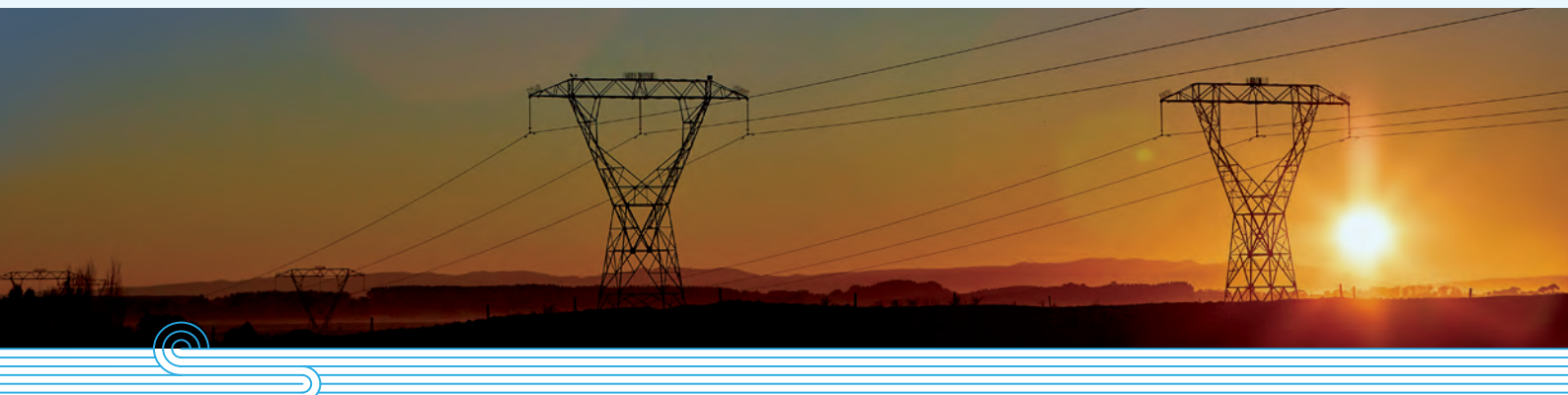


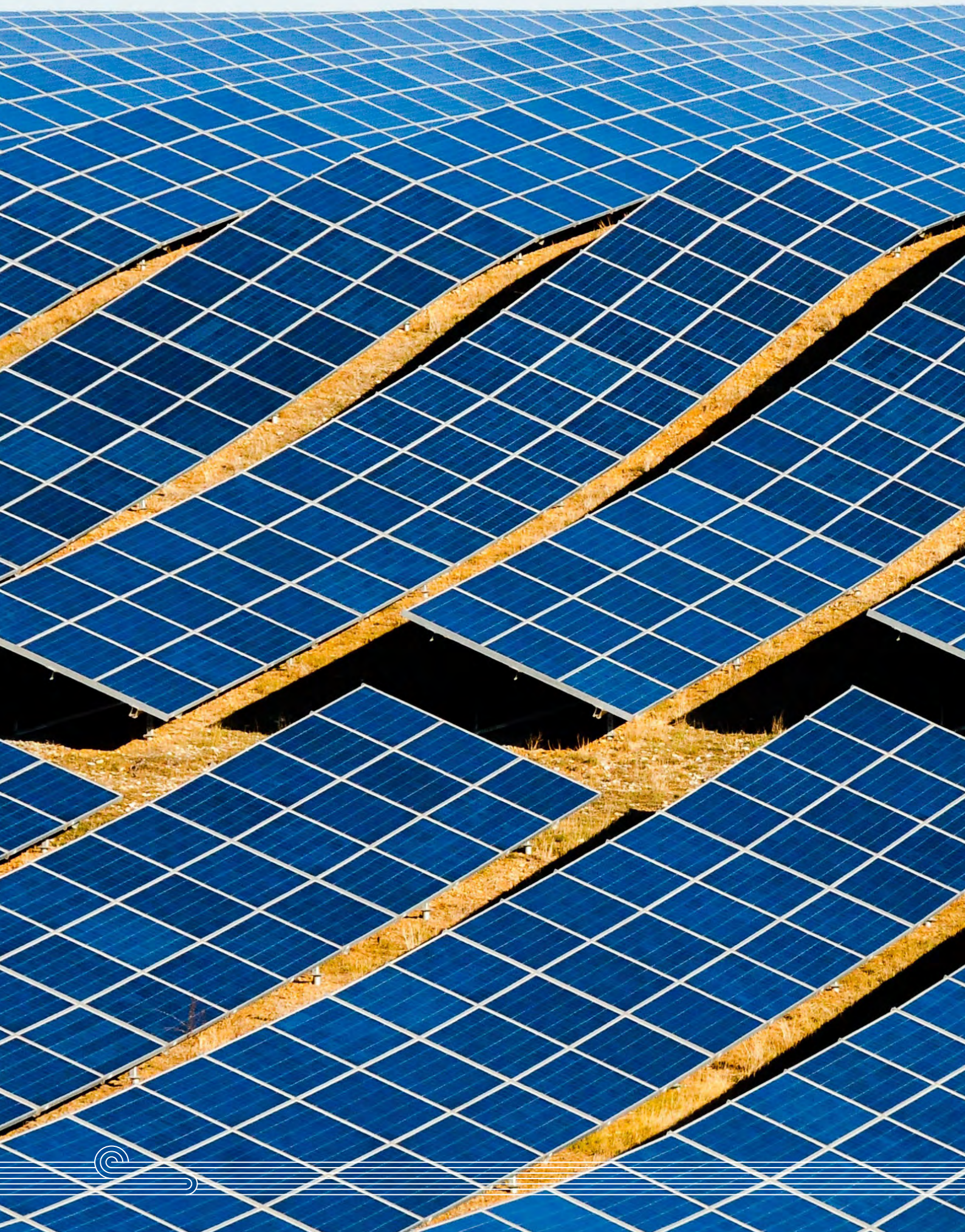
Figure 2: NZIER forecast of New Zealand GDP until end 2024

Variation across scenarios versus sensitivities

When considering how to reflect a variable across the scenarios, there are two main choices:

- Define different settings for the variable and work those settings into the various scenarios. Each scenario has an underlying "story" (e.g. the global scenario is one where New Zealand's economy is battered by international trends, leaving little room for growth or innovation) and so the setting should be consistent with that story; or
- Recognise that the variable settings are not related to any particular story and any setting could apply in any scenario. In this case, rather than associate the variable settings with scenarios, it may be more appropriate to use a single setting in all scenarios and reflect the other settings as sensitivities, to be treated in the analyses as relevant.





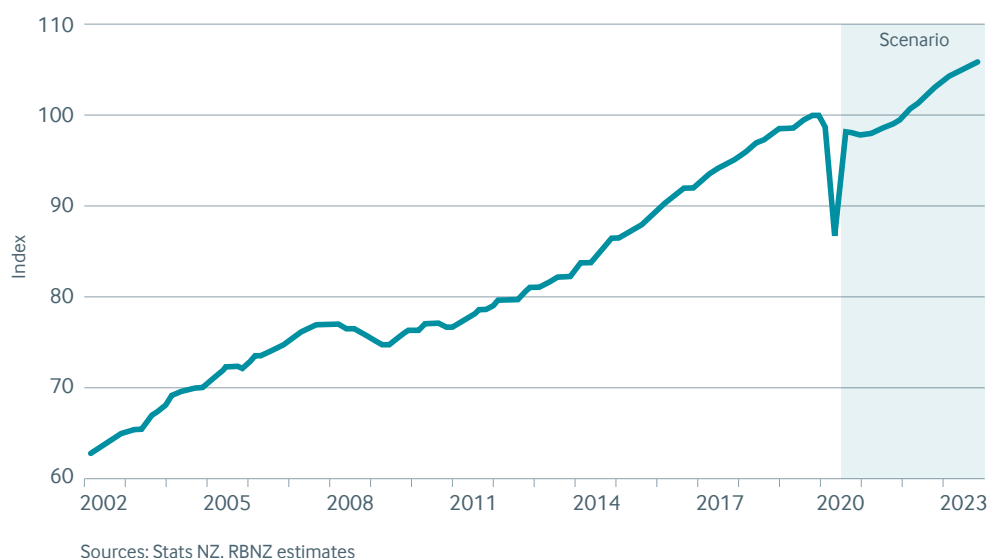


Figure 3: RBNZ forecast of New Zealand GDP index until end 2023

We have translated these effects into the following variations for each scenario:

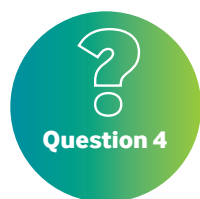
Reference scenario – 1 year of “no growth” in base demand component, then return to 0.5% CAGR⁸

Growth scenario – 1 year of “no growth” in base demand component, then return to 0.7% CAGR

Global scenario – 2 years of “no growth” in base demand component, then return to 0.1% CAGR

Environmental scenario – 1 year of “no growth” in base demand component, then return to 0.6% CAGR.

Disruptive scenario – 1 year of “no growth” in base demand component, then return to 0.4% CAGR.



Are our assumptions in regard to the effect COVID-19 may have on electricity demand reasonable?

Base energy demand forecast

Base demand equals traditional electricity consumption by domestic, commercial and industrial consumers, but it excludes industrial process heat and transport consumption, which are considered separately.

Historically, base demand was closely correlated with New Zealand’s GDP and population growth, but that correlation diminished in the early 2000’s. It is unlikely there is a single cause, with two of the main contributors hypothesized to be:

- Energy efficiency – the emergence of more energy efficient technology, including a change in light bulb technology from incandescent to LED
- Development of the service sector – there has been a gradual change in New Zealand business, away from energy intensive industry (particularly as manufacturing has globalised), toward being more of service sector based.

