THE FUTURE IS ELECTRIC

A Decarbonisation Roadmap for New Zealand's Electricity Sector

BOSTON CONSULTING GROUP

Contents

Disclaimer

Boston Consulting Group (BCG) was commissioned to write this independent report on behalf of several participants across the electricity sector, comprising generators, distributors, and retailers.[1]

Concept Consulting conducted the quantitative modelling of pathways used in this report. BCG has drawn on this modelling, together with other data sources, to produce the resulting insights, conclusions, and recommendations.

RSM has provided probity assistance to ensure that the report is held to the highest standard of independence and integrity. This includes attending meetings between BCG and sector participants and confirming that changes made to the draft report are based on facts and not subjective interpretation. Russell McVeagh has provided compliance assistance to ensure appropriate information barriers and confidentiality requirements have been observed between sector participants in the provision of information to BCG.

1. Sector participants that commissioned this independent report include Contact Energy, Genesis Energy, Mercury, Meridian Energy, Vector, Unison Networks, Powerco, Wellington Electricity, and Orion. Manawa Energy, Lodestone Energy, Eastland, Nova Energy, Transpower, and Copenhagen Infrastructure Partners provided data but otherwise were not involved in the commissioning of this report.

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Purpose and scope of this report

This report presents a holistic view of Aotearoa New Zealand's electricity sector today and how the sector can evolve to best contribute to the country's decarbonisation objectives. This holistic view is critical to ensuring the sector makes the greatest possible contribution to emissions reduction while maintaining affordable and reliable electricity for all New Zealanders.

In this report, we evaluate potential pathways for the sector and answer fundamental questions about New Zealand's future energy system to identify a preferred pathway. We detail a roadmap and recommendations for the sector to achieve this pathway.

We have considered the entire electricity value chain (generation, transmission, distribution, retail, and behind-the-meter) in an impartial way. The resulting roadmap and recommendations represent the best contribution the sector can make to New Zealand's decarbonisation, not what is best for a given sector participant. Sector participants have contributed to this report by providing and fact-checking data, but we have developed the analysis and recommendations independently (see disclaimer on previous page).

This report covers the existing electricity value chain as well as adjacent electrifiable sectors. We have only discussed broader energy considerations when they have a direct bearing on the electricity market. This report does not delve into highly improbable shifts to the electricity market, nor does it assign roles and responsibilities for implementing recommendations.

Author's note

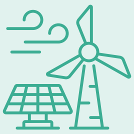
A list of technical terms and abbreviations are provided in the glossary at the end of this report.

All dollar figures are in real terms (i.e., inflation has been taken into account of) and New Zealand dollars, unless indicated otherwise.

2 Summary of the electricity transition under our roadmap

The electricity sector can enable rapid decarbonisation of the energy system.

The 2020s will be a critical decade for the electricity sector and New Zealand's transition to net zero carbon. With decisive, early action supported by the right policy, regulatory, and market settings, the electricity system can:



By 2030
Transition to 98% renewables and kick-start electrification, reducing New Zealand emissions by 8.7 Mt CO_2-e per year

By 2050
Enable rapid electrification of transport and heating, reducing New Zealand emissions by 22.2 Mt CO_2-e per year

This roadmap leads to faster and greater emissions reductions from the electricity sector than outlined by the Climate Change Commission (CCC).[2] If it is adopted, it would signal the sector's dedication to the rapid and deep decarbonisation of New Zealand's energy system.

These exciting outcomes are within reach for New Zealand – but only if action is taken at pace.

It will require unprecedented investment across generation, storage and networks but will lead to flat household electricity bills and declining household energy bills.

Deep, rapid decarbonisation at the lowest cost to consumers relies on a swift build of renewable generation. It will see demand peaks and dry years (when less hydroelectric generation is available) supported by batteries, demand response, some renewable generation overbuild (building more wind and solar generation than is ordinarily needed), and a small amount of fossil fuel generation (2% of total generation) in 2030. It will require an investment of $42 billion in the 2020s, including increased spend across generation, transmission, and distribution.

Modelling shows that this investment can be supported with slight increases in electricity unit prices while continued energy efficiency improvements help household electricity bills (excluding electric vehicles) remain flat. The energy transition will ultimately lead to lower average household energy bills – around 10% lower in 2030 and 45% lower in 2050 – as consumers benefit from significant fuel savings due to the electrification of transport.

To deliver this future, the electricity system will undergo a rapid transformation, starting in the 2020s.

In the 2020s, the system will transition from one that consists of primarily baseload, mid-merit and flexible resources to one that comprises mostly intermittent and flexible resources. As more intermittent generation enters the electricity system and over 95% renewables is achieved, the value of slow-start thermal power plants for meeting peak demand will decline significantly. This results in North Island peaks becoming increasingly difficult to meet, but the greater energy provided from new renewable generation will assist with alleviating dry year risk. These factors result in an increasing need for faster, more responsive flexible supply-side and demand-side resources.

Additional faster, more flexible resources that could provide the required flexibility this decade include batteries, open cycle gas turbines (OCGT) and dynamic demand response. Today, however, batteries are not yet economic enough to be deployed on a very large scale and there is carbon risk associated with investing in new gas generation. Smart system enablers, like automation and artificial intelligence (AI), are also only emerging in networks. As we transition to broad-based, near real-time, highly automated system flexibility in the 2030s, networks may need to rely on more manual, targeted means of flexibility in the 2020s.

There are several challenges, but none are insurmountable. Policy, regulatory, and market reforms will be required to enable the transition this decade.

From 2030, the transition will likely become easier as the cost of technologies like lithium-ion batteries, long-duration storage, zero-emissions generation and smart system enablers decline in the 2020s. With this storage and smarts, the system will become less reliant on fossil fuels to meet peaks and dry years. Electricity networks, particularly distribution networks, will also benefit from this increased system flexibility, allowing them to better manage complex, multi-directional power flows that will emerge on their networks.

Aotearoa New Zealand has a world-leading electricity sector, but slow reform will significantly jeopardise this position. **Timely, meaningful reform could lead to a system of almost 100% renewables by 2030 that delivers more affordable household energy than today.**

This report outlines what the electricity sector needs to do to deliver this transition, and the required policy, regulatory, and market settings required to drive this change.

2 Climate Change Commission, *Ināia Tonu Nei*, 2021

3 This report at a glance

3.1 Executive summary

New Zealand's energy system is one of the best in the world. It is ranked 9th in the world and 1st in Asia for its combined equity, security, and sustainability.[3] New Zealand's high share of renewable electricity (82%) is a major contributor to this performance, enabling New Zealand to affordably generate a low level of emissions and be resilient to global energy shocks.

New Zealand's electricity sector can improve this ranking by playing a major role in decarbonising the broader energy sector, improving energy affordability, and increasing energy independence. Despite this high share of renewable electricity, only 28% of New Zealand's total energy consumption is from renewable sources. Roughly 30% of New Zealand's gross emissions come from sources that can be decarbonised by the electricity sector. By powering these sources with renewable electricity, household energy bills could decline by 10% by 2030 and 45% by 2050. New Zealand's reliance on foreign oil imports will also decline substantially as transport is electrified, increasing energy independence and resilience to global energy shocks.

Electrifying transport and heat, and increasing renewable electricity, will be the most significant contributors to New Zealand achieving net zero carbon by 2050, delivering an estimated 70%, or 22.2 Mt CO_2-e per year, of the gross emissions reductions required to achieve New Zealand's net zero carbon target by 2050.

This increased electrification and renewable electricity will also kick-start the energy sector's decarbonisation journey to 2030. Our modelling shows that it makes economic sense for New Zealand to reach 98% renewable electricity by 2030. This, combined with accelerating electrification of transport and heat, will deliver 8.7 Mt CO_2-e of emissions reductions in 2030, equivalent to a 27% reduction in energy emissions over the next 8 years.

This represents faster and greater emissions reductions from the electricity sector than outlined by the Climate Change Commission.

Delivering this future will require an unprecedented investment of $42 billion in the 2020s, including:

- **$10.2 billion**
  in 4.8 GW of new utility-scale renewable generation capacity – more than a 50% increase on installed capacity in the system today.
- **$1.9 billion**
  in new flexible generation and demand resources to cater for peak demand periods and dry years. This represents 4 times the supply-side flexible capacity that was developed in the 2010s.
- **$8.2 billion**
  in transmission infrastructure to enable new renewable and flexible generation. Investments in key projects like Central North Island, Wairakei Ring and an additional HVDC cable will be critical.
- **$22 billion**
  in distribution infrastructure to enable electrification in the 2020s and prepare networks for rapid electrification and multi-directional flows of electricity in the 2030s. Total investment need in 2026–2030 is forecast to be 30% higher than 2021–2025.

A significant increase in skilled workforce across the electricity value chain is required to deliver this investment.

3 World Energy Council, Trilemma Index, 2021

3.2 Future challenges facing the electricity sector

Decarbonisation poses challenges for the electricity sector, but none are insurmountable. To date, New Zealand's electricity sector has maintained reliable and affordable electricity while reducing emissions.

The electricity sector's significant contribution to New Zealand's emission reduction journey relies on 4 conditions:

1. New **renewable generation** at a sufficient pace
2. Sufficient flexible demand and generation capacity to meet increasing **peak demand**
3. Sufficient flexible demand and generation energy to meet **dry year** energy needs when less hydroelectric generation is available
4. Sufficient **network** infrastructure (including smart virtual infrastructure) to meet new electrification demand, connect new renewable generation sources, and provide flexible network capacity

3.3 Our preferred pathway

We assessed multiple decarbonisation pathways to deliver these conditions. The preferred pathway, Smart System Evolution, encourages a smart whole-of-system transition, deploying a range of technologies including batteries, distributed energy, and demand response. It ensures emissions reductions comparable to a 100% renewable electricity scenario, the lowest total system cost, the most affordable household energy bills, and reliable electricity supply. It also achieves 98% renewable electricity by 2030 and retains optionality to strive for 100% renewables beyond 2030 – existing thermal plants can be retrofitted for green fuels or replaced by other storage technologies.

By 2030, this pathway saves $1.9 billion in total system costs, reduces average annual household bills by $70, and reduces emissions by an additional 205 kt CO_2-e, relative to a business-as-usual pathway.

3.4 Implications for the sector

1 Electrification supports decarbonisation, affordability and energy independence

2 Smarter, more flexible system saves $10 billion to 2050

3 Ahead of time investment needed for networks

4 Large scale pumped hydro has some advantages but also drawbacks

5 A hard 100% renewable electricity target will lead to sub-optimal outcomes

6 Fossil-fuel power stations have a role to play but reliance on them will decrease

7 Hydrogen export facility could provide valuable demand-side flexibility

8 Electricity and biomass likely to displace reticulated gas through time

9 Implementing a suite of low cost solutions will maintain optionality

Our assessment of the various pathways for the electricity sector also generated critical insights:

1. **Electrification will support decarbonisation, improve household energy bills, and increase the resilience of New Zealand's energy system.** It will remove 18.4 tonnes CO_2-e per year by 2050. It is forecast to substantially reduce average (mean) household energy bills by about 10% in 2030 and 45% in 2050. It will also improve New Zealand's energy independence, increasing energy supplied from domestic production from 55% today to 85–90% in 2050.
2. **A smarter, more flexible electricity system will save around $10 billion on an NPV basis to 2050,** incorporating demand response, smart electric vehicle (EV) charging, and distributed energy resources. Investment in new technologies like distribution network visibility and coordination will unlock many of these measures, enabling at least 2 GW of demand-side flexibility by 2030 and 5.8 GW of demand-side flexibility by 2050.
3. **Today's just-in-time approach to transmission and distribution network investment won't be suitable for the expected rapid electrification and renewable generation development.** The existing regulatory system supports just-in-time investment decisions in a relatively stable environment, waiting as late as possible to achieve confidence before each increment of investment. However, with rapid electrification and renewable generation development on the horizon, a significant increase in network investment is needed under conditions of higher uncertainty, ahead of time. Late investment will stall low-cost renewable generation development and electrification, increasing emissions and net prices for consumers.

4. **The Lake Onslow pumped hydro project has several advantages as well as some drawbacks.** Lake Onslow would provide 5,000 GWh of low carbon inter-year storage to support security and 100% renewable electricity in all hydrological years. Lake Onslow can provide real-time system stability, peaking capacity, and dry year support – making it an all-round flexible, renewable resource. Lake Onslow would also reduce the renewable overbuild needed to meet electricity needs in dry years and reduce the electricity market's reliance on gas.

   There are also some drawbacks, including cost, and its location in the South Island being less suited to meeting North Island peaks. The Government's $80 million investigation into Lake Onslow will provide improved information on the project, including greater details on the cost, timeline to build, generation capacity, lake storage, how Lake Onslow will operate in the market, and other aspects like consenting. Until these details emerge it is too early to develop a strong view on its viability.

5. **A hard 100% renewable electricity target will likely lead to sub-optimal outcomes. New Zealand is likely to achieve 98% renewable electricity by 2030 in the absence of a hard target.** The return on investment for achieving the additional 2% of renewable electricity will come at a marginal abatement cost of $340 to $2,000 per tonne of CO_2-e. Phasing out thermal generation entirely could also pose reliability and resilience risks and inhibit electrification due to the resulting higher prices, leading to lower overall emissions reductions. Closer to 2040, the cost to transition the electricity system from 98% to 100% renewable electricity is likely to be much lower as relevant technologies become significantly more affordable and new technologies emerge.

6. **Fossil fuel power stations have a role to play through the transition but our reliance on them will reduce substantially through time.** As we transition, gas will still likely be needed to support the system during dry years. Dry years will remain a critical issue but will be alleviated by new solar and wind generation. Gas will also support in extenuating peak circumstances over the next decade. In the 2030s and beyond, the need for fast response, flexible generation, and demand capacity will be increasingly addressed due to declining costs of storage technologies and smart demand response. As the requirement for thermal peaking generation and capacity declines from 2030, there is the potential to use biofuels instead of natural gas near 2040, achieving 100% renewable electricity and further reducing greenhouse gas emissions from electricity generation.

7. **A hydrogen export facility could provide valuable demand-side flexibility but would only be effective if the unit economics of producing hydrogen in New Zealand stack up.** A facility in New Zealand (whereby most of the hydrogen is exported) could reduce wholesale electricity sector costs by $50 million per year. Economically, the facility could add $400–600 million GDP per year to the New Zealand economy and 4,100–7,200 jobs. The value to the grid of providing demand-side flexibility could be a negative for hydrogen customers internationally: the production would likely be exported to Japan and South Korea where reliability and regularity of supply would likely be valued. This may require either storage or contractual solutions.

8. **Electricity and biomass will likely displace gas for low- and medium-temperature processes; hydrogen is unlikely to be an economic alternative to gas in pipelines.** Electricity is cleaner and cheaper than coal or gas for low-temperature processes, and a lower cost and easier way to decarbonise gas than hydrogen. However, there are some use cases like steel production and very heavy transport where hydrogen is likely to be the most suitable decarbonisation fuel.

9. **A suite of low-cost solutions that maintain optionality is required to meet New Zealand's system stability, peak capacity, and dry year energy needs, and support an electricity sector comprised of more than 98% renewables.** To achieve New Zealand's emissions reduction objectives, we need a suite of solutions. As we transition away from fossil fuels, different solutions will provide different services (real-time, peaking, and dry year) across varying time durations at the most effective cost. The solutions will continue to evolve as technology improves – so maintaining optionality will support a lower cost transition.

3.5 Roadmap to deliver a successful transition

This report provides a roadmap to deliver the preferred pathway and the best outcomes for New Zealand:

	Summary	Electrification enablers
2020s	• Rapidly build renewable generation to reach 98% renewable electricity; phase out coal • Ramp up electrification supported by targeted thermal gen., demand flexibility and storage	• Rapidly electrify light vehicle fleet • 1 million EVs by 2030 • Commence large-scale transition of low/med temp. heat to electrification and biomass
2030s	• Turbocharge electrification through a continued fast build of renewable electricity • Develop new flexible renewables, storage options and a highly automated demand-side	• Phase out ICE vehicles; transition heavy vehicles to electric/hydrogen • 2.4 million EVs by 2040 • Transition low and medium temp. processes
2040s	• Continue electrification at pace to support close to full decarbonisation of key sectors • Significantly scale up batteries and embrace new smart demand technologies	• Electrify almost all land transport • 4.3 million EVs by 2050 • Scale up elec./hydrogen for high temp. processes; phase out fossil fuels in buildings

	Additional capacity	Additional generation	% renewable electricity
2020s	4.8 GW	10.6 TWh	98 %
2030s	5.3 GW	10.8 TWh	99 %
2040s	5.0 GW	12.8 TWh	99 % (Option to achieve 100% at low cost)

	Additional peak demand needs: Supply-side flexibility (peakers, storage)	Additional peak demand needs: Demand-side flexibility (EVs, demand response)	End-of-decade dry year energy contribution
2020s	1.1 GW	2.0 GW	7.6 TWh
2030s	0.8 GW	1.7 GW	8.7 TWh
2040s	1.2 GW	2.1 GW	9.4 TWh

	Transmission Investment	Distribution Investment	End-of-decade emissions abated by electricity sector (CO_2-e per year)
2020s	$8 billion	$22 billion	8.7 Mt
2030s	$10 billion	$25 billion	15.6 Mt
2040s	$11 billion	$24 billion	22.2 Mt

Source: Concept modelling, BCG analysis

We took a whole-of-electricity sector view of the work already underway and compared it with what needs to be done to achieve this roadmap. We found:

- **There is more than enough renewable energy generation in the project pipeline to achieve the roadmap's aim of 98% renewable generation by 2030.** There are 10.9 GW of new utility-scale renewables intended to be built against a need of 4.8 GW by 2030.
- **More flexible, supply-side resources may need to be added to the pipeline and this is likely to occur as storage costs improve.** To achieve peak demand by 2030, we need 1.1 GW of new supply-side peaking resources (OCGT or batteries) by 2030. There are 1.3 GW of resources in the pipeline but 1.1 GW of this is in early concept stage. It is likely that some early-stage projects will be developed, and new projects will emerge as the cost of storage declines rapidly.
- **The pipeline of flexible, demand-side resources is occurring at a sufficient pace to meet demand.** However, the pace of change required to enable a smart system is likely to accelerate over the 8 years and the sector will need to increase efforts by 2030.
- **There is sufficient flexible capacity and generation in the pipeline to meet dry year demand by 2030.** Around 60% of dry year need can be met by renewable overbuild. The remaining 40% can be met by gas or large-scale demand response. If renewable overbuild does not occur to the level identified, gas could cover dry year risk provided there is gas market flexibility. There are also several other potential dry year projects (e.g., Lake Onslow, Southern Green Hydrogen, and biomass trials at Huntly) underway which could provide dry year support.
- **There are plans to invest $22 billion in the 2020s in distribution infrastructure to support electrification and distributed energy resources.** This is a ~30% increase in spend in 2026–2030 relative to 2021–2025 and is sufficient for increased electrification provided it is supported by regulatory allowances. Smart network initiatives are occurring at a sufficient pace. However, the pace of change required to enable a smart system is likely to accelerate over the next 8 years and the sector will need to increase efforts to achieve what is needed by 2030.
- **There is sufficient transmission planned for increased renewable generation and electrification** under Transpower's Net Zero Grid Pathways program, however timely delivery of this will be critical.
- **Electrification of transport and process heat is increasing significantly – primarily due to the reformed emissions trading scheme (ETS), the Clean Car Discount and the GIDI fund.** Average monthly EV registrations have increased by ~5 times since the introduction of the Clean Car Discount, while over 50 industry decarbonisation projects have been co-funded under the GIDI fund.

3.6 Policy, market, and regulation recommendations to support the sector's decarbonisation

While on paper this progress and these intentions are positive, it is unlikely that the required activity will be delivered at the pace needed to achieve the preferred pathway. This is because:

1. In some instances, policy, regulatory and market settings do not provide incentives that align with these intentions – for example, providing smart flexibility in distribution networks will likely require improved funding mechanisms and allowances.
2. In some instances, policy, regulatory, and market settings may create barriers to deploying the required infrastructure – for example, the Resource Management Act (RMA) could inhibit the level of new renewable generation development required.

In absence of timely reform in these critical areas, we expect emissions reductions, affordability, and reliability of supply to be compromised.

To deliver the roadmap, New Zealand needs a policy, regulatory, and market environment that encourages and facilitates action from government and sector participants. These actions include:

1. **Support accelerated renewables development.** Ensure consenting frameworks enable rapid renewable development (**high priority**); develop mechanisms to mitigate supply chain risks, improve opportunities for Iwi investment that provide community benefits; and facilitate a deeper power purchase agreement (PPA) market.
2. **Encourage the right energy and capacity mix.** Assess and deploy market mechanisms to provide New Zealand with the assurance of both capacity and energy to manage peak demand and dry years, including:
   - **Recommended for implementation:** Deepen contract and derivatives markets, including for demand-side (**high priority**); implement an emergency reserve scheme; improve forecasting; improve tracking, monitoring, and visibility of markets and price formation; inflation index scarcity pricing; and inflation index the Customer Compensation Scheme charge.
   - **Recommended for investigation:** Assess an Operating Reserve Demand Curve to enable increased reserve cover (**high priority**); a 30-minute reserve service; a day-ahead market; a limited dispatch mandate; and a retailer reliability obligation.

3. **Scale transmission and distribution network investment.** Accelerate transmission development to enable renewable generation (**high priority**); scale distribution investment to enable electrification (high priority); and consider options for Renewable Energy Zones.

4. **Enable a smart electricity system.** Improve distribution peak pricing signals and smart managed tariffs (**high priority**); establish a roadmap for forming competitive flexibility markets (**high priority**); update regulatory frameworks to support virtual network investment including implementing totex funding (**high priority**); mandate default off-peak EV charging (**high priority**); and enable network investment in key aspects of orchestration, including visibility and operations.

5. **Drive decarbonisation through electrification.** Provide a roadmap from Clean Vehicle Standards to an ICE vehicle import ban; extend GIDI funding (if required); and improve the ETS in line with New Zealand's emissions targets.

6. **Implement this roadmap.** Deliver this whole-of-sector roadmap, coordinating with the National Energy Strategy (**high priority**); and implement a sector workforce development strategy.

New Zealand faces an exciting opportunity to build on the strong steps already taken and decarbonise the electricity sector. By working together and applying systems-thinking, the electricity sector can unlock a cleaner, greener, more equitable Aotearoa New Zealand.

Roadmap of priority recommendations in the 2020s

This report provides a roadmap for the implementation of the priority recommendations this decade

Support accelerated renewables development

2022-2025
- Ensure consenting frameworks enable rapid renewable deployment via RMA reform

2026-2030
- Continue to improve consenting frameworks to enable rapid renewable deployment

Encourage the right energy and capacity mix

2022-2025
- Progress work to deepen contract markets
- Progress investigations into mechanisms to extend reserves
- Implement an emergency reserve scheme
- Inflation index scarcity pricing and Customer Compensation Scheme

2026-2030
- Implement deepened contract markets
- Implement mechanisms to extend reserves
- Review efficacy of emergency reserve scheme
- Review price signals to assess sufficiency

Scale up transmission and distribution network investment

2022-2025
- Accelerate approvals and consenting for key enabling transmission projects
- Ensure distribution funding for 2026-30 is sufficient to enable electrification

2026-2030
- Deliver key enabling transmission projects
- Implement efficient distribution funding flexibility mechanisms to enable investment where unforeseen needs arise

Enable a smart electricity system

2022-2025
- Improve distribution peak pricing signals and smart managed tariffs
- Establish roadmap for formation of competitive flexibility markets
- Update regulatory frameworks to support virtual network investment
- Mandate default off peak electric vehicle charging

2026-2030
- Continue to improve distribution peak pricing signals and smart managed tariffs
- Implement roadmap for formation of competitive flexibility markets
- Implement TOTEX funding framework and new innovation mechanisms
- Increase network investment in orchestration, including visibility and operations

Drive decarbonisation through electrification

2022-2025
- Further strengthen ETS and policies to support transport and heat decarbonisation

2026-2030
- Establish ban on ICE vehicles from 2032-2035
- Extend and expand GIDI funding if required

Enable the implementation of this roadmap

2022-2025
- Develop joint industry statement of intent and action plan
- Implement roadmap and incorporate into National Energy Strategy

2026-2030
- Implement roadmap and continue to monitor progress
- Evolve and update roadmap as context evolves

4 The electricity sector is critical to achieving decarbonisation in New Zealand

This section provides an overview and context for New Zealand's energy transition and highlights the role that the electricity sector can play in New Zealand's energy system.