⁸ CAGR = Compound Annual Growth Rate

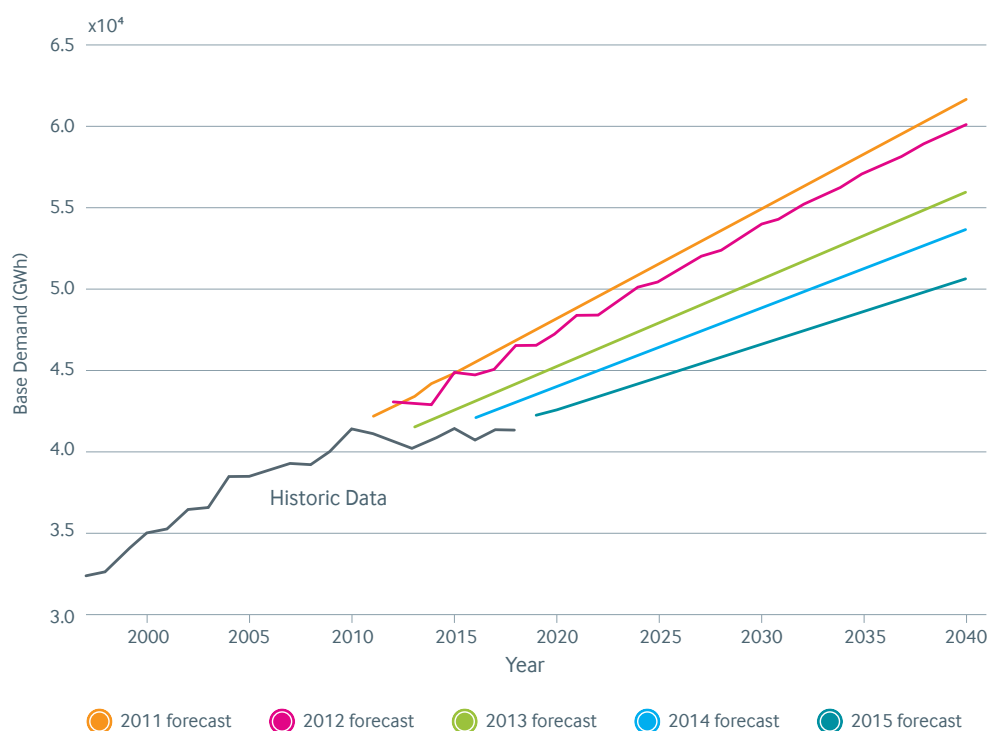


Figure 4: Diagram showing how compound average growth rate (CAGR) has decreased consistently since approximately 2010. Prior to 2010, CAGR was between 1.9% and 2.7%, averaging approximately 2.3%. Since 2010, CAGR has plummeted to between 0.1% and 0.6%, averaging approximately 0.4%.

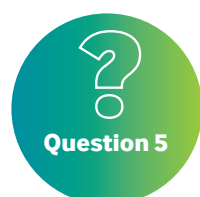
It should be noted that the CAGR shown in Figure 4 represents growth for total electricity demand and not just base demand, however the two are closely related.

Our discussion with the panel concluded that the base demand growth rates included in the EDGS 2019 were high and lower growth rates would be more appropriate.

The base demand growth rates assumed in EDGS 2019 are shown below, along with our draft variations:

| | Global | Reference | Growth | Environmental | Disruptive |
|-----------------------------------|--------|-----------|--------|---------------|------------|
| EDGS 2019 | 0.2% | 0.8% | 1.2% | 0.9% | 0.7% |
| Draft EDGS 2019 variations | 0.1% | 0.5% | 0.7% | 0.6% | 0.4% |

Table 2: Base demand growth rates for EDGS 2019 and our draft EDGS 2019 variations



Are our base demand growth assumptions reasonable variations of the EDGS 2019 assumptions?



Industrial energy demand

The panel felt that Tiwai's closure is not expected to be the only existing major industrial plant closure between now and 2050. Some other major industries are also under increasing international pressure and may close.

The EDGS 2019 does not reflect existing industrial plant closure and it is difficult to forecast when and which industrial plants may close. The panel recommended a 20% reduction in existing industrial demand. Rather than reflect such a reduction in all scenarios, as then our assumption is that such a reduction is a certainty, we are proposing to assume a 567 GWh reduction in existing industrial demand in both the Global and Environmental scenarios. The underlying story for those scenarios is most consistent with such a reduction.

Although existing industrial demand may decrease, the panel also felt that New Zealand may be seen as a safe haven for some emerging industries. As a result, we may also see some industrial demand growth. The examples that were most cited were data centres and hydrogen production facilities. Data centres have relatively low electricity demand requirements, while electricity demand at hydrogen production facilities could be large.

Demand growth in these areas is relatively speculative and so we are proposing not to reflect such potential in our industrial energy demand forecasts, but rather to include some sensitivities, which would be assessed as relevant to the transmission investigation.

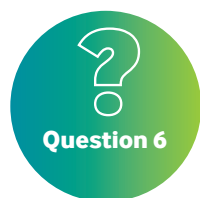
Our proposed sensitivities are:

| Demand MW | |
|-------------------------------|---|
| Tiwai replacement load | Up to 300 MW immediately following Tiwai exit |
| Auckland load | Up to 100 MW by 2030 |

Table 3: Proposed industrial demand sensitivities

The panel discussed potential Tiwai replacement loads. Potential data centre loads may be small (<100 MW), whereas new manufacturing load of some sort (e.g. a hydrogen manufacturing facility) could be larger.

We are proposing to sensitise new industrial load in Auckland because the likes of new data centre load may emerge there and it is geographically different to the lower South Island, so provides diversity for our analyses.



Are our proposed industrial energy demand variations reasonable:

- **A reduction of 567 GWh in existing industrial demand (approximately 20% of industrial demand from direct grid connections, excluding Tiwai) in the Global and Environmental scenarios**
- **The inclusion of two sensitivities for new industrial load at Tiwai and in Auckland, to be considered as relevant in our analyses.**





Process heat electrification

The panel felt that the process heat electrification assumptions in the EDGS 2019 were low.

The EDGS 2019 assumptions for demand growth as a result of process heat electrification assumed 15% of low temperature heat in the Reference scenario, ~55% of low and medium heat in Environmental and ~83% of all heat in Disruptive. The EDGS 2019 process heat energy demands were taken from the 2016 EECA Energy End Use Database (EEUD). The EEUD informs these assumptions, in particular the efficiency comparison between the use of coal, gas and electricity for each temperature category. Recent updates to the EECA EEUD mean the percentages reflected in EDGS 2019 may no longer be appropriate. Panel advice was that the demand from low temperature process heat was too low, but that the total Demand in the Disruptive scenario was too high. This is consistent with the changes reflected in the EECA EEUD update and we have increased the low temperature demand while keeping the high demand in the Disruptive scenario in order to provide diversity in the scenarios.

2050 Process Heat

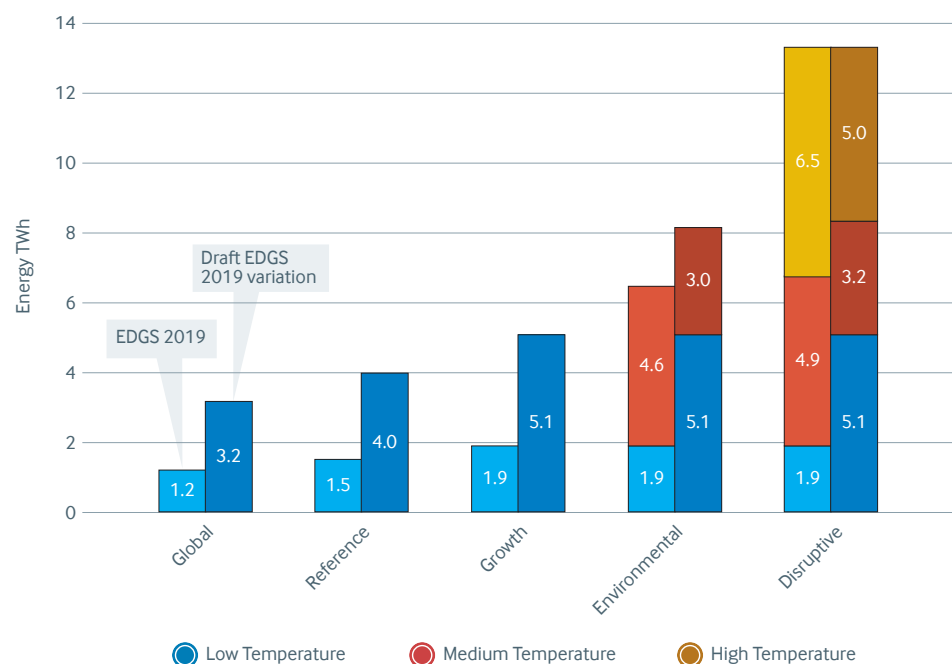
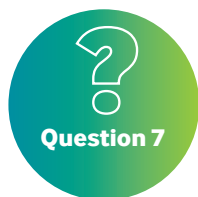


Figure 5: The demand from process heat electrification in 2050 for each scenario. The blue, red and yellow bars represents the demand from low, medium and high temperature processes. For each scenario, the lighter shades on the left shows the 2019 EDGS, the darker shades on the right show the draft 2019 variations.



Are our proposed process heat electrification demand variations, as shown in Figure 5 reasonable?

Electric vehicle demand

The EDGS 2019 includes electricity demand assumptions that reflect an uptake of both light and heavy electric vehicles.

The EDGS assumptions are that 44% of the light vehicle fleet will be electric vehicles by 2050 in the Global, Reference and Growth scenarios and 74% of the light vehicle fleet in the Environmental and Disruptive scenarios.

13% of the heavy vehicle fleet is electrified in the Reference scenario by 2050 and the range over all scenarios is 13-45%.