4.1 New Zealand's energy transition is unique

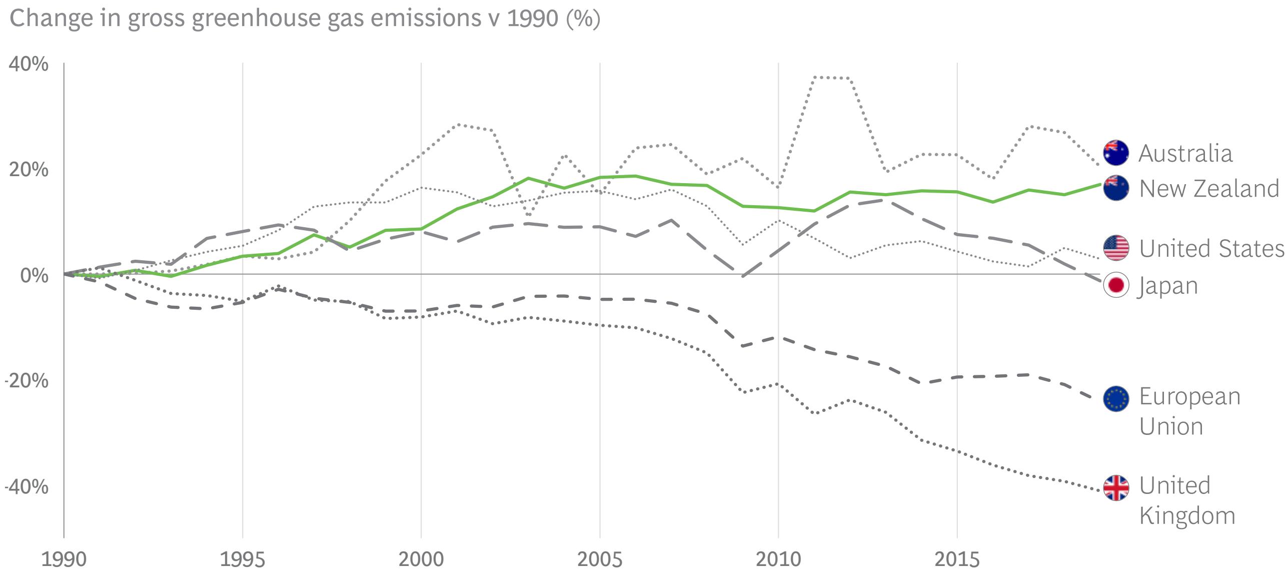
New Zealand's emissions profile is unlike that of any other country. It has one of the world's most renewable electricity sectors at 82% in 2021, but some of the highest emissions per capita in the world.[4] Agriculture plays a big part in these emissions – accounting for nearly half of New Zealand's gross greenhouse gas emissions, while electricity represents only 6% of emissions.[5] Other than agriculture, transport and heat are the major sources of emissions, representing 31% of New Zealand's gross emissions and 50% of emissions covered under the 2050 net zero carbon target (which excludes biogenic methane). By electrifying these 2 areas, leveraging its highly renewable electricity sector, New Zealand has a significant opportunity to decarbonise.

4.2 Emissions reductions are a priority for New Zealand

New Zealand, as with all countries, needs to play its role in the global transition to a net zero economy. With the 2nd highest level of emissions per GDP in the Organisation for Economic Co-operation and Development (OECD), New Zealand is lagging other developed economies (see Exhibit 1).[6]

The 2020s will be a critical decade for the electricity sector to change the emissions trajectory and enable New Zealand's transition to net zero carbon. The sector appears to strongly support the country's climate change objectives.

Exhibit 1: New Zealand's gross emissions have increased by 17% since 1990



Source: The World Bank

4 Worldometer, CO_2 Emissions per Capita, 2022

5 Climate Change Commission, Ināia Tonu Nei, 2021

6 OECD, Environmental pressures rising in New Zealand, 2017

In a 2021 letter to the Prime Minister and Ministers of Energy and Resources, the Environment and Climate Change, 11 of the largest electricity sector participants sector wrote:

> We recognise and fully support the urgent need to take bold action to achieve the goal of net zero carbon emissions by 2050. The delivery of secure, affordable, and low carbon energy is critical for a successful transition, and we want to support this outcome for Aotearoa New Zealand.[7]

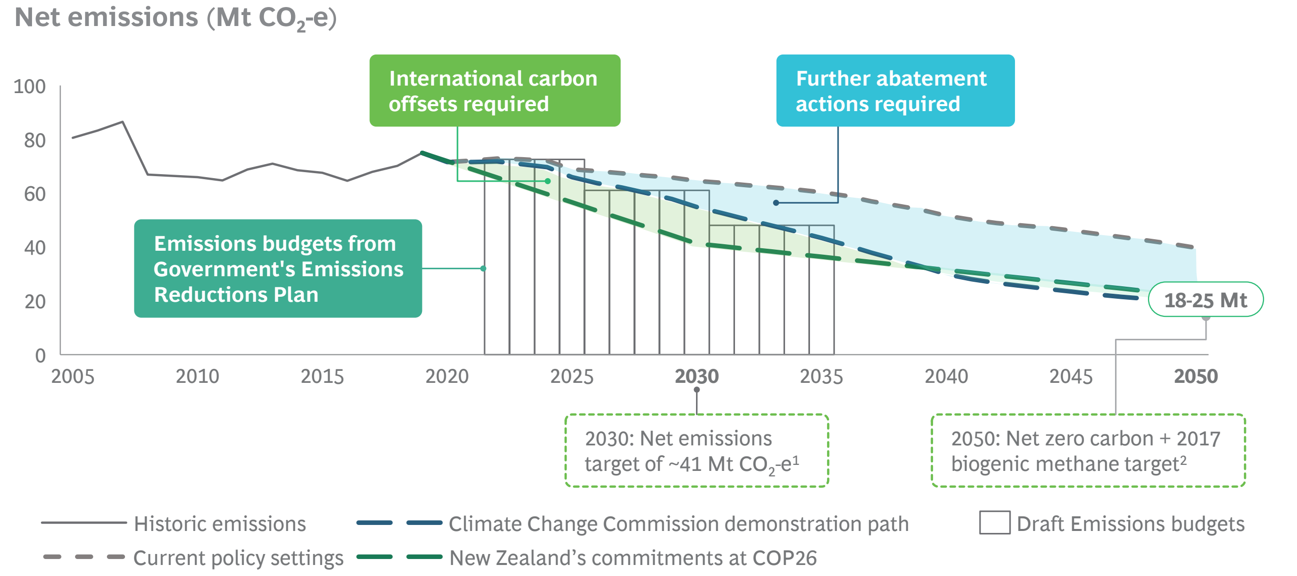
New Zealand has 2 main legislated emissions targets:

By 2030, a 50% reduction in net greenhouse gas emissions below gross 2005 levels
10% reduction in biogenic methane emissions below 2017 levels by 2030

By 2050, net zero carbon excluding biogenic methane
24–47% reduction in biogenic methane emissions below 2017 levels by 2050

The Government recently released its first emissions budgets and Emissions Reduction Plan, which aim to ensure these targets can be met (see Exhibit 2).

Exhibit 2: New Zealand's emissions commitments



1. 50% of New Zealand's gross emissions in 2005 (82 Mt CO_2-e) 2. 24-47% reduction on 2017 levels

Note: New Zealand has committed to reducing biogenic methane to 24-47% below 2017 levels (33.5 Mt CO_2-e), 21.6 Mt CO_2-e is midpoint of 24-47% reduction

Source: Climate Change Commission, Ministry for the Environment

7 Contact Energy, Genesis Energy, IEGA, Meridian Energy, Mercury, Orion, Powerco, Transpower, Trustpower, Unison, and Vector, Backing the transition to a thriving low carbon economy for Aotearoa New Zealand, 2021

4.3 The electricity sector, via electrification and renewable generation, will deliver more emissions reductions than any other sector

Although 82% of New Zealand's electricity is renewable today, only 28% of the country's total energy consumption is met by renewable sources. A large proportion of this non-renewable energy is oil (petrol and diesel) used for transport. Estimates are that the proportion of energy derived from renewable sources will need to be ~50% by 2035 and ~80% by 2050 to reach emissions targets.[8]

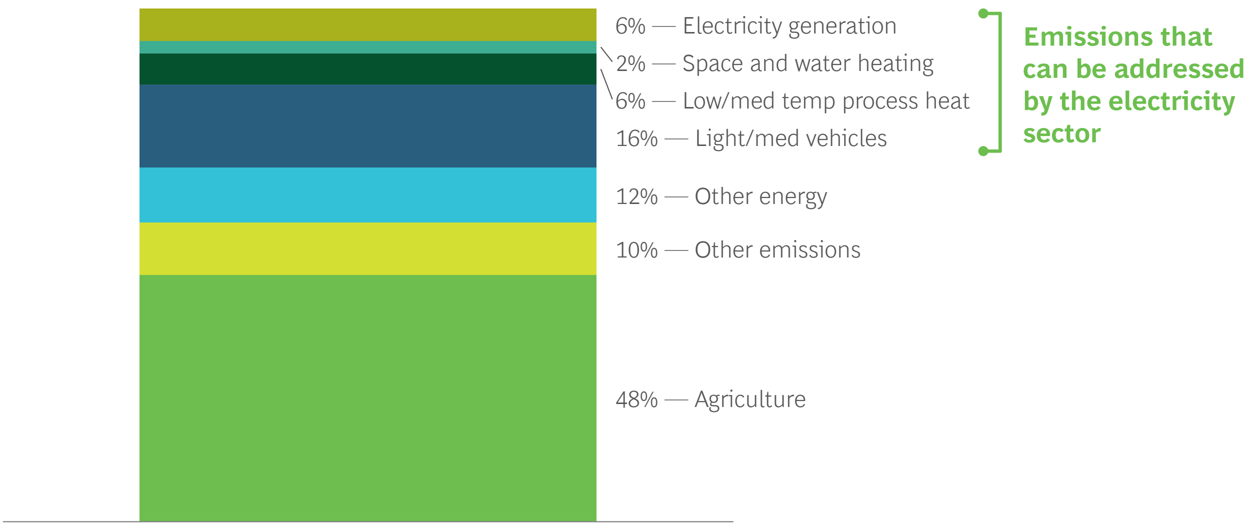
While every part of the economy must contribute to New Zealand's decarbonisation objectives, the electricity sector can play a critical and substantive role throughout the 2020s across 3 measures:

- Electrifying transport
- Electrifying process heat, and space and water heating in buildings
- Increasing the proportion of electricity provided by renewable resources

With these 3 measures, the electricity sector can reduce emissions from sectors that account for up to 30% of gross emissions, equivalent to ~50% of emissions covered under New Zealand's net zero target (a target which excludes biogenic methane), from 2019 levels by 2050 (see Exhibit 3).

Exhibit 3: **The electricity sector can directly support emissions reduction in activities accounting for ~30% of New Zealand's emissions**

New Zealand 2019 gross emissions (Mt CO_2-e)



Source: Climate Change Commission

8 Climate Change Commission, *Ināia Tonu Nei*, 2021

The electrification opportunity

At a glance: New Zealand's electrification opportunity

Sector	2019 energy emissions available for abatement (Mt CO_2-e)	% NZ 2019 gross emissions that could be abated	% NZ emissions covered under the net zero target (excludes biogenic methane)	Primary technologies
Ground transport	13.3 Mt	16.2%	25.7%	Electric vehicles for light transport, buses, light and medium trucks, and some heavy transport
Low to medium process heat	5.0 Mt	6.0%	9.7%	Electric heat pumps and electrode boilers
Heating space and water in buildings	2.0 Mt	2.4%	3.9%	Electric heat pumps
Total electrification potential	**20.3 Mt**	**24.6%**	**39.3%**	
Electricity generation emissions	5.1 Mt	6.2%	9.8%	Renewable electricity
Total sector potential	**25.4 Mt**	**30.8%**	**49.1%**	

This 30% of emissions come from ground transport (excluding heavy trucks and some rail), low-to-medium temperature heating processes, and heating for homes and business buildings, and can be easily electrified.

Even with New Zealand's current electricity mix, electrification represents a large emissions reduction opportunity. Concept Consulting estimates electrification could reduce New Zealand's baseline emissions by 4.8 Mt CO_2-e in 2030. Transpower's electrification roadmap estimated that accelerated electrification could reduce emissions by similar amounts: 2.7 Mt CO_2-e per year by 2030 (which excludes further abatement from electricity generation).[9] With more renewable electricity, this would increase to 4.7 MtCO_2-e per year by 2030.

In hard-to-abate areas such as heavy vehicle transport, it is unclear whether electrification or hydrogen will be the best solution. Even if hydrogen is the preferred technology for some heavy trucking, significant electricity will still be needed. For example, displacing 10% of New Zealand's petroleum product consumption (roughly equivalent to the share attributable to heavy vehicle transport) with locally sourced green hydrogen would require at least 10 TWh of electricity for electrolysis, equivalent to more than 20% of New Zealand's electricity consumption today.