The panel thought the assumptions for light vehicles were low and should be increased.

We have increased the light vehicle demand to reflect 60% of the light vehicle fleet being electric by 2050 in the Global, Reference and Growth scenarios and 90% of the light vehicle fleet in the Environmental and Disruptive scenarios. The heavy vehicle assumptions are not changed.

The uptake of electric vehicles is an important assumption for transmission planning, not only because of the increase in electricity demand, but also because the charging regime used by electric vehicle owners can have a significant effect on peak transmission demand. The latter issue is discussed in the “Smartness” section of this document.

The resultant energy demand forecasts for electric vehicles, by scenario, are shown in Figure 6.

2050 Electric Vehicle demand

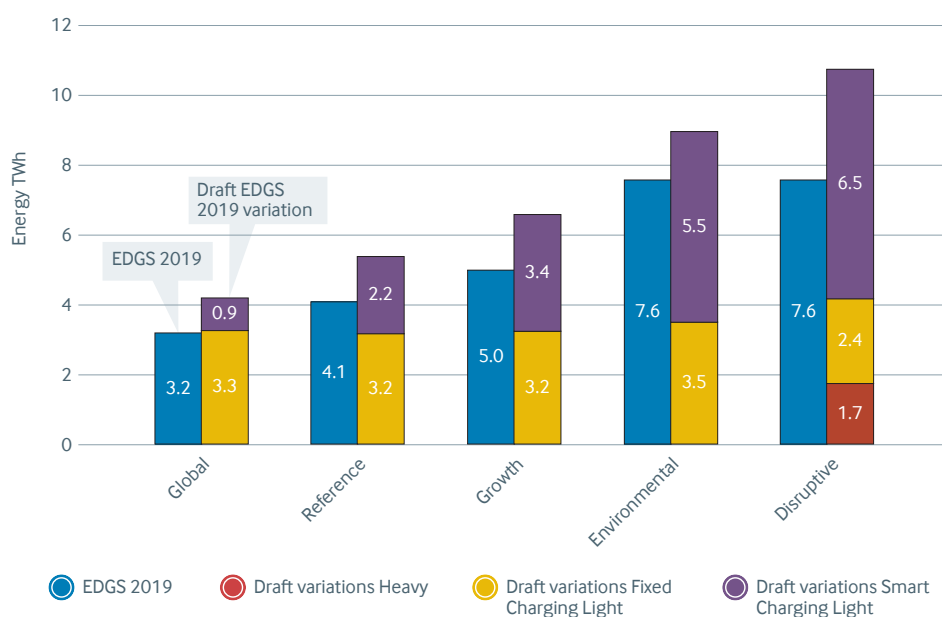
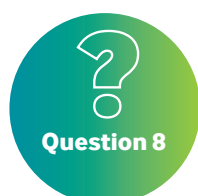


Figure 6: The demand from electric vehicles in 2050 by scenario. The blue bars represent the EDGS 2019, the stacked red, yellow and purple bars represent the breakdown of Heavy vehicle demand, Light, fixed charging, vehicle demand and Light, smart charging vehicle demand. The ‘smartness’ of the charging is discussed below.



Are our proposed electric vehicle energy demand variations, as shown in Figure 6, reasonable?

Rooftop solar PV

We include rooftop solar PV in our discussion on demand scenarios, rather than supply scenarios. The reason for this is that rooftop solar PV is located on domestic household and commercial premise roofs, which are “embedded” and “behind” our substations, or grid exit points. Their output reduces the electricity demand required from the transmission grid, just as other embedded generation (i.e. not grid-connected) does.

We treat rooftop solar PV as a demand reduction when we forecast grid exit point electricity demand.

The panel view was that the rooftop solar PV forecasts in the EDGS 2019 were low.

The number of solar PV installations ranged from 22% of houses in 2050 in the Reference scenario to 45% of houses in the Environmental and Disruptive scenarios. Commercial solar PV was not reflected in the EDGS.

We propose increasing the proportion of houses with solar PV installations to be 33% of houses in 2050 in the Reference scenario and 68% of houses in the Environmental and Disruptive scenarios. This is a proxy for increasing both domestic and commercial rooftop solar PV.

It was noted that currently, commercial rooftop solar PV is an economic proposition, whereas using the same economic approach, domestic rooftop solar PV is not.

Our resultant proposed rooftop solar PV demand forecasts, compared to EDGS 2019, are shown in Figure 7.

Demand forecasts for transmission planning

The EDGS reflect gross electricity demand, being a forecast of electricity consumed by end users.

Forecasting gross electricity demand makes sense because then electricity demand can be compared to other forms of energy demand, which are also forecast at end-user level.

However, for transmission planning we are interested in the electricity demand at our substations, otherwise called grid exit points.

For our internal use we change the EDGS electricity demand forecasts into grid exit point forecasts by subtracting embedded generation and adding distribution line losses.



2050 Solar Generation

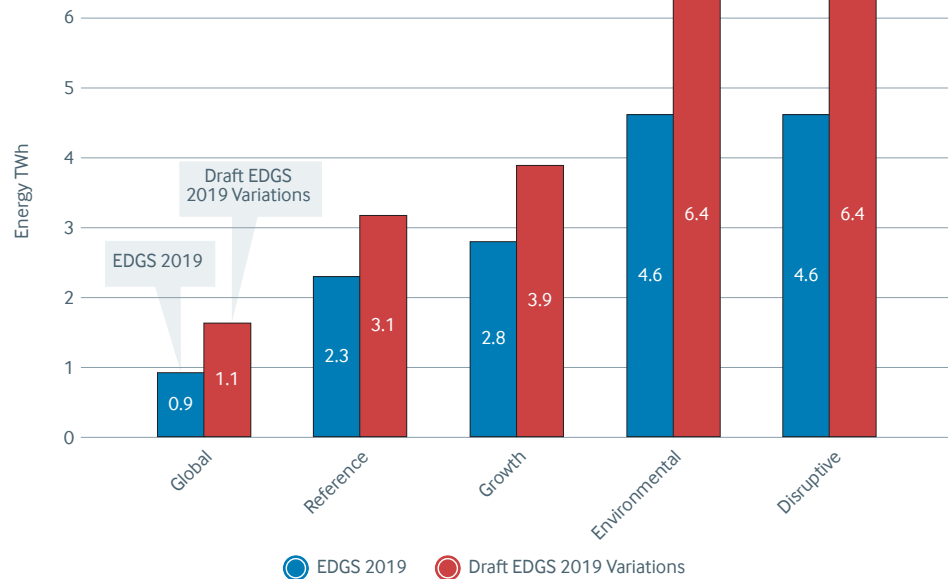
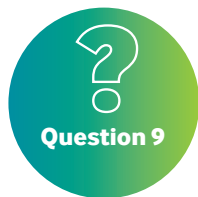


Figure 7: The total energy generated in 2050 by rooftop solar for each scenario. The blue bars represent the 2019 EDGS, the red bars are the draft EDGS 2019 variations.



Are our proposed rooftop solar PV variations, as shown in 7, reasonable?

Summary graphs of energy demand

Having discussed several separate input variables into the energy demand forecast, our draft EDGS 2019 variations compared to the EDGS 2019 are shown in Figure 8. Note that we have reflected Tiwai closure at the end of 2024 into the EDGS 2019 demand forecasts.

EDGS 2019 cf draft EDGS 2019 variations inc Tiwai closure

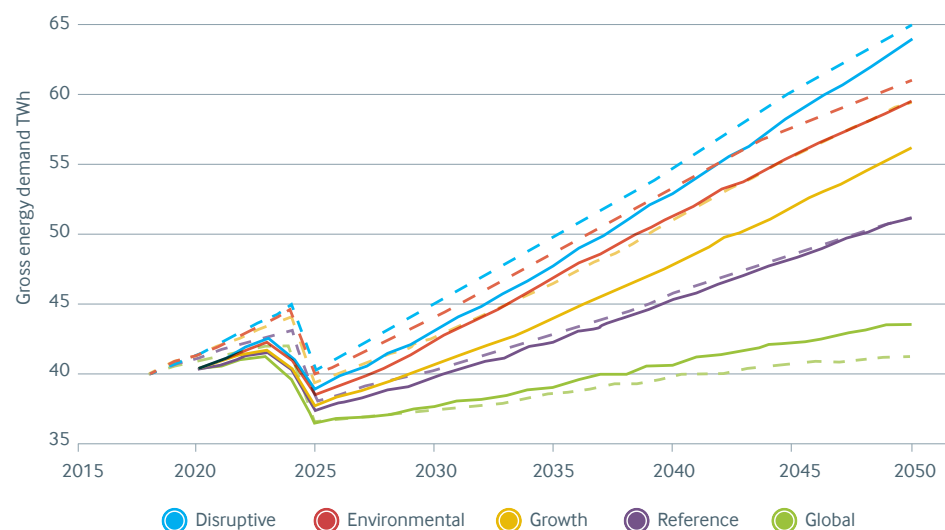


Figure 8: Gross energy demand in the five scenarios. The draft EDGS 2019 variations are plotted as the solid lines, the 2019 EDGS, with Tiwai closure are shown as dotted lines.

As seen, although we have increased some variables and reduced others, the overall effect is that our draft EDGS 2019 variations are not dissimilar to the original EDGS 2019 (noting that we have modified the original EDGS 2019 demand forecasts to include Tiwai exit in 2024).

Our draft EDGS 2019 variations include a similar level of diversity to the original EDGS 2019.

In some respects, this may seem surprising. However, we have lowered the base demand growth, in line with current expectations and increased the uptake of new technologies which will contribute to reducing New Zealand's carbon emissions, also in line with current expectations. Although these national demand forecasts appear to offset each other, the demand profiles (i.e. the hourly profile throughout the year) are different, due to the different make-up between base energy, industrial energy, process heat electrification, electric vehicle demand and rooftop solar PV output.



Are our proposed EDGS 2019 variations for energy demand reasonable?

By way of a summary and for comparison, Figure 9 and Table 4 compare the variable settings for each scenario in the original EDGS 2019 and the variable settings we propose in our draft EDGS 2019 variations.

2050 Total Demand

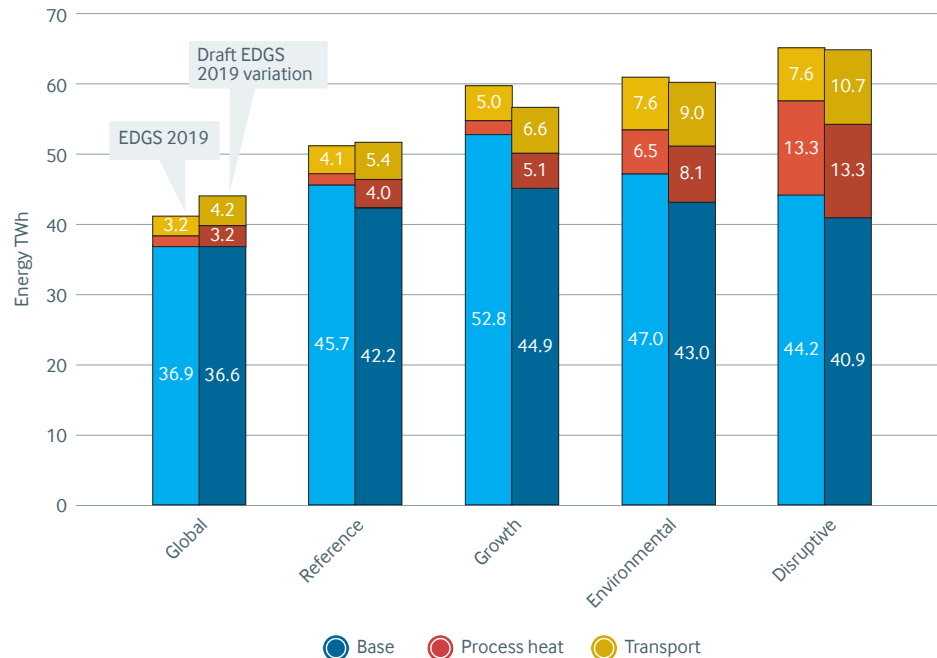


Figure 9: The total demand in 2050 for each scenario. The blue, red and yellow bars represents the demand from base growth, process heat electrification and demand from electric vehicles. For each scenario, the lighter shades on the left shows the 2019 EDGS, the darker shades on the right show the 2019 variations.

Summary table comparing EDGS 2019 and draft EDGS 2019 variations

| Variable/assumption | EDGS 2019 | | | | | Draft EDGS 2019 variations | | | | |
|--|--|---------|---------|---------------|------------|--|-------------------------------|-------------------------------|-------------------------------|-------------------------------|
| | Reference | Growth | Global | Environmental | Disruptive | Reference | Growth | Global | Environmental | Disruptive |
| Scene setting issue | | | | | | | | | | |
| Net zero C by 2050? | N | N | N | N | N | Y | Y | Y | Y | Y |
| Extent electrification contributes | Incorporated in individual assumptions | | | | | Incorporated in individual assumptions | | | | |
| Grid energy demand issues to consider | | | | | | | | | | |
| Base energy demand growth | 0.8%pa | 1.2%pa | 0.2%pa | 0.9%pa | 0.7%pa | 0.5%pa | 0.7%pa | 0.1%pa | 0.6%pa | 0.4%pa |
| Existing industrial energy demand change | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -567 MWh by 2030 | -567 MWh by 2030 | 0 |
| Process heat electrification, TWh | 1.5 TWh | 1.9 TWh | 1.2 TWh | 6.5 TWh | 13.3 TWh | 4.0 TWh | 5.1 TWh | 3.2 TWh | 8.1 TWh | 13.3 TWh |
| Accelerated decarbonisation in SI? | N | N | N | N | N | N | N | N | N | N |
| Heavy electric vehicle, fleet % | 13% | 13% | 13% | 45% | 45% | 13% | 13% | 13% | 45% | 45% |
| Light electric vehicle, fleet % | 44% | 44% | 44% | 74% | 74% | 60% | 60% | 60% | 90% | 90% |
| Solar PV output | 2.3 TWh | 2.8 TWh | 0.9 TWh | 4.6 TWh | 4.6 TWh | 3.1 TWh | 3.9 TWh | 1.1 TWh | 6.4 TWh | 6.4 TWh |
| COVID-19 effect | N | N | N | N | N | Y | Y | Y | Y | Y |
| COVID-19 reflected by | | | | | | 1yr flat then normal | 1yr flat then normal | 2yr flat then normal | 1yr flat then normal | 1yr flat then normal |
| Tiwai closure | N | N | N | N | N | 2024 | 2024 | 2024 | 2024 | 2024 |
| Tiwai closure phasing | N | N | N | N | N | N | N | N | N | N |
| Tiwai replacement load | N | N | N | N | N | N | N | N | N | N |
| Grid peak demand issues to consider | | | | | | | | | | |
| Embedded storage utilised | | | | | | Same as EDGS 2019 | | | | |
| EV storage available for peak shaving | | | | | | 1% | 1% | 0 | 1% | 1% |
| EV storage offered for peak shaving | | | | | | 50% | 40% | 20% | 60% | 60% |
| Grid-scale batteries | N | N | N | N | N | Y | Y | Y | Y | Y |
| Supply scene setting issue | | | | | | | | | | |
| Renewable generation target/date | | | | | | N | N | N | N | N |
| Supply issues to consider | | | | | | | | | | |
| Rankine retirement | 2030-31 | 2030-31 | 2030-31 | 2030-31 | 2030-31 | 2023-30 No coal after 2025 | 2023-30 No coal after 2025 | 2023-30 No coal after 2025 | 2023-30 No coal after 2025 | 2023-30 No coal after 2025 |
| TCC retirement | | | | | | 2025 | 2025 | 2025 | 2025 | 2025 |
| Cost new generation technologies | N | N | N | N | N | Y | Y | Y | Y | Y |
| Dry year reserve | | | | | | see p36 | see p36 | see p36 | see p36 | see p36 |
| Other issues | | | | | | | | | | |
| Carbon price \$US/t CO2e | \$43/t | \$43/t | \$43/t | \$100/t | \$43/t | \$NZ75/t | \$NZ75/t | \$NZ30/t | \$NZ200/t | \$NZ75/t |
| TPM changes | N | N | N | N | N | N | N | N | N | N |

Table 4: Summary table of EDGS 2019 and draft EDGS 2019 variations





Smartness

Although energy demand forecasting is a critical part of developing scenarios for transmission planning, the grid is largely planned around peak electricity demand. The transmission grid needs to be able to meet peak demand in order to ensure a reliable supply of electricity to consumers and we build transmission capacity accordingly.

The electricity system of the future will be considerably different to now and we expect there will be many ways of ensuring peak electricity demand can be met other than by building transmission assets - including by reducing demand at peak times.

For example, demand response will be available. Although this is available now to an extent, in the future many household appliances are expected to be smart and controllable.

Batteries are likely to fall in price and will be routinely installed with rooftop solar PV systems.

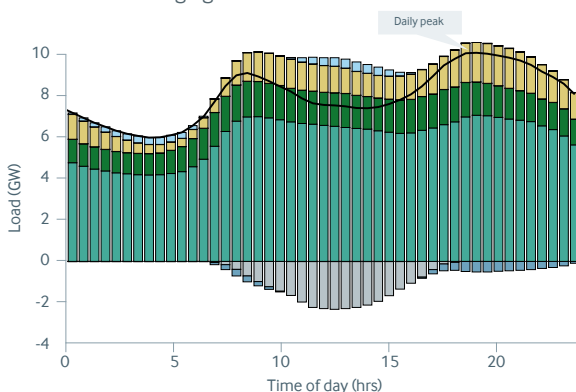
Electric vehicles include a large battery. This is potentially positive and negative for the power system, including the transmission system. Positively, it may be possible to use these batteries, while connected to the power system, for peak demand shaving. Negatively, if electric vehicle charging is not coordinated and all electric vehicles plug in at the same time to charge, the system would be overloaded.

Importantly, if these technologies and devices were coordinated and used for peak demand shaving, we could reduce the requirement for new transmission assets. In reality, personal preferences and competing uses for these technologies will mean that only a portion will be available for peak demand shaving. It is not clear how economic transmission peak demand shaving will be, compared to the alternatives that individuals will have, so it is not clear what proportion of such “smartness” we should assume in developing scenarios and in our transmission planning.

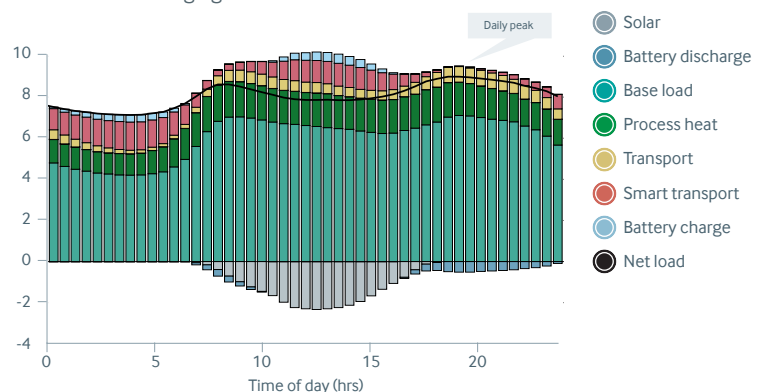
By way of illustration, the following diagrams show how, if such devices were coordinated, they could reduce peak demand on the transmission grid.