9 Transpower, Electrification Roadmap, 2021

Exhibit 4: Renewable electricity to account for 58% of energy demand in 2050

	2020	2050
Total energy demand	677 TWh	407 TWh
Renewable electricity	19%	58%
Biomass and other	9%	23%
Coal[2]	8%	5%
Gas[2]	23%	4%
Oil	41%	10%

1. Demand in PJ is energy consumed, not primary energy. 2. Coal and gas numbers include electricity generation, converted from primary energy to the actual PJ electricity consumed

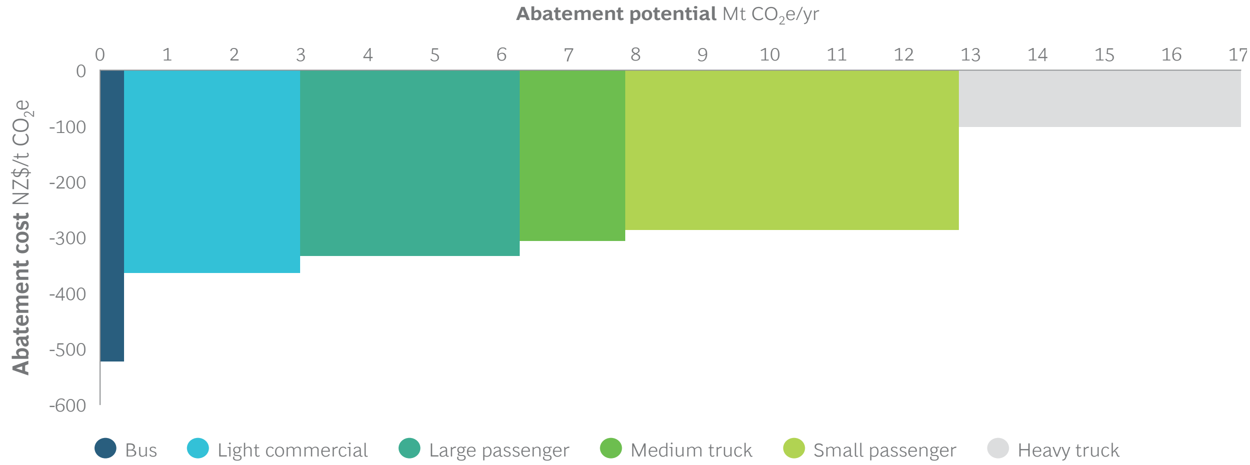
Source: Climate Change Commission, BCG analysis

Overall, the electrification opportunity is significant. CCC data and BCG analysis reveals that, from a base of 19% today, renewable electricity will make up 58% of our energy consumed in 2050 (see Exhibit 4). Alongside the rise of biomass (particularly in industry), most of New Zealand's energy needs will be met through domestically produced, low, or zero emissions fuels.[10]

Exhibit 4 highlights the impact that electricity has in reducing overall energy demand, due to its efficiency. Total energy demand will decrease by ~270 TWh, while energy demand for transport and industry will decrease by ~40 TWh and ~30 TWh respectively.

10 With 23% of New Zealand's 2050 energy needs met by biomass and other renewable fuels, renewable energy should surpass the 80% target proposed by the Climate Change Commission.

Exhibit 5: 2030 marginal abatement cost curve for transportation



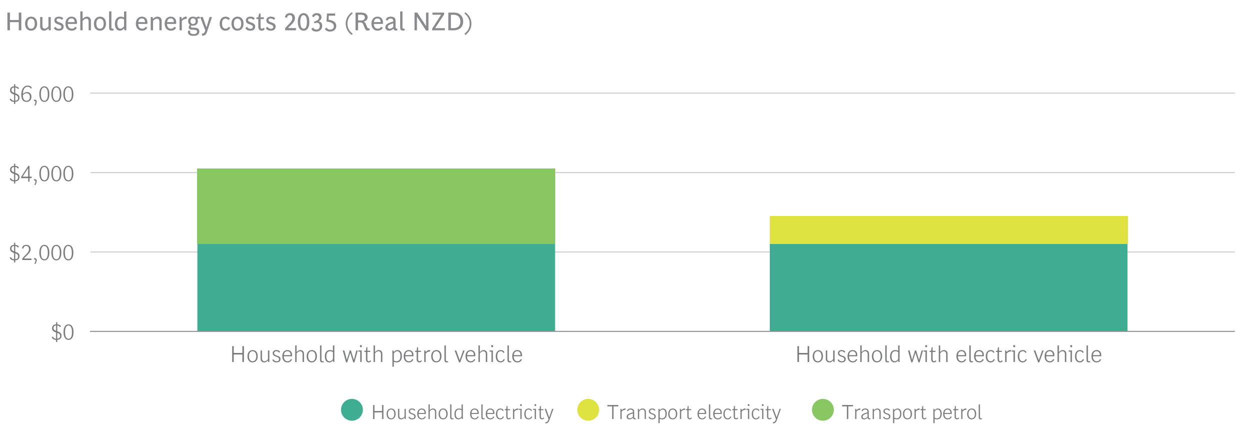
Source: Ministry for the Environment

Transport electrification

Electrification presents a well-established pathway to reducing the 20% of New Zealand's gross emissions (16 Mt) that come from transport today, with electric vehicle (EV) development and adoption accelerating globally. Road transport accounts for ~91% of New Zealand's transport emissions, with the remaining 9% attributable to aviation, rail, and marine where the role of direct electrification is less certain. For road transport, there is broad consensus that electrification is the path forward for most vehicles. The economics of electrification are most compelling for private passenger vehicles and light/medium trucks (representing ~80% of transport emissions) but are more marginal for heavy trucks where green fuels such as hydrogen may be more appropriate. The Ministry for the Environment forecasts that in 2030 electrification of vehicles will have a negative marginal abatement cost, saving costs for consumers and the economy while reducing emissions (see Exhibit 5).

EVs are already near-economic from a whole-of-life perspective. The CCC predicts that the whole-of-life cost of EV ownership will reach parity with internal combustion engines (ICE) in 2026 and will be 20% lower by 2030. By 2035, their modelling suggests a household with an EV would save more than $1,000 in energy costs per year relative to a household with an ICE vehicle (see Exhibit 6).[11]

Exhibit 6: Household energy cost savings in 2035 for a household with one electric vehicle



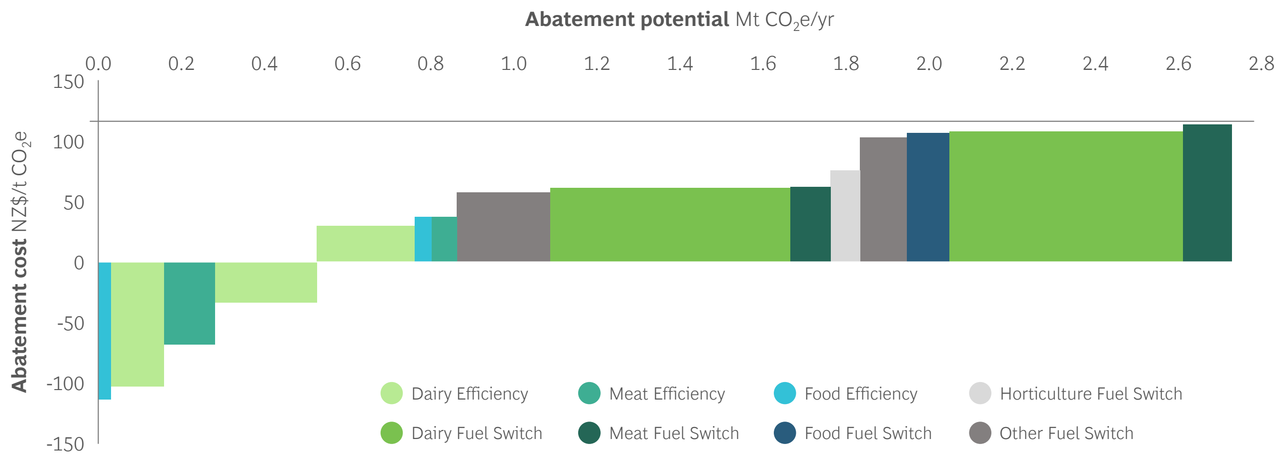
Source: Transpower

11 Climate Change Commission, *Ināia Tonu Nei*, 2021

Heating electrification

After transport, the heat used in industrial processes (process heat) and in space and water heating for buildings is the lowest cost source of emissions abatement available. Process heat, which represents 9% of New Zealand's emissions, includes heat used in activities to cook food (e.g., a bakery oven), activate chemical processes (e.g., in steel smelting), or dry products (e.g., drying milk to form milk powder).

Exhibit 7: **2030 marginal abatement cost curve for process heat**

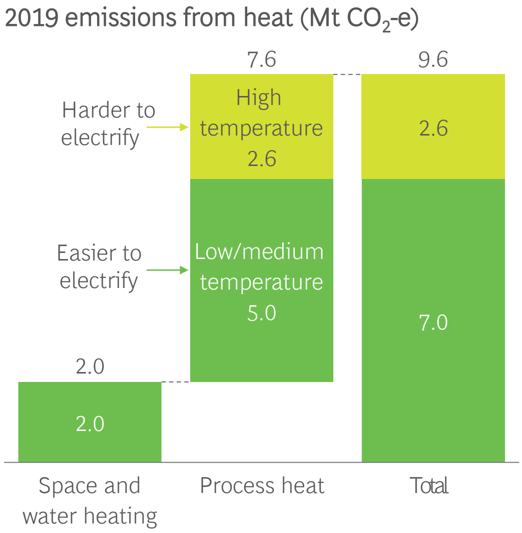


Note: While low/medium process heat contributed 5 Mt of annual emissions in 2019 this analysis only considers part of food processing heat use

Source: Transpower based on Ministry for the Environment 2020 analysis

Both electricity and biomass will reduce emissions in process heat. Low- and medium-temperature heat (below 300°C), including space and water heating, accounts for 73% of New Zealand's heat emissions (7.0 Mt CO_2-e) and is best displaced by electric heat pumps. For medium-temperature processes (100–300°C) like drying milk to make milk powder, biomass is also an effective decarbonisation solution (see Exhibit 7). For higher heat activities (over 300°C), which contribute 2.6 Mt CO_2-e to emissions today, hydrogen may be a more effective way to decarbonise (although in the future, electrification may potentially become more economic). Overall, approximately 9.6 Mt CO_2-e can be abated through electrification, biomass, and/or hydrogen (see Exhibit 8). This represents a large opportunity to reduce New Zealand's emissions.

Exhibit 8: **7 Mt CO_2-e of emissions from space and water heating and low/medium-temperature heat can be abated through electrification**

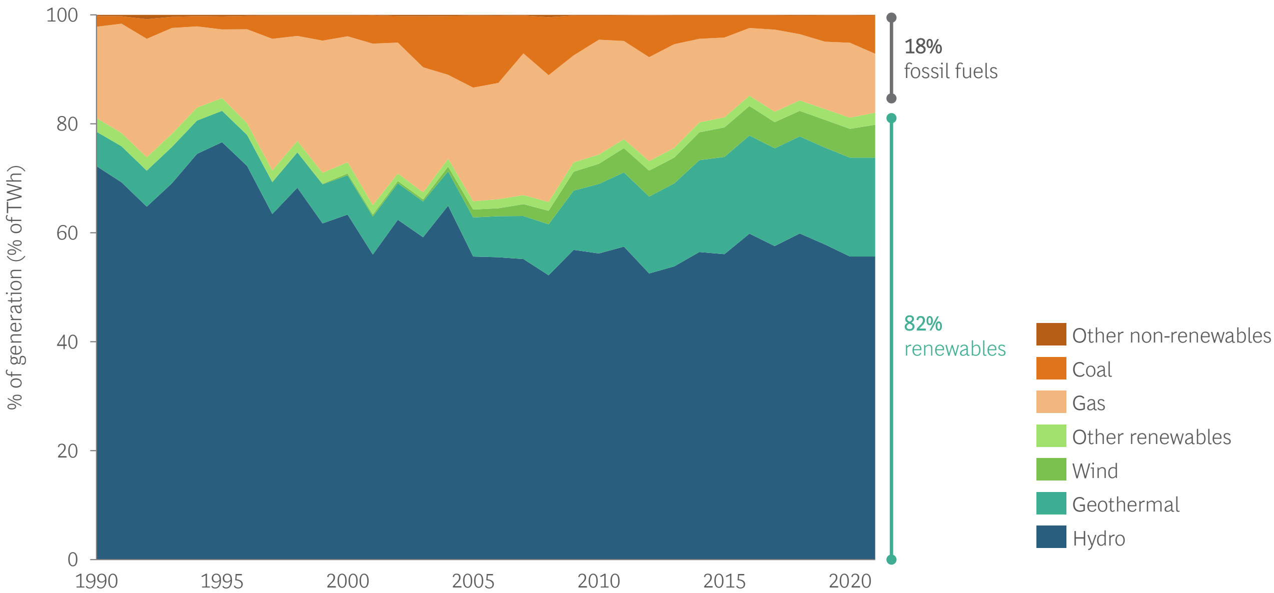


Source: Climate Change Commission

Reducing emissions from electricity generation and electrification

New Zealand has abundant renewable energy resources. For the past decade, more than 80% of electricity generation has come from renewable sources (see Exhibit 9).[12] Hydro provided 58% and geothermal provided 18% of generation in 2019, with the remainder of the renewable electricity produced by wind and solar.[13] The country also has lots of sunshine (average of 1,670-2,100 hours a year), and windy regions (Wellington records 178 days a year at or above gale force).[14,15] New Zealand has developed high-performing wind farms since the 1990s, with capacity factors averaging 40% – well above the global average.[16,17]