Smart charging of electric vehicles

Without smart charging



With smart charging



1.2 GW can be shaved off peak by assuming 60% of electric vehicles smart charge.

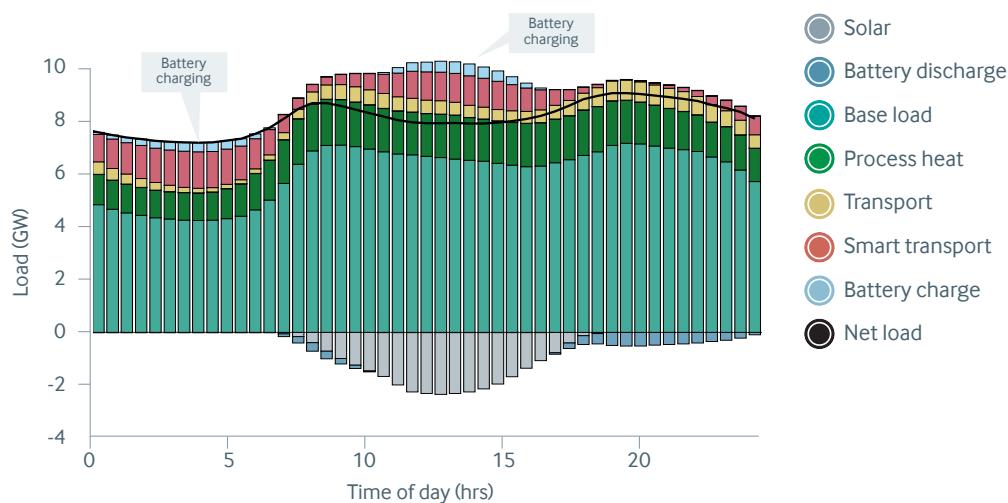
Figure 10: The effect of 'smart' vehicle charging on a daily profile. In the panel on the left the yellow bars represent the daily profile associated with 'fixed' charging of electric vehicles. The peak, in the fixed charging coincides with the daily net peak (black line). In the panel on the right, the pink bars represent a profile from 'smart' charging where the peak is explicitly ignored.

As Figure 10 shows, smart charging of electric vehicles, coordinated on a regional basis⁹, could reduce national peak demand by 1.2 GW, if 60% of the electric vehicles in 2050 were coordinated.

Figure 11 and Figure 12 illustrate that the coordinated use of embedded storage (associated with rooftop solar PV and a limited amount of EV storage) could contribute a further 0.8 GW of peak shaving if it was coordinated.

This is the same assumption as included in the EDGS 2019.

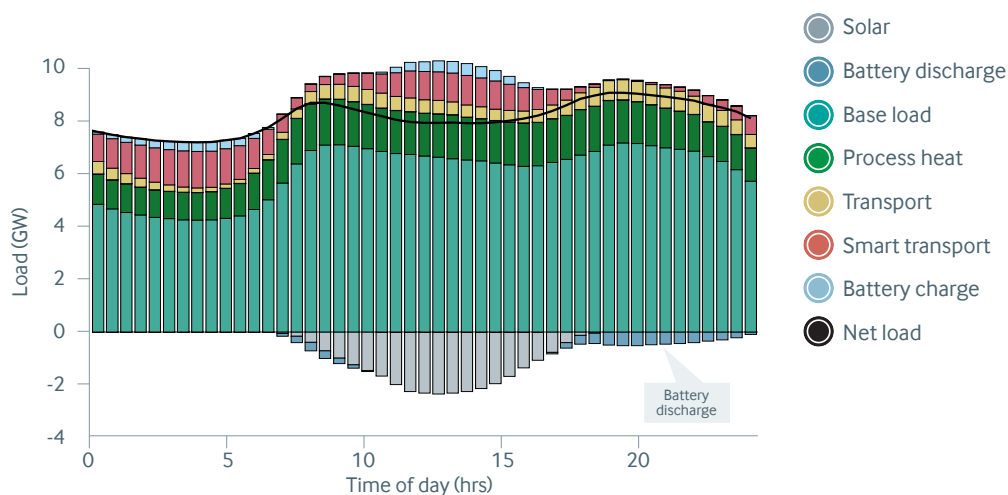
Demand response via smart embedded storage



Embedded storage devices charge during troughs

Figure 11: Batteries charging within a daily profile. The battery charging profile is shown in light blue. The batteries are allowed to charge during troughs, that is, during the night in response to pricing signals and during the mid day trough due to solar excess.

Demand response via smart embedded storage



Embedded storage devices discharge into peaks, this shaves around 800 MW off the peak

Figure 12: Batteries discharging within a daily profile. The discharging profile is represented by the dark blue bars. Batteries can reduce the net load (black line) by discharging during the evening peak.

⁹ Coordination on a regional basis means that electric vehicle charging is coordinated to avoid the regional peak demand.

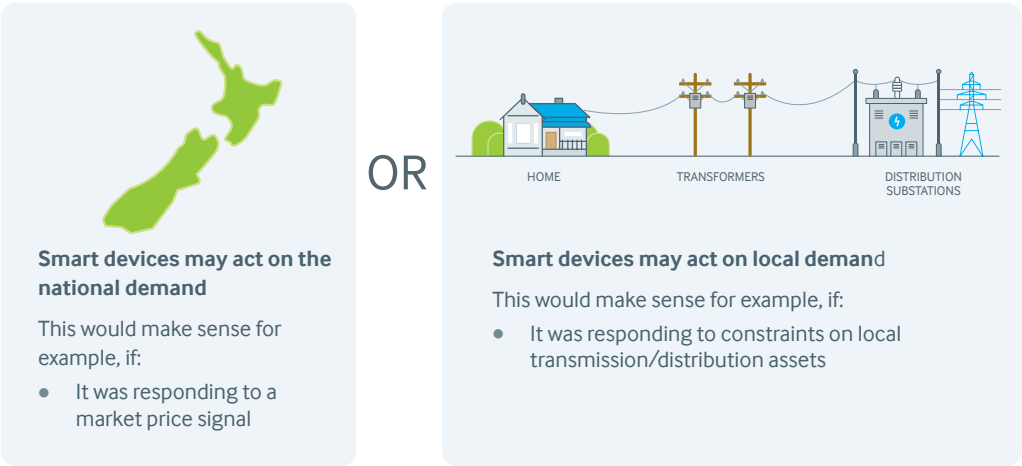
Combined, electric vehicles and domestic batteries would therefore result in 2 GW of peak shaving using these assumptions.

These numbers ignore the potential from smart domestic appliances.

The market arrangements required to provide consumer choice are not in place yet. We are aware that early discussions are occurring in regard to such arrangements and there is some discussion around distribution level coordination, but it will be some time before we are able to reflect realistic assumptions in our forecasting.

Absent clarity, our draft EDGS 2019 variations assume that such smartness is neither coordinated at a national level, or at a localised level, but is coordinated at a regional level.

Who controls the smartness?



EDGS variations assume the smart devices act at a regional level.

Figure 13: The ‘smartness’ can, in principle, be applied and controlled at different geographical levels. In the variations presented here we assume that the smartness is effective at a regional level.

| | Global | Reference | Growth | Environmental | Disruptive |
|--|---------------------------|-----------|--------|---------------|------------|
| Smart charging % | 20% | 40% | 50% | 60% | 60% |
| Solar PV storage used for peak shaving | Same as used in EDGS 2019 | | | | |
| Electric vehicle storage used for peak shaving | 0% | 1% | 1% | 1% | 1% |



Are our assumptions re the level of “smartness” available for peak demand shaving reasonable?



Summary graphs of peak demand

The result of applying our smartness assumptions is the following peak demand forecast, by scenario, in 2050:

2050 Peak

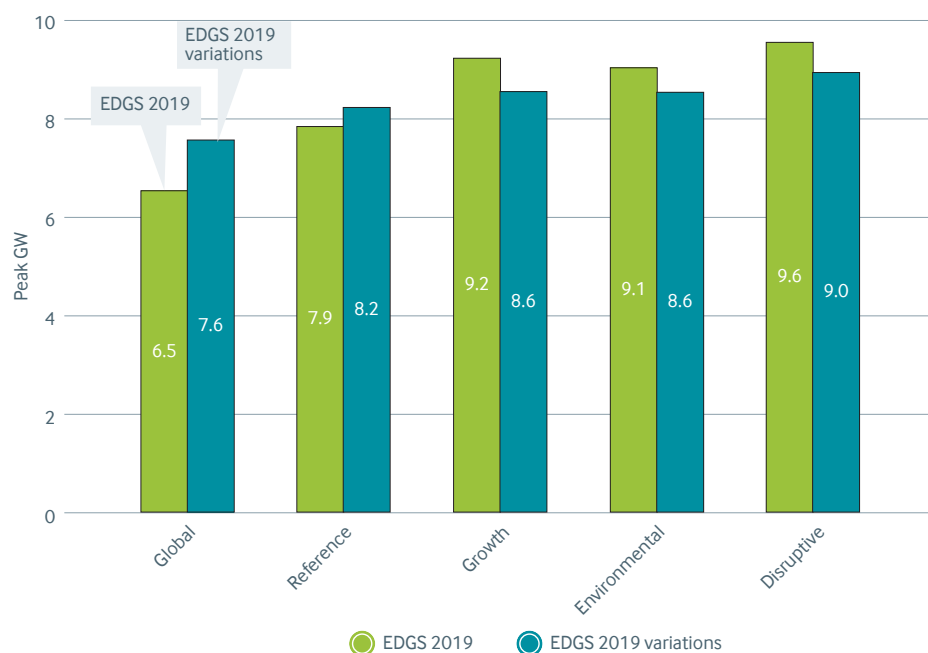
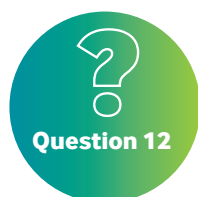


Figure 14: The net peak in 2050 for each scenario. The green bars represent the 2019 EDGS, the teal bars are the variations.

In the Reference and Global scenarios, we have been conservative with estimates of peak shaving, which seems consistent with the scenario narrative.

In the Growth, Environmental, and Disruptive scenarios, we have assumed higher levels of peak shaving, which also seems consistent with those scenario narratives.



**Are our draft peak demand
EDGS 2019 variations reasonable?**





Draft EDGS 2019 supply scenario variations

Supply scenarios describe the electricity generation that will be built to meet the forecast electricity demand. Scenarios which reflect higher demand in 2050, will also require more generation to be built.

Generation tends to fill one of three different purposes:

- 1) Generation is built to provide a sustained energy supply. The economics of such plants depend upon the long-term cost of energy.

Some technologies such as geothermal and most hydro provide a relatively constant supply of energy and are termed baseload. Other technologies such as wind and solar depend upon whether the wind is blowing, or the sun is shining, to determine how much energy they produce. These technologies are termed intermittent, but both baseload and intermittent generation can provide sustained energy. We call this “energy supply” generation.

- 2) Generation technology which balances the inherent intermittency of some generation technologies, or which meets intermittent peak demands (e.g. during winter). The economics of these plants depend upon the cost of energy at peak times and they may operate for only a single or a few trading periods at a time. We call this “peak supply” generation.
- 3) Generation technology which provides sustained energy during hydrological dry years. Whilst the peaking generation described above covers short term intermittency in generation or demand, the need for dry year reserve is different. In dry hydrological years there is a need for a sustained energy supply over multiple concurrent trading periods. We call this “dry year reserve” generation. This function is currently filled by existing thermal plants.

We have considered how supply scenarios could be constructed which meet all three of these generation purposes and have concluded that a set of scenario possibilities should be derived for each separately. There is too much uncertainty about future electricity supply options to rely on just five scenarios. The supply possibilities are more varied in their transmission requirements than the demand possibilities and to ensure we analyse a comprehensive range of future requirements; we are proposing to consider the three supply purposes separately for now.

Our approach is described below, along with a proposal for deriving scenarios useful for our investigations.

Generation stack update

The generation stack was updated by MBIE in 2019/20.

When assembling the supply side of the EDGS, a least-cost generation expansion model is used. That model includes a list of potential new generation projects. Each potential project is described by technology (e.g. wind, hydro, etc), size (MW), location and cost (both capital and ongoing). The generation expansion model chooses new generation off the stack, as required to meet the demand forecast, at minimum cost. The model is complex and considers reliability of supply in making its assessments.

The existing generation stack was produced in 2011, hence an update was timely. Five reports were commissioned to update the generation stack information, looking at different generation technologies.

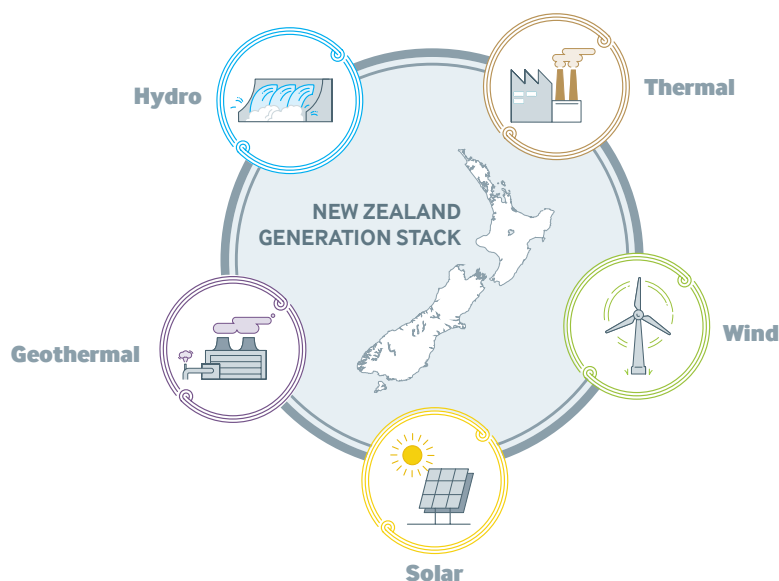


Figure 15: The generation stack update considered five different generation technologies

Thermal generation

Thermal generation such as coal and gas-fired generation totals around 2.4 GW in New Zealand's current generation fleet. The existing plant provides baseload generation (approximately 1.8 GW), peaking generation (approximately 600 MW) and dry year reserve. A net zero carbon future implies a move away from such thermal generation toward lower carbon alternatives. Our assumptions in regard to existing thermal plant retirements is:

| Generation plant | Retirement | Reason |
|-------------------------|---------------------|-----------------------|
| Huntly Rankine units | 2023-30 as economic | Published information |
| Huntly Rankine units | No coal after 2025 | Published information |
| Taranaki combined cycle | 2025 | Published information |

Table 5: Existing thermal generation retirement assumptions. Beyond these assumptions, we assume plants retire when they reach their project lifetime, as given in the 2020 Thermal Generation Stack Update Report (WSP).

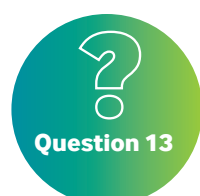
100% renewable generation targets

Our scenarios do not exclude new gas-fired generation being built in the future, particularly for peaking purposes. In part this ensures the generation expansion model can find a feasible new generation mix, but allowing the model to build new gas generation if economic, also demonstrates whether 100% renewable generation mixes are more or less economic. The generation stack also includes gas plants with carbon sequestration (very low carbon emissions) which can operate as baseload and the model can choose to build this generation if economic.

We could force the model to achieve a renewables generation target, but this would be better treated as a sensitivity, rather than being a variation across scenarios.

Gas price and availability

Our modelling reflects a flat gas price of \$6.19/GJ, the same as reflected in EDGS 2019. We also assume limited gas availability until 2050.



Question 13

Are our assumptions about gas price and availability reasonable?

Hydro generation

The hydro generation stack includes new potential generation in the North and South Island, but predominantly in the South Island, as shown below




| | |
|---|--|
|  New hydro resource: | Power 1,700 MW Energy 8,195 GWh |
| Resource location:  | Waitaki, Clutha and other SI rivers (primarily) |
|  Implications for grid: | Grid back bone HVDC link |

Figure 16: Potential new hydro resources in New Zealand

The buildability of this potential new generation is questionable, given environmental implications, but it is interesting to note that the generation expansion model finds these projects attractive and tends to always build them. The energy from hydro generation is relatively low cost and hydro generation is useful as both energy supply generation and peak supply generation (for balancing intermittent generation sources such as wind and solar).

Geothermal generation

The geothermal generation stack includes new potential generation in both the Northland and Taupo/Bay of Plenty region, but predominantly in the Taupo/Bay of Plenty region, as shown in Figure 17.

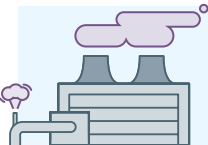


| | |
|---|--|
|  New geothermal resource: | Power 1,035 MW Energy 8,613 GWh |
| Resource location:  | Taupo volcanic zone (primarily) |
|  Implications for grid: | Central NI and grid back bone |

Figure 17: Potential new geothermal resources in New Zealand

The generation stack information for new geothermal projects indicates that the capital cost of building such generation is high. At the costs indicated in the latest generation stack information, new geothermal generation is not built by the generation expansion model.

These capital costs have increased significantly since the 2011 generation stack information was produced. The availability of new geothermal is diminishing and it is more expensive to access the remaining resource, which is reflected in the new generation stack information. Using the 2011 capital costs, new geothermal generation is always built as it is reasonable cost baseload generation. The new generation stack information is realistic, however we also understand that geothermal generation projects typically produce waste heat which has a value and is often utilised for other purposes. If the value of the waste heat is taken into account, the cost of the electricity generation reduces, but that is difficult to assess. Overall, we believe the generation stack information exaggerates the likely cost of new geothermal generation and it will be economic to build at least a portion of the 1035 MW available.

Solar generation

The solar generation update focussed on the economics and location of grid-scale solar plants. It did not consider rooftop domestic or commercial solar PV, as this is assessed elsewhere.

A comprehensive evaluation of locations was considered, for a range of future wholesale electricity prices. The generation stack identifies a significant potential for new grid-scale solar generation, depending upon future wholesale prices.

As seen in Figure 18, the location of future solar generation is widely distributed.

We have included a long list of potential plants on our generation stack, leaving it to the generation expansion model to decide whether it is economic at the cost provided.

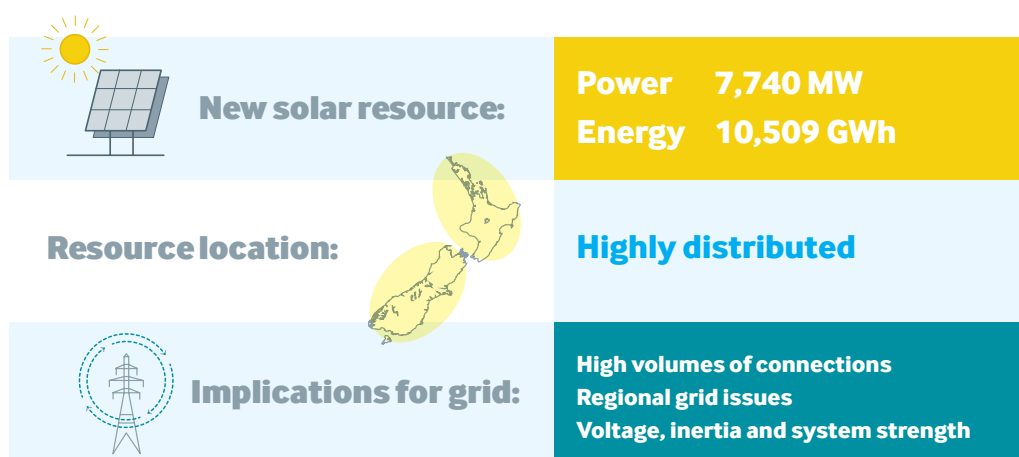


Figure 18: Potential new solar resource in New Zealand

Wind generation

Based on the generation stack information, wind generation is likely to play a significant part in New Zealand's future grid-connected generation mix. Wind resource is plentiful and the forecast cost of wind generation is decreasing.