Exhibit 9: 82% of New Zealand's electricity generation is renewable today



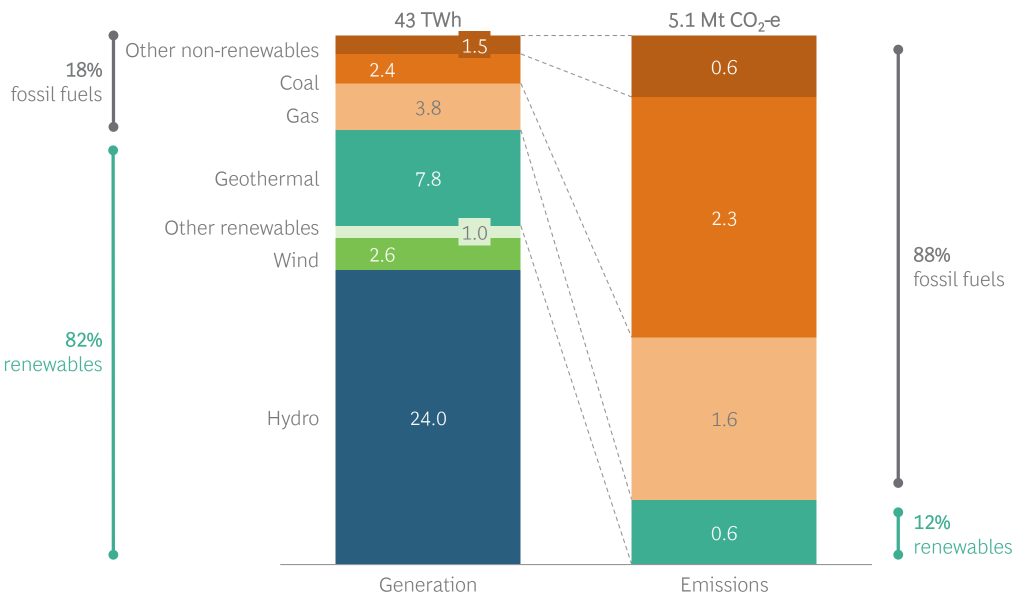
Note: 'Other renewables' includes solar (including estimates of distributed solar PV generation), biogas and wood; 'Other non-renewables' include oil and waste heat

Source: MBIE , BCG analysis

12 Climate Change Commission, Data and Modelling, 2021
13 Ministry of Business, Innovation & Employment, Electricity statistics, 2021
14 National Institute of Water and Atmospheric Research, Mean monthly sunshine (hours), 2022
15 Metservice, Why is Wellington so windy?, 2017
16 Wind Energy, Wind Generation in New Zealand, 2019
17 Luvside, Capacity Factor of Wind Turbine, 2020

However, fossil-fuel-fired power stations still play a significant role in maintaining grid stability – filling gaps when hydro inflows are low and when renewable supply falls short due to the intermittency of wind and solar. As such, electricity generation continues to contribute 6% or 5.1 Mt CO_2-e of New Zealand's gross emissions, and 10% of emissions covered under New Zealand's 2050 net zero carbon target (see Exhibit 10)[18]. Increasing renewables and other lower-emissions generation in New Zealand's electricity mix will make a direct contribution towards meeting national emissions budgets, as well as increasing the decarbonisation impact of electrification.

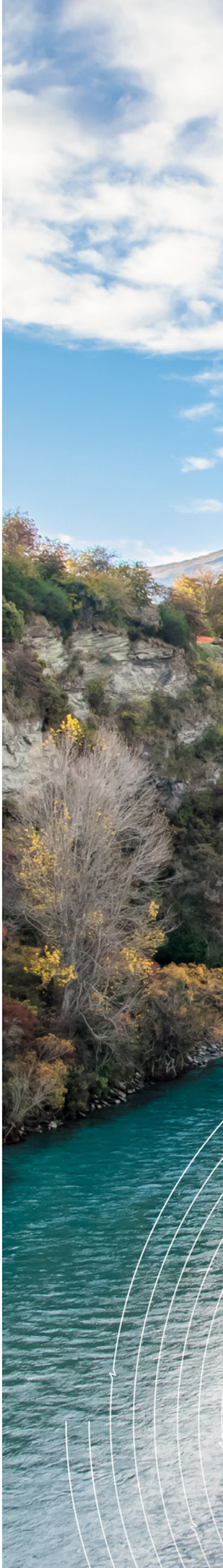
Exhibit 10: **88% of electricity generation emissions today are from fossil fuels**



Source: Climate Change Commission, MBIE, BCG analysis

New Zealand's electricity sector is well placed to transition to more renewable penetration while securely and equitably ramping up electrification. However, to make the most meaningful contribution to New Zealand's net zero ambitions, the electricity sector will have to undergo a significant transformation throughout the 2020s and beyond. The following section examines the state of the sector and some of the challenges it will face throughout the energy transition.

18 Climate Change Commission, Ināia Tonu Nei, 2021



5 New Zealand's evolving energy sector

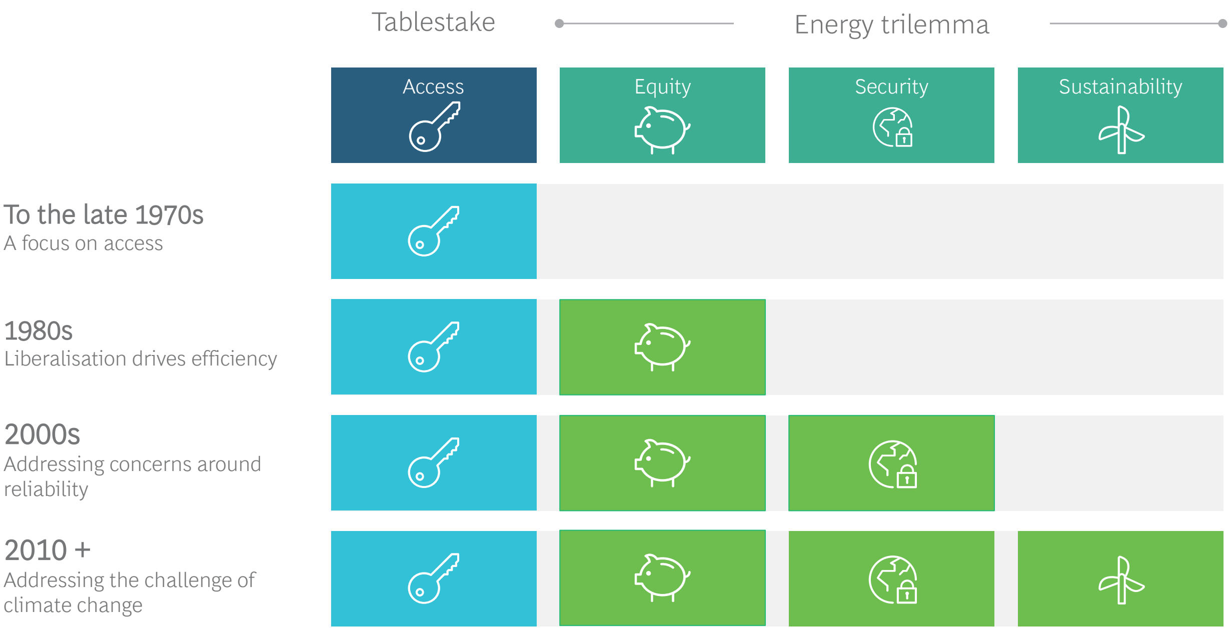
New Zealand's energy sector will need to undergo significant transformation as we focus on decarbonisation. In this section, we:

- Provide an overview of how New Zealand's electricity sector has been shaped by evolving priorities over time, including the current focus on decarbonisation.
- Explore New Zealand's performance on energy equity, security, and environmental sustainability, and how decarbonisation can risk equity and security outcomes if not well managed.
- Assess how decarbonisation is driving 4 trends that will fundamentally change the way the future energy system operates and leave the energy system facing 4 challenges that it will need overcome to decarbonise while maintaining energy equity and security.

5.1 Evolving priorities have shaped New Zealand's electricity sector; decarbonisation is now front and centre

New Zealand's regional electricity networks were first connected to form one national grid in the mid-20th century. Since then, the priorities of the nation's electricity sector have evolved (see Exhibit 11). A full description of the developments that shaped the electricity market as it is structured today can be found in the supporting Appendix 1: Context of New Zealand's Electricity Sector.

Exhibit 11: **The multiple priorities of New Zealand's electricity sector, with different focuses emerging over different timelines**



To the late 1970s: Expanding electricity access

Until the end of the 1970s, improvements in the electricity sector focused on expanding access to electricity across the country. Substantial public sector investments were made to build generation (particularly hydro and thermal) and connect geographically dispersed demand into the grid, often at a high cost.[19,20]

1980s and 1990s: Driving efficiencies through liberalisation

By the early 1980s, 99% of New Zealand's population relied on around-the-clock access to electricity.[21] At this time, the entire electricity value chain was owned and operated by the New Zealand Government. The formation of the Electricity Corporation of New Zealand (ECNZ) in 1987 introduced liberalised market forces. Corporatisation, deregulation, and partial privatisation of electricity assets was pursued to achieve greater efficiency across the system. The New Zealand Wholesale Electricity Market (NZEM) opened in 1996, ensuring that prices could signal an efficient mix of generation resources for dispatch (short-term market outcomes) and investment (long-term market outcomes).

19 Engineering New Zealand, New Zealand Electricity sector, 2022

20 Te Ara, Energy supply and use, 2010

21 Electricity Engineers' Association, Over 125 Years of Electricity Supply, 2022

2000s and 2010s: Improving electricity supply reliability and productivity

Regulation of new transmission investment helped to avoid overspending on grid expansions. However, a series of high-profile grid failures in the 1990s and the 2000s highlighted the risks of not sufficiently investing in network redundancy. There was a multi-week blackout in Auckland's CBD in 1998 and a 7-hour outage in the 2006 Auckland Blackout.[22, 23] In 2009, Auckland and Northland systems were brought down when a forklift knocked out a circuit.

The late 2000s and 2010s saw major grid developments in response to these blackouts. The developments focused on increasing network capacity, replacing, and upgrading deteriorating infrastructure assets, and enhancing the resilience of the grid. The upgrades increased reliability in the electricity sector in New Zealand and ensured that electricity demand was met.

The introduction of performance-based regulation of transmission and distribution networks in the 2010s also improved reliability while providing sufficient incentive for improved expenditure productivity.

2020s: A shift to a strong focus on decarbonisation

Decarbonisation is now a priority on top of access, equity, and security. The challenge for the sector over the coming decades will be ensuring affordable, reliable electricity supply while enabling the rapid decarbonisation of the energy sector.

The 2020s will be a critical decade for New Zealand's electricity sector to support the energy system's decarbonisation. While there was some focus on decarbonisation in the early 2010s, it increased significantly from the late 2010s with the signing of the Net Zero Carbon Act, the announcement of a more aspirational 2030 emissions target, the release of the CCC's *Ināia Tonu Nei:* A Low Emissions Future report, the release of the first emissions budgets and Emissions Reduction Plan, and implementation of a suite of policy reforms including a strengthened Emissions Trading Scheme (ETS).

22 Lindy Newlove, Eric Stern and Lina Svedin, Auckland Unplugged: Coping with Critical Infrastructure Failure, 2003

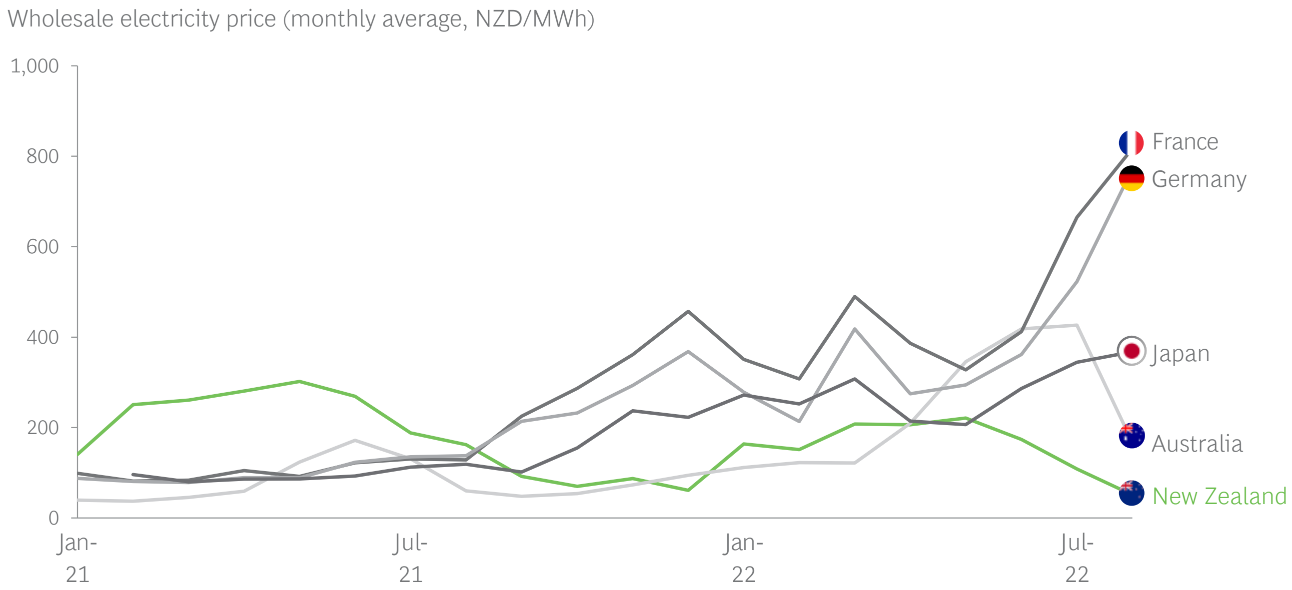
23 Claire Jordan, Henning Rasmussen, and Ratneesh Suri, Expectations for loss of supply in the New Zealand power system, 2006

5.2 New Zealand's energy system has performed well across the energy trilemma

New Zealand's abundant renewable resources have allowed for the bulk of low-emissions energy generation. The national grid accommodates the 3rd highest penetration of renewables in the OECD, making New Zealand a "success story for the development of renewable energy."[24, 25] The decarbonisation of supply has been pursued while upholding the electricity market's other priorities: access, efficiency, affordability (equity), and productivity and reliability (security) of supply.