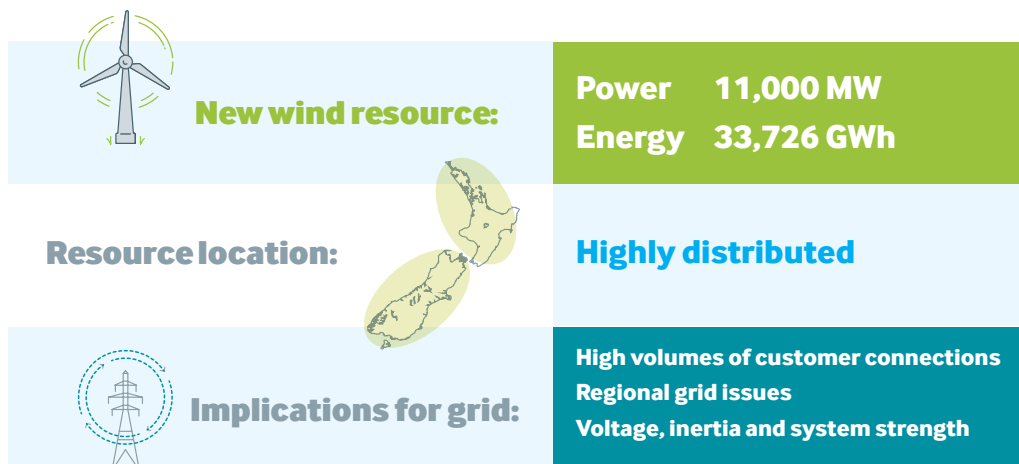


Figure 19: Potential new wind resource in New Zealand

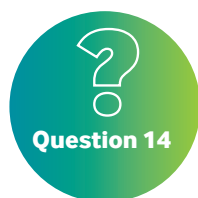
We have included potential new generation according to the information included in the MBIE generation stack update and it plays a significant part in all generation expansion plans.

We note that the generation expansion model also builds the firming generation (e.g. hydro) required to integrate new wind generation into the generation mix and provide a reliable supply of electricity.

At this point the generation stack does not include an alternative of installing battery storage with new wind generation, as we have no information on such options, but this would be an interesting comparison.

Grid-scale batteries

Grid-scale batteries have been added to the generation stack. The model is offered 100 MW battery options at several locations around the country and we will allow the model to decide whether it is economic to build.



Should grid-scale batteries be included on the generation stack and is our approach of including 100 MW batteries at a range of locations appropriate?



Adding a pre-model to steer the technology mix for energy supply scenarios

Use of a pre-model

As discussed above, although least-cost generation expansion modelling is a reasonable approach it does ignore some real-world realities.

For instance, new hydro generation may be economic, but it has environmental downsides not reflected in the cost and its buildability is questionable.

Similarly, geothermal generation appears too expensive to build, yet has attractive characteristics in terms of the overall generation mix. The capital costs included on the generation stack are real, but do not reflect the offsetting costs from use of waste heat, which may reduce the electricity generation cost to be competitive with other technologies.

When determining appropriate energy supply scenarios, we could try to “adjust” the generation costs of various new generation technologies to achieve particular outcomes, but judgement is involved and it is difficult to justify the choices made.

Our preference and proposal is to introduce a new step into the generation expansion modelling process, which tends to steer the technology mix. Our proposal is that we include a minimum new generation build for particular technologies in each scenario. For instance, we can include a minimum hydro build in the hydro scenario, a minimum solar build in the solar scenario, etc.

This pre-modelling step acknowledges that a least-cost approach to generation expansion modelling is not perfect, it acknowledges the considerable uncertainty in the relative future costs of new generation technologies and importantly it provides diverse scenarios which are useful in our investigations. The transmission grid needs to be able to accommodate new generation, wherever it is built. The generation sources identified in the generation stack are quite different geographically and may result in quite different transmission grid needs. It is important our investigations explore the range of future possibilities.

What we are proposing is not unlike a what-if approach. What if the environmental difficulties for new hydro generation were eased? What would the generation expansion plan look like then? What if the cost of new solar generation falls much quicker than other technologies? What would the generation expansion plan look like then?

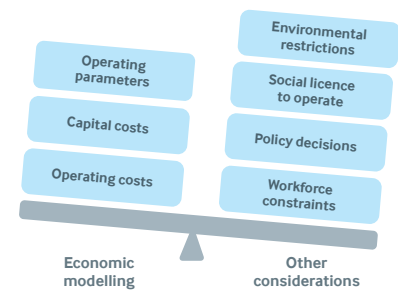
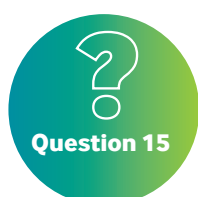


Figure 20: Balancing economic modelling with real world considerations



Figure 21: Proposed approach to include a pre-model step into developing energy supply scenarios



Question 15

Is our proposed approach whereby a pre-model is used to steer the technology mix in developing generation technology-biased supply scenarios reasonable?

Matrix of demand and energy supply scenarios

Using our proposal to develop energy supply scenarios based on generation technology biases, a question arises as to how to build combined demand and supply scenarios from the various matrix of possibilities:

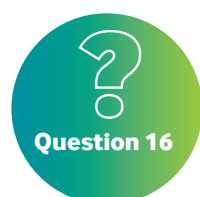
| | | Supply Side | | | |
|-----------------|---------------|-------------|-------|-------|------|
| | | Geothermal | Hydro | Solar | Wind |
| Demand Forecast | Disruptive | | | | |
| | Environmental | | | | |
| | Growth | | | | |
| | Reference | | | | |
| | Global | | | | |

Table 6: Matrix of possible demand and energy supply scenarios

The separate approaches used to develop our demand and energy supply scenarios does not lend itself to combining particular demand scenarios with particular energy supply scenarios very well. For instance, should the Reference demand scenario reflect a geothermal, hydro, wind or solar biased energy supply scenario? No single combination fits particularly well.

We propose not to associate a particular demand scenario with a particular energy supply scenario at this time. The choice of relevant scenario combinations depends upon the particular investigation being considered. If the investigation is considering transmission into the Bay of Plenty, for instance, then demand in Bay of Plenty and new generation either side of the transmission being investigated is relevant. In such a case it may be that there is considerable variation between the demand scenarios, but little or no variation between the energy supply scenarios. That may be a different situation to identifying the relevant scenarios for a HVDC investigation, say. In that case, demand in the North and South Islands, along with new generation in both islands is relevant. Hence, we propose not predefining scenario combinations now, but leaving that for each individual investigation.

For guidance, we discuss the principles we propose to apply to decide on the relevant combinations, below. As mentioned above, we propose that these principles would be applied and discussed in the long-listing document for each individual investigation.



Question 16

Is our proposed approach whereby a relevant mix of demand and energy supply scenarios is determined for each investigation reasonable?

Peak supply scenarios and dry year reserve supply scenarios

Peak supply possibilities and dry year reserve possibilities are different from energy supply possibilities.

We propose considering a range of possible solutions:

Distributed batteries – we are assuming a portion of the batteries included with rooftop solar PV and electric vehicles would be available to be used for peak shaving, but there is also the future possibility of grid connected batteries. Although none have yet been connected in New Zealand these are becoming increasingly common overseas and it does not seem unreasonable to assume they will appear in New Zealand in time.

Hydro – can be used for firming intermittent generation and meeting short-term demand peak issues, however, by definition is not useful for dry year reserve.

Thermal peaking plant – there are currently several gas-fired peaking plants in the North Island. These may remain in the generation mix, depending upon gas prices, new generation costs and government policy, or they may close.

Onslow – the government is considering the viability of building a large storage lake in the South Island which could be used for peak supply, or dry year reserve.

Renewable overbuild – an excess of new wind, solar and/or geothermal generation could be built, so that in dry hydrological years there is sufficient generation to provide a reliable supply of electricity.

Hydrogen – there are several possibilities for hydrogen use. One example would be where it is economic to overbuild generation to be available in dry hydrological years. In normal or wet hydrological years, that generation could be used to generate hydrogen, which could potentially be stored and used for peak supply or as an alternative dry year reserve supply. Another example is that hydrogen plants may be built for export hydrogen, powered by electricity from the grid. Such production may be flexible and able to ramp down considerably in a dry year.

Although peak supply and dry year reserve supply are different issues, we can see from Table 7 below, that there is a relationship between the solutions for both.

For instance, if Onslow is built, or the primary purpose of providing dry year reserve, it could also provide peak supply and it may be unlikely that it would be economic to build any other peaking solutions.

We have outlined the six most consistent options in Table 7.

| | | Peaking solution | | | | |
|-------------------|--------------------------------|----------------------------|-------|-------------------------|--------|----------|
| | | Distributed batteries (DR) | Hydro | Thermals (gas, biomass) | Onslow | Hydrogen |
| Dry year solution | Renewable overbuild | 1 | 2 | | | |
| | Thermal (gas storage, biomass) | | 3 | 4 | | |
| | Onslow | | | | 5 | |
| | Hydrogen | | | | | 6 |

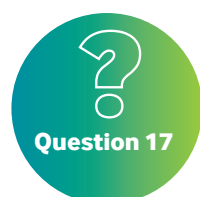
● Consistent
● Neutral
● Inconsistent

Table 7: Peaking and dry year solution combinations, the feasibility of a combination is indicated with a colour

These six possibilities would have very different transmission requirements. They are geographically diverse, with some being South Island based and some North Island based.

As with the energy supply scenarios, these six possibilities do not lend themselves to combining with particular demand scenarios very well.

As with the energy supply scenarios, we propose not to associate a particular demand scenario with a particular peak or dry year reserve scenario at this time. The choice of relevant scenario combinations depends upon the particular investigation being considered and we propose leaving each individual investigation to determine a relevant set of scenarios.



Is our proposed approach whereby a relevant mix of demand, energy supply and peak/dry year reserve supply scenarios is determined for each investigation reasonable?

Transmission Pricing Methodology

Transpower is currently developing a new Transmission Pricing Methodology (TPM) in accordance with the Electricity Authority's Guidelines. The new TPM introduces a benefit-based charge for interconnection investments. At this stage of the TPM's development, we currently envisage the scenarios used in major capex investigations (EDGS or reasonable variations) will be an input to pricing determinations under the standard method of the benefit-based charge.

The panel discussed whether development of the demand and supply scenarios should reflect the possible effects of a revised TPM. The conclusion was that, as the TPM is still being developed, it is not clear at this point what, if any, effects would need to be considered.

Choosing scenario combinations

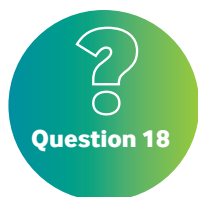
As described above, our draft EDGS 2019 variations is not a set of five demand and supply scenarios, as outlined in MBIE's document of July 2019.

Rather, we have five draft EDGS 2019 variations to the demand scenarios, four draft variations to the energy supply scenarios and six draft variations to the peak and dry year reserve supply scenarios, resulting in an overall potential one hundred and twenty possible scenarios.

We consider it impractical to consider this number of scenario combinations in our investigations. Although we must investigate a range of potential uncertainties in order to ensure our investment proposals are robust, we consider ten scenario combinations would be the maximum practical. Our preference would be to consider less, but given the unprecedented future uncertainties the electricity industry faces at the moment, we acknowledge the need to be thorough and to analyse a wide range of possible futures.

In order to determine a reasonable range of scenarios, we have developed some principles that will be applied in each investigation:

- Determine which energy supply scenarios might require different transmission options.
- All such energy supply scenarios should be included.
- Determine which peak supply and dry year reserve supply scenarios might require different transmission options
- Ensure a representative range of peak supply and dry year reserve supply scenarios is included.
- Determine whether any of the energy supply or peak supply, or dry year reserve supply scenarios match any of the scenario stories well.
- If they do, combine them into a single demand and supply scenario.
- If they do not, leave the demand and supply scenarios separate.
- Where the demand and supply scenarios are separate, determine which combinations may require significantly different transmission options and include all such combinations.
- The minimum number of scenarios to be analysed is five.
- For practical purposes, the maximum number to be analysed should be ten.



Is our proposed approach to determining the scenario combinations to be considered in investigations reasonable?
Are the principles we have developed reasonable?

Scenario weightings

In our analyses, we determine the costs and benefits of the short-listed options for each scenario separately. The net benefit for each option is benefits minus costs. We then calculate a weighted average net benefit, by applying a weighting, or probability to each scenario.

The default probability for each of the EDGS 2019 is 20%, implying the scenarios are equally weighted.

To determine our draft EDGS 2019 variations, we have adjusted some of the panel feedback in order to provide a diverse set of demand scenarios. Also, given the high level of uncertainty in regard to future generation, we have developed a matrix of possibilities only and are proposing to leave the formulation of an appropriate set of combined scenarios to individual investigations. In our view, this means that the combined scenarios may have different likelihoods and not be equally weighted.

The panel agrees with that view. We did not ask the panel to propose a weighting for individual scenarios, but we did ask whether some should be more or less likely than others. As a result, we are suggesting that the relative likelihoods may be as follows:

| Demand scenarios | Global | Reference | Growth | Environmental | Disruptive |
|-----------------------------------|--------|-----------|--------|---------------|------------|
| EDGS 2019 | 20% | 20% | 20% | 20% | 20% |
| Draft EDGS 2019 variations | ↓ | ↑ | ↓ | | ↑ |

Table 8: Indications of the relative scenario weightings

| Supply scenarios | Hydro | Geothermal | Wind | Solar |
|-----------------------------------|-------|------------|------|-------|
| Equal weighting | 25% | 25% | 25% | 25% |
| Draft EDGS 2019 variations | ↓ | | ↑ | |

Table 9: Indications of the relative supply scenario weightings

| Peak and dry year reserve supply scenarios | Batteries/overbuild | Hydro/overbuild | Hydro/thermals | Thermals | Onslow | Hydrogen |
|--|---------------------|-----------------|----------------|----------|--------|----------|
| Equal weighting | 17% | 17% | 17% | 17% | 17% | 17% |
| Draft EDGS 2019 variations | | | | | | |

Table 10: Peak and dry year reserve supply scenario weightings

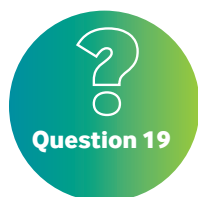
There is more uncertainty in regard to future peak/dry year scenarios than with either demand or supply scenarios. At this stage we have no basis for not equally weighting the possibilities.

We are not proposing any more exact weightings at this time, but will leave that to each investigation, once the appropriate scenario combinations have been determined. The scenario combinations and weightings will be consulted on as a part of each investigation. We note that assigning weightings is a subjective exercise and may be contentious. For that reason, we suggest that “likelihood bands” only be used and our proposal is as follows:

| Likelihood band | Likelihood | Scenario weighting |
|-----------------|------------|--------------------|
| A | 0-20% | 10% |
| B | 10-30% | 20% |
| C | 20-40% | 30% |

Using this approach each scenario combination would be classified as A, B or C and assigned either a 10%, 20% or 30% weighting accordingly. This approach recognises that some scenarios are less or more likely, but minimises subjective discussions by pre-assigning the related weighting. Where the sum of the weightings does not equal 100%, we propose the scenario weightings are scaled so that the sum does equal 100%.

The bands above assume five scenarios are used. Different bands would be required where different numbers of scenarios are used.



Is it reasonable to assume that our EDGS 2019 variations may not be equally weighted?

Is our proposed approach to dealing with unequal weightings reasonable?



Summary of specific questions

| Question | Report page reference | |
|----------|-----------------------|--|
| 1 | p9 | Do you agree that EDGS 2019 need to be reviewed for the purposes of our ASILR and NZGP projects? |
| 2 | p11 | Is it reasonable to consider the demand and supply scenarios separately? |
| 3 | p12 | Are our assumptions in regard to Tiwai closure reasonable: a) Tiwai will close August 2024 b) We will include August 2021 and August 2026 as potential sensitivities c) Tiwai closure will not be phased. It will fully close on the assumed closure date |
| 4 | p15 | Are our assumptions in regard to the effect COVID-19 may have on electricity demand reasonable? |
| 5 | p16 | Are our base demand growth assumptions reasonable variations of the EDGS 2019 assumptions? |
| 6 | p17 | Are our proposed industrial energy demand variations reasonable: <ul style="list-style-type: none"> A reduction of 567 GWh (approximately 20%) in existing industrial demand in the Global and Environmental scenarios The inclusion of two sensitivities for new industrial load at Tiwai and in Auckland, to be considered as relevant in our analyses. |
| 7 | p19 | Are our proposed process heat electrification demand variations, as shown in Figure 5 reasonable? |
| 8 | p18 | Are our proposed electric vehicle energy demand variations, as shown in Figure 6, reasonable? |
| 9 | p20 | Are our proposed rooftop solar PV variations, as shown in 7, reasonable? |
| 10 | p22 | Are our proposed EDGS 2019 variations for energy demand reasonable? |
| 11 | p23 | Are our assumptions re the level of "smartness" available for peak demand shaving reasonable? |
| 12 | p28 | Are our draft peak demand EDGS 2019 variations reasonable? |
| 13 | p29 | Are our assumptions about gas price and availability reasonable? |
| 14 | p35 | Should grid-scale batteries be included on the generation stack and is our approach of including 100 MW batteries at a range of locations appropriate? |
| 15 | p36 | Is our proposed approach whereby a pre-model is used to steer the technology mix in developing generation technology-biased supply scenarios reasonable? |
| 16 | p37 | Is our proposed approach whereby a relevant mix of demand and energy supply scenarios is determined for each investigation reasonable? |
| 17 | p39 | Is our proposed approach whereby a relevant mix of demand, energy supply and peak/dry year reserve supply scenarios is determined for each investigation reasonable? |
| 18 | p40 | Is our proposed approach to determining the scenario combinations to be considered in investigations reasonable? Are the principles we have developed reasonable? |
| 19 | p42 | Is it reasonable to assume that our EDGS 2019 variations are no longer equally weighted? Is our proposed approach to dealing with unequal weightings reasonable? |

Table 12: Summary of specific questions

How to make a submission

This consultation is open until 5:00pm, Friday, 26 February 2021.

Submissions should be emailed to demandforecasting@transpower.co.nz using the heading "Draft EDGS 2019 variations consultation".

Submitters may comment on any relevant aspect of our topic.

We have asked some specific questions, which are summarised in Table 12 and we welcome submissions on those questions, but all relevant comments are welcome.

Submissions will be posted on our website and be public. If any aspect of your submission is confidential, please advise us and we will not publish that part of the submission.

If there is any aspect of your submission that is confidential, please:

- clearly inform us of the sections you consider confidential and indicate why
- indicate whether we can share the confidential information with the Commerce Commission.

Transparency is important in this process and we may not be able to rely on confidential information to justify an investment proposal.