New Zealand's electricity sector is highly energy independent; 100% of New Zealand's electricity is produced domestically, with 95% of the primary resources used to produce electricity sourced domestically. All renewable energy and gas is sourced domestically (only coal is imported). This means New Zealand's electricity sector is largely shielded from global energy crises, which have led to recent spikes in electricity prices elsewhere (see Exhibit 12).

Exhibit 12: New Zealand electricity sector's resilience to global energy shocks



Source: Electricity Authority, OpenNEM, Refinitiv One, BCG analysis

24 Ministry for Business, Innovation and Employment, Energy in New Zealand, 2019

25 International Energy Agency, New Zealand, 2022

Across the world, energy systems have struggled to realise the degree of grid decarbonisation achieved by New Zealand without risking reliability or causing sizable hikes to electricity bills. Such challenges of the global energy transition have renewed focus on the importance of balancing the 3 aspects of the energy trilemma: equity, security, and sustainability (see At a glance: The energy trilemma). Achieving the trilemma requires the harmonisation of various technical, market, regulatory, environmental, economic, and consumer considerations in the context of rapid decarbonisation. Renewables can help lower emissions, but some of their intermittent supply characteristics require additional reliability measures, which, with current technology, could increase electricity prices.

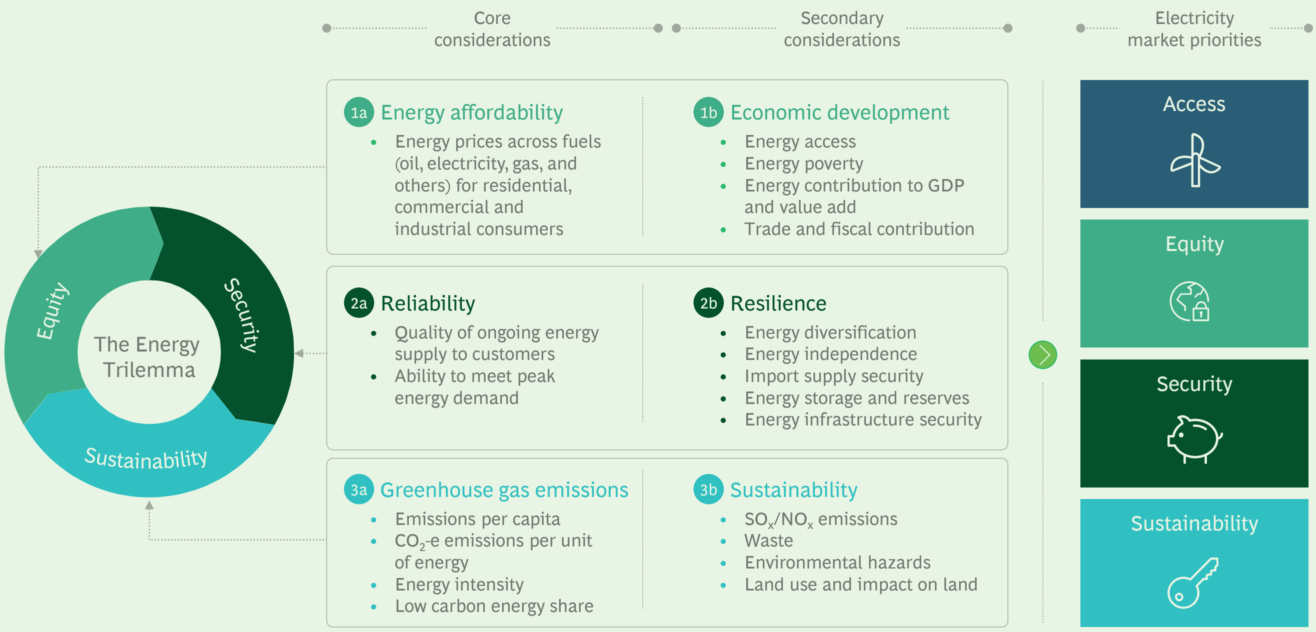
At a glance: The energy trilemma

The energy trilemma, as outlined by the World Energy Council, demonstrates the need for well-functioning energy systems to balance outcomes across 3 dimensions (See Exhibit 13)

- **Energy equity:** Ability to provide universal access to reliable, affordable energy for domestic and commercial use
- **Energy security:** Ability to meet current and future energy demand and the ability to withstand and respond to system shocks
- **Environmental sustainability:** Ability to mitigate and avoid environmental degradation and climate change impacts

Maintaining a balance across these dimensions is a key challenge as we progress to more decentralised, decarbonised, and digital systems with the risk of passive trade-offs between equally critical priorities. Within each dimension of the trilemma, there are core and secondary considerations. While a holistic view of the trilemma has been taken throughout the report, it is the core considerations (energy equity, energy security, and environmental sustainability) that are the focus of the pathways in Section 6.2.

Exhibit 13: **The energy trilemma**



New Zealand's electricity sector has made impressive contributions towards each of the dimensions in the energy trilemma while decarbonising. The country's energy system was ranked 9th in the world and 1st in Asia by the World Energy Council's (WEC) trilemma index in 2021. New Zealand was one of only 9 countries to achieve an A-rating across all 3 elements of the trilemma challenge and, for each factor on its own, was ranked in the top quartile of the 127 countries that were assessed (see Exhibit 14).[26]

Exhibit 14: **New Zealand's Energy Trilemma Index ranking out of 127 countries**

Source: World Energy Council

With respect to the electricity system, New Zealand had the 10th most affordable residential electricity prices in the OECD in 2017 and, from a security and reliability perspective, has been well supported by the electricity sector's market for ancillary services.[27]

26 World Energy Council, World Energy Trilemma Index, 2019

27 New Zealand Government, Electricity Price Review, 2019

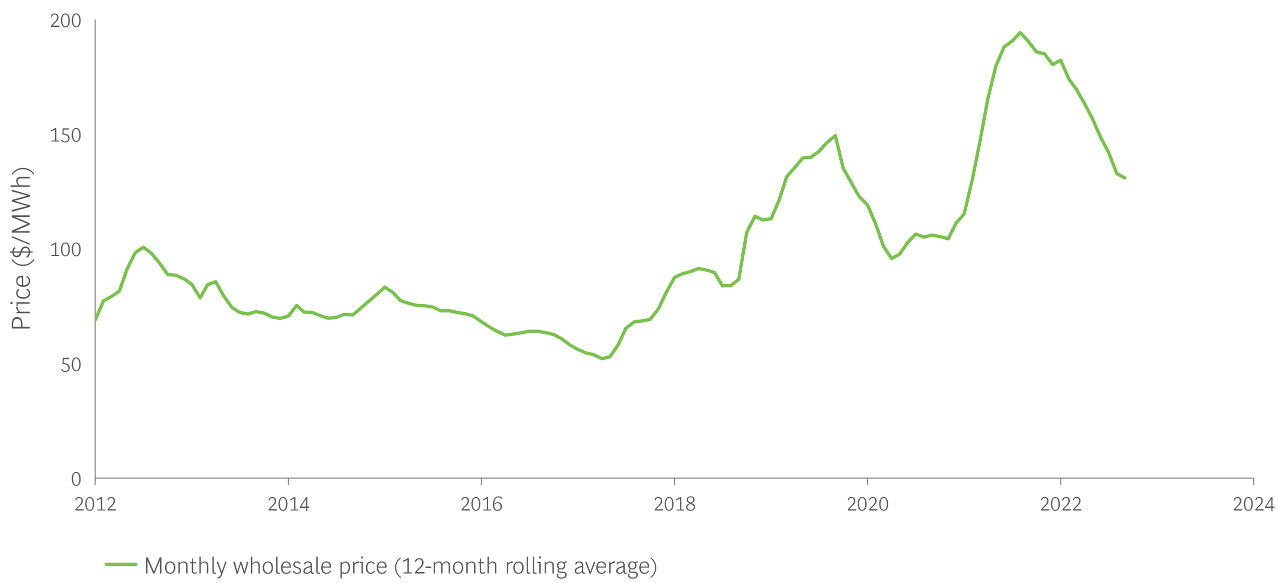
5.3 The global energy transition could risk energy equity and security if not well-managed

When it comes to equity, several factors related to New Zealand's energy transition have placed upwards pressure on wholesale electricity prices in recent years. New Zealand's carbon spot price has more than doubled in the last 2 years, adding to the cost of electricity production from fossil fuels. Meanwhile, coal prices have increased due to New Zealand's imports from Indonesian coal markets. Domestic gas prices have been rising as the Pohokura gas field, which met 40% of New Zealand's gas needs at its peak, has produced less gas than expected. The decline has been significant enough to lead to sustained conditions of tight supply.[28]

The pressure on electricity prices from high thermal fuel costs has been exacerbated by some periods of low hydro inflows and declining lake storage levels. This has increased the cost of hydro generation and at times prompted higher rates of coal-fired electricity as a substitute; Exhibit 15 below outlines the wholesale electricity price over the last decade.[29] Uncertainty over the potential for Tiwai Point's exit to flood the market with additional supply has also led to a systemic under-build of renewable generation projects over the last few years, even as the cost to build new renewables has significantly declined.

In terms of security, due to increasing electricity demand and the rising penetration of intermittent renewables, the electricity system will need to physically balance a more complex and unpredictable residual load profile (i.e., remaining electricity demand net of the component supplied by intermittent renewables).

Exhibit 15: **New Zealand wholesale electricity price over the last 10 years**



Source: Electricity Authority, BCG analysis

28 Gas Industry Co., Gas supply and demand projections – 2022 update, 2022

29 Electricity Authority, What's Behind Current Forward Prices, 2022

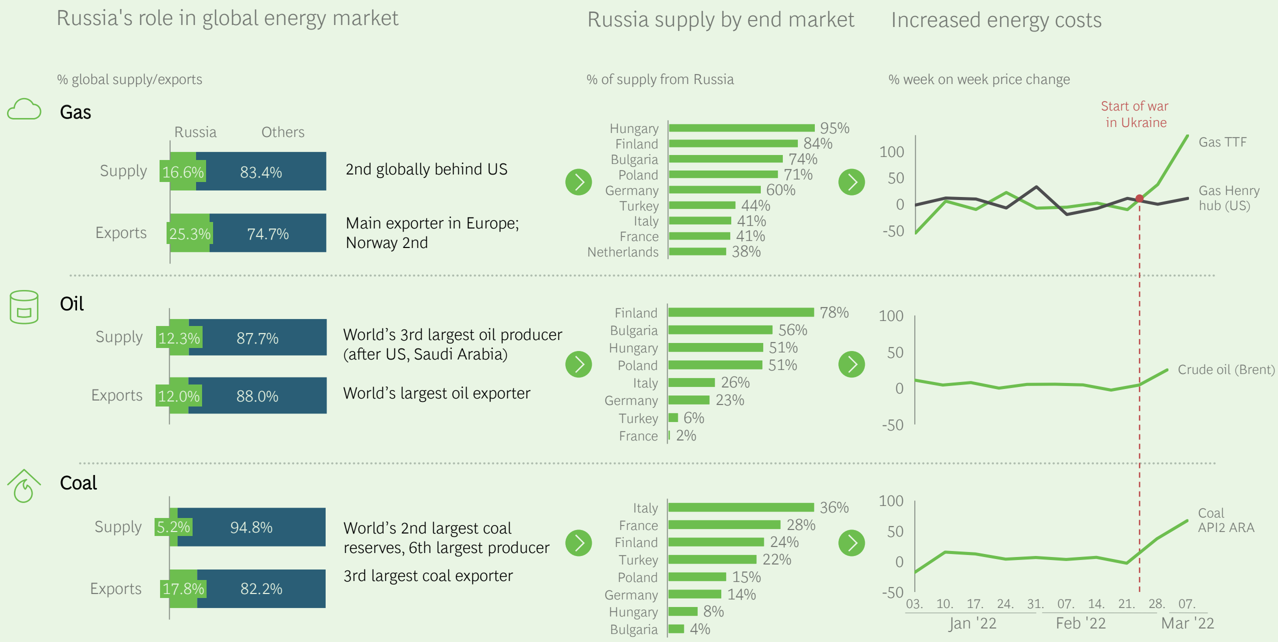
At a glance: Electricity sector disturbances are not unique to New Zealand, but point to emerging risks within the global energy transition

Trends suggest the energy transition is unlikely to always be smooth in any country, highlighting the importance of it being well-managed. As countries shift from fossil fuels to low-carbon sources of electricity, many have been challenged by issues relating to energy security, supply chain pressures, and increased price volatility.

Impact of war in Ukraine

Russia's invasion of Ukraine has thrown energy markets around the world into turmoil, highlighting the geopolitical risks associated with global energy security. Sanctions on Russia – a major exporter of natural gas, oil, and coal – have constrained upstream energy supply chains, impacting the availability and cost of energy for consumers and industries such as steel, chemicals, and transportation. The price hikes that have evolved from these supply and liquidity pressures have had second-order effects, eroding margins in energy-intensive industries, and contributing to inflationary pressures (see Exhibit 16).

Exhibit 16: Risks to energy security from Ukraine-Russia event



Source: International Energy Agency, BP Statistical Review; Eurostat, IHS Markit, S&P Capital IQ, BCG analysis

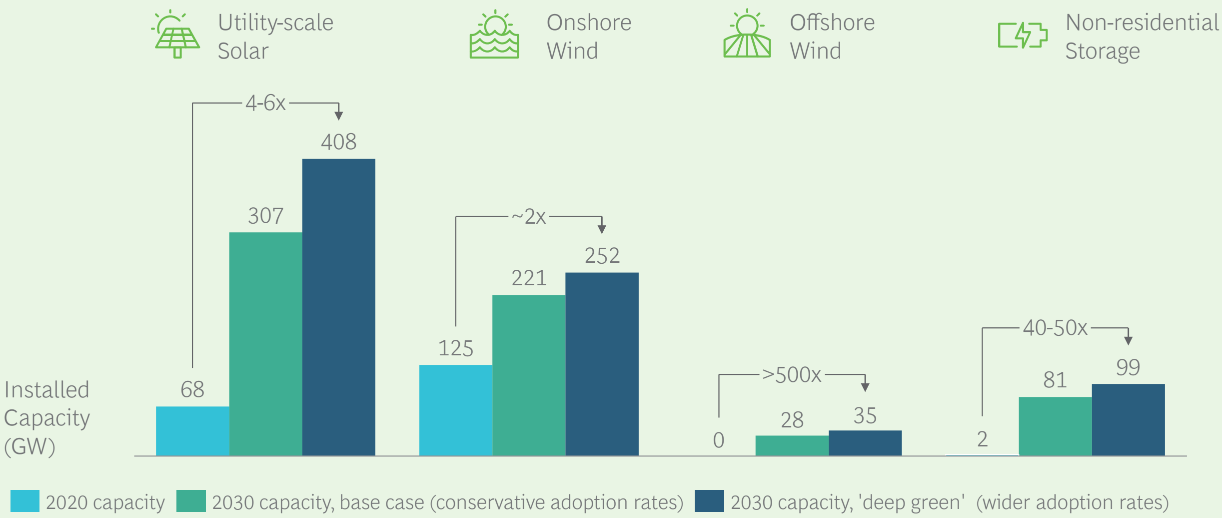
While the current drivers of financial and geopolitical risk could be transient, global energy markets still retain their exposure to fossil fuels. To achieve energy independence, electricity systems around the world must both diversify and decarbonise their sources of energy supply.

The EU has already launched plans through RepowerEU to reduce its dependence on Russian gas imports by two-thirds before the end of 2023. The target forms part of a broader ambition to reduce long-term gas consumption by both diversifying the EU's exposure to key energy security concerns, as well as making a structural shift towards a less emissions-intensive energy mix that will be more resilient to global energy market shocks over the longer term. RepowerEU is targeting ~1 TW of combined new wind and solar capacity by 2030, 2.5 times the existing wind and solar base of 400 GW.

Supply chain pressures

The global energy transition has led to an international surge in demand for renewables and storage capacity across the world. The recently legislated Inflation Reduction Act (IRA) in the United States is anticipated to accelerate the transition away from fossil fuels by providing material incentives for low-carbon electricity generation with almost USD $370 billion in climate and energy funding committed over the next decade (see Exhibit 17). Other substantial pieces of government policy, as well as ambitious private sector commitments, are also accelerating growth in other global markets for renewables and storage technology.

Exhibit 17: **Step-change increase in renewable energy for US from IRA**



Source: BCG analysis

The IRA will accelerate demand for renewable generation equipment in conjunction with increased European demand resulting from the conflict in Ukraine. Outside of the United States and Europe, international action on climate change is also increasing. Globally, this additional activity may see increases in total renewable capacity greater than the average 305 GW per year previously forecast by the IEA to 2026.[30]

30 IEA, Renewables 2021 – Analysis and forecast to 2026, 2021

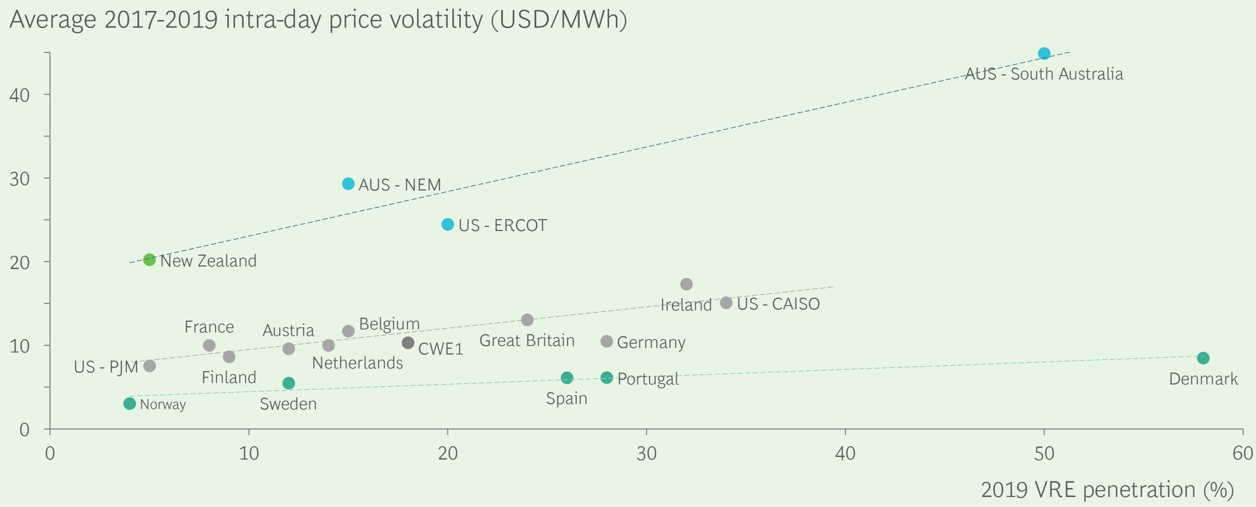
The step-change in international demand is placing pressure on green energy supply chains across the world. Bottlenecks are emerging in low-carbon infrastructure development, and shortages of critical energy resources are driving technology costs higher. To meet the pace of decarbonisation ambitions and avoid unnecessary costs, governments and industries, including in New Zealand, will need to be proactive in establishing their green supply networks, which require forward-thinking to set up in a timely manner.

Price volatility

Higher penetrations of intermittent renewable generation are also driving higher levels of price volatility in electricity markets around the world. The variable generation characteristics of some renewables make demand and supply more challenging to balance, leading to more extreme pricing outcomes. For example, between 2011 and 2019, penetrations of wind and solar increased from around 24% to over half of generation in South Australia. Over the same period, wholesale price volatility has increased by ~180% (from an average typical range of $28 AUD/MWh to $78 AUD/MWh).

Greater volatility in electricity prices is giving rise to new economic challenges for markets across the world. Higher intra-day variability and more seasonal supply-demand imbalances are creating problems around resource adequacy, as well as frequency and voltage stability. The viability of many conventional, slow-start power plants is also being challenged. Most electricity systems, including New Zealand's, will require new fast-start dispatchable capacity and increased flexibility on the demand-side to continue operating securely and reliably. Exhibit 18 below highlights the strong correlation between penetration of Variable Renewable Electricity (VRE) and price volatility.

Exhibit 18: **Correlation between higher Variable Renewable Electricity penetrations and increasing price volatility**



1. Based on load-weighted average intra-day price volatility for Central-West Europe, incl. Belgium, France, Germany, Netherlands. Note: Assuming constant 2019 exchange rates of 1.12 USD/EUR, 0.7 USD/AUD, 0.66 USD/NZD, and 1.28 USD/GBP; Using hourly day-ahead prices for Europe, using hourly average spot prices for Australia, using hourly average wholesale prices for New-Zealand, using hourly day-ahead LMP prices for the different hubs within CAISO, ERCOT, and PJM; Averaging the std dev for the different zones/hubs within a region (for those regions consisting of multiple zones/hubs); Source: ABB Velocity; AEMO; Australian Government, Department of Industry, Science, Energy and Resources; EIKON; EMI; ENTSO-E; EUROSTAT; EXAA; IRENA; Nordpool; OMIE; S&P Global; BCG analysis

5.4 Decarbonisation is changing the context: 4 trends that will change New Zealand's energy system

There are a confluence of factors influencing Aotearoa New Zealand's energy transition. The drive to decarbonise the energy system will lead to **4 trends** that result in fundamental changes to the way the future energy system will operate (see Exhibit 19):

- Higher rates of electrification
- More intermittent renewable generation
- Less thermal generation
- A more distributed electricity system

Exhibit 19: 4 key trends changing the future energy system

Drivers of decarbonisation	Future trends	Energy system changes
• Policies supportive of electrification • Decreasing electric transport and heat costs • Higher carbon prices	1 Higher rates of electrification	• Increased energy demand • Greater peaks in demand profile • Increased need for resilience
• Higher carbon prices • Declining solar and wind generation costs	2 More intermittent renewable generation	• More variable and less predictable supply
• Higher carbon prices • Declining solar and wind generation costs • Declining cost of storage	3 Less thermal generation	• New types of flexible resources to meet peak capacity and dry year energy needs
• Declining costs of Distributed Energy Resources (DER) • Increasing digitisation and smart technologies	4 More distributed electricity system	• Increased need for system smarts to integrate DER

1. Higher rates of electrification

Drivers of higher rates of electrification

Electrification is being driven by a combination of policies that support electrification, declining electrification technology costs, and rising carbon prices.

Policies supportive of electrification: Several policies are driving electrification. In the transport sector, the New Zealand Government is targeting a 41% decrease in 2019 transport emissions by 2035.[31] This will be facilitated through the electrification of at least 30% of New Zealand's light vehicle fleet, building on progress made so far under the 2021 Clean Car Discount.[32] Since the introduction of the Clean Car Discount, average monthly registrations of EVs have increased by nearly 5 times (see Exhibit 20). On the supply-side, the Clean Car Standard will see EVs increasingly favoured by applying tighter emissions standards to imported vehicles over time.[33]

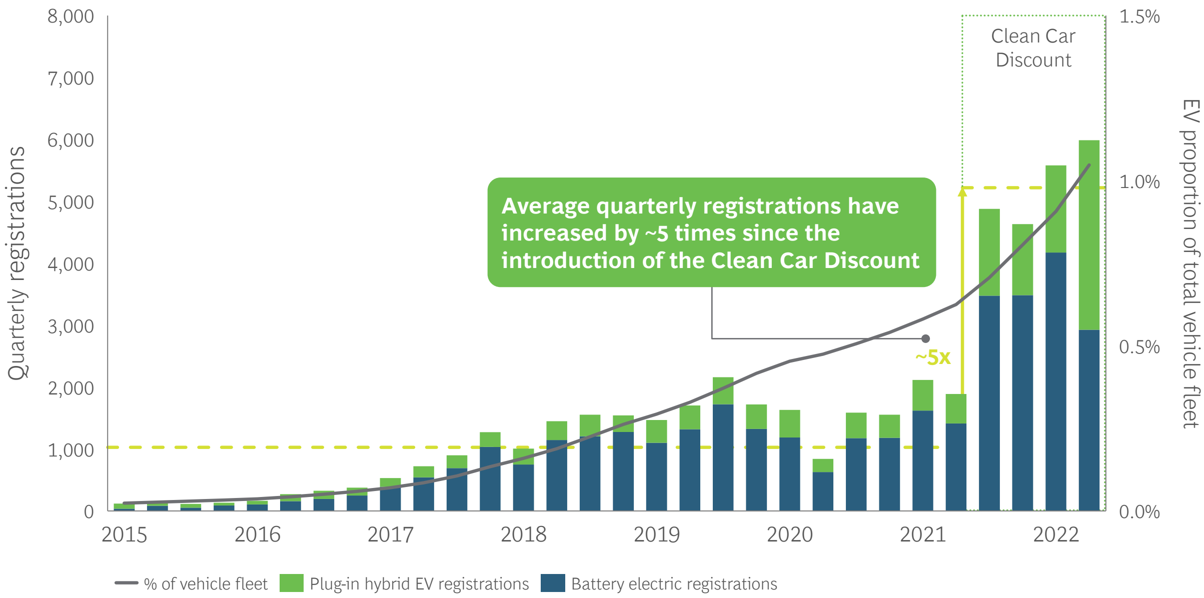
Industrial process heat will be another key driver of electrification. Improving economics continue to enhance the appeal of commercial fuel-switching; electrifying uses of low-temperature heat can already save 40–70% of

31 Ministry of Transport, Climate change – emissions work programme, 2020

32 Ministry of Transport, Clean Cars, 2022

33 Ministry of Transport, Clean Cars, 2022

Exhibit 20: 5 times increase in New Zealand's electric vehicle registrations since the introduction of the Clean Car Discount



Source: Ministry of Transport

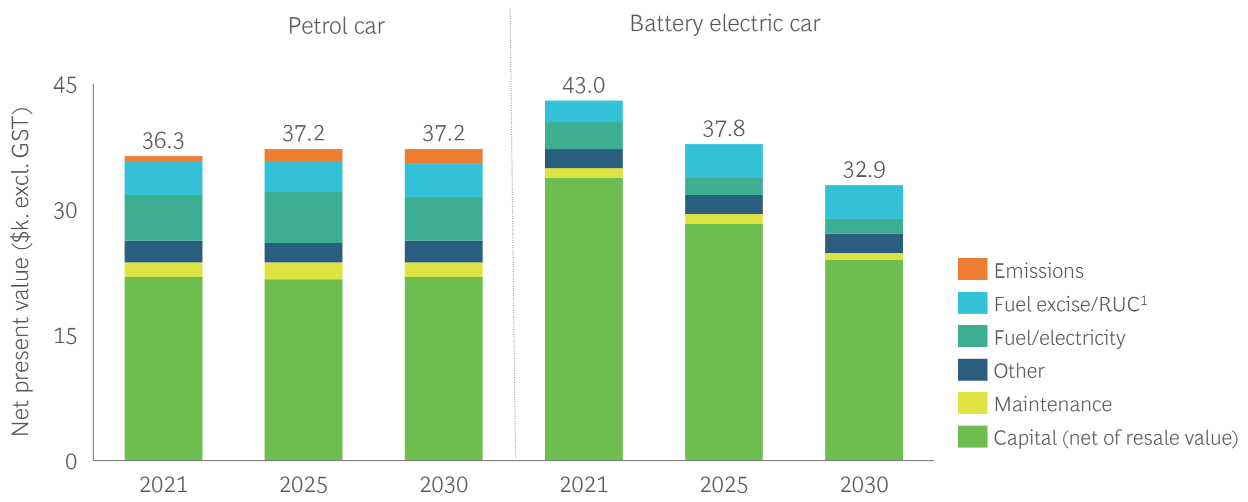
operating energy costs.[34] However, upfront capital costs remain a deterrent to electrification. As such, the recent $650 million expansion of the Government Investment in Decarbonising Industry (GIDI) program – almost 10 times the original fund's size – will play an important role in helping process heat users overcome electrification capital hurdles. After the first 3 rounds of the GIDI fund, 28 electrification projects have been awarded a total of $33 million in co-funding, equating to close to an expected 3 million tonnes of lifetime CO_2-e emissions reductions.[35]

The New Zealand Government has also banned the installation of new low- and medium-temperature coal-fired boilers, with existing facilities required to be phased out by 2037.[36]

Decreasing electrification technology costs: Realising parity between the total ownership and upfront costs of EV and internal combustion engine (ICE) vehicles will be important to increasing the use of low-emissions vehicles. EVs are becoming cheaper to maintain and fuel; the whole-of-life cost for a new EV is already close to that of ICE vehicles and battery technology innovations are forecast to continue to bring EV prices down.[37] The effective purchase cost of EVs for consumers is further reduced by the Clean Car Discount, which provides a discount of up to $8,625 for new EVs and up to $3,450 for used vehicles (GST inclusive, see Exhibit 21).[38]

34 Transpower, Electrification Roadmap, 2021
35 Energy Efficiency & Conservation Authority, Approved GIDI projects, 2021
36 New Zealand Government, Government delivers next phase of climate action, 2021
37 Climate Change Commission, Ināia tonu nei: A low emissions future for Aotearoa, 2021
38 Waka Kotahi NZ Transport Agency, Clean Car Discount overview, 2022

Exhibit 21: **Total cost of ownership for petrol and electric cars to 2030**

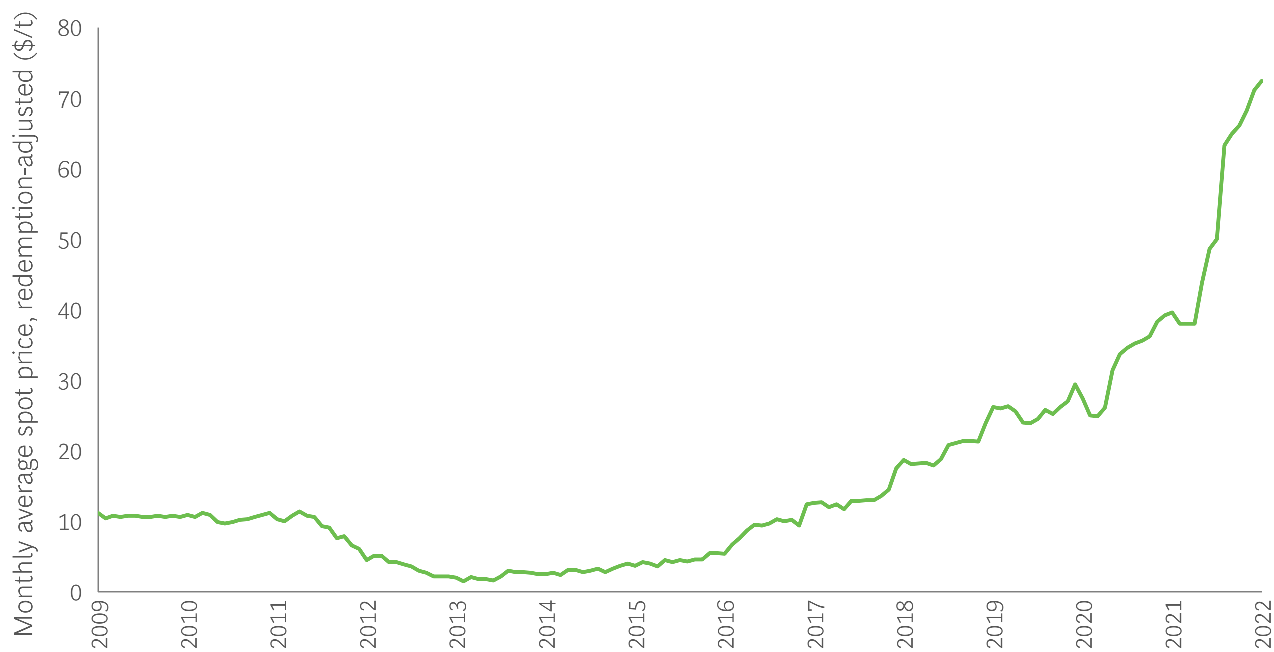


1. Road user charges

Source: Climate Change Commission

Higher carbon prices: Under New Zealand's ETS, the price of carbon has increased from $10–$20 per New Zealand Unit (NZU) 5 years ago, to over $80 per NZU today (see Exhibit 22). The carbon price is expected to continue to increase over the long term after recent major reforms of the ETS, incentivising electrification and more renewable generation, and disincentivising thermal generation and fossil fuel use in transport and heat.

Exhibit 22: **New Zealand carbon spot price since 2009**



Source: Carbon News New Zealand, BCG analysis

Energy system changes due to higher rates of electrification

Electrification will increase energy demand, peak demand, and the need for system resilience.

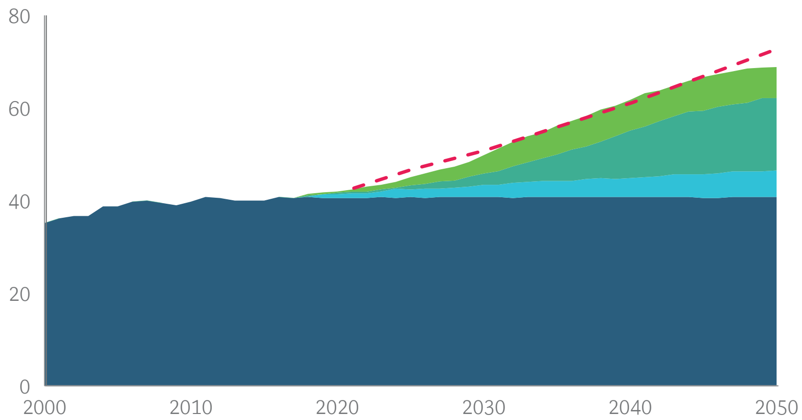
Increased energy demand: With accelerating rates of electrification, modelling from Transpower in 2020 anticipated electricity demand will increase by 20% by 2030 and 68% by 2050. Concept Consulting's modelling for this report produces results similar to the Transpower forecasts, as shown in Exhibit 23 below.

This demand will require much more renewable generation, more transmission networks to enable this generation (and to some extent distribution) and more dry year cover to meet an increasing energy gap.

Greater peaks in demand profile: With accelerating rates of electrification, peak demand will also increase. Our modelling shows that peak demand is anticipated to increase by 28% by 2030 and 93% by 2050, prior to contributions from EV smart charging and demand response.

Exhibit 23: **71% increase in New Zealand's gross electricity demand by 2050**

(TWh, Accelerated Electrification)



Energy demand growth contribution 2019-2050

	Transpower Sub-totals shown on graph	Concept Total shown with pink dotted line
Total	+68%	+71%
Process, space and water heat	+16%	+18%
Vehicle electrification	+38%	+37%
Base growth	+14%	+16%
Historical baseline	Flat	Flat

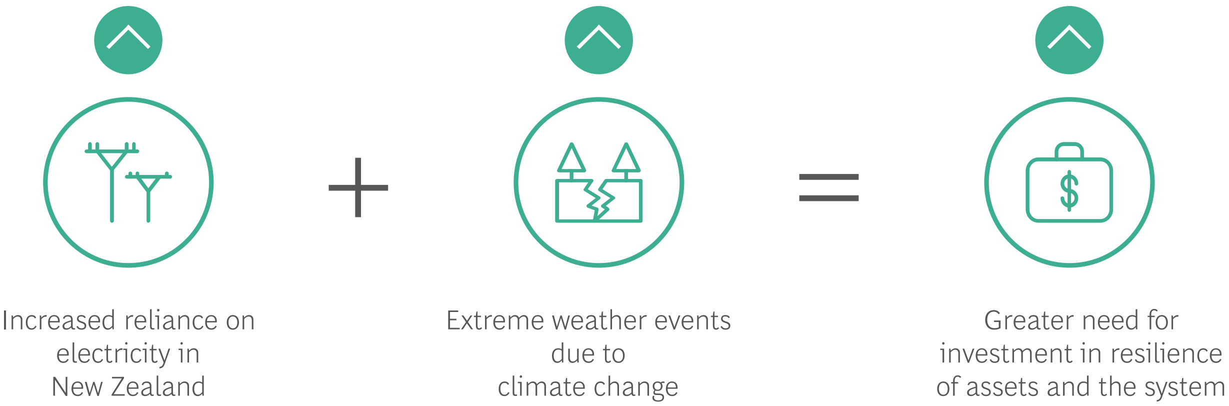
Source: Transpower Whakamama i Te Mauri Hiko (March 2020) - Accelerated Electrification Path; Concept Consulting, BCG analysis

This will require more fast-start flexible supply-side and demand-side resources. It will also require distribution networks (and to some extent transmission) to develop new infrastructure to enable electrification and associated increasing peak demand.

Increased need for resilience: An electrified future will increase New Zealand's dependence on uninterrupted, reliable electricity supply. To drive adoption of electrified technologies, the economy needs confidence that electricity can be delivered where and when it is needed. In the face of climate change, however, meeting this need is challenged by more extreme weather events, which can cause damage to generation equipment, poles and wires, and lead to supply interruptions. Increasing the resilience of important assets (such as the HVDC cable) where there is a concentration of risk will be important in future (see Exhibit 24).

Distributed, flexible, and smart energy resources will play a role in improving the resilience of New Zealand's future electricity supply. Strengthening the physical assets of the system, as well as building out the degree of redundancy they operate with, will also help to reduce the risk of electricity outages, and ensure consumer confidence in the prospects of electrification.

Exhibit 24: **Additional need for resilience investments**



This will require more resilient generation, transmission, and distribution assets and increased energy market reserves to meet peak demand to cover high impact, low probability events.

2. More intermittent renewable generation

Drivers of more intermittent renewable generation

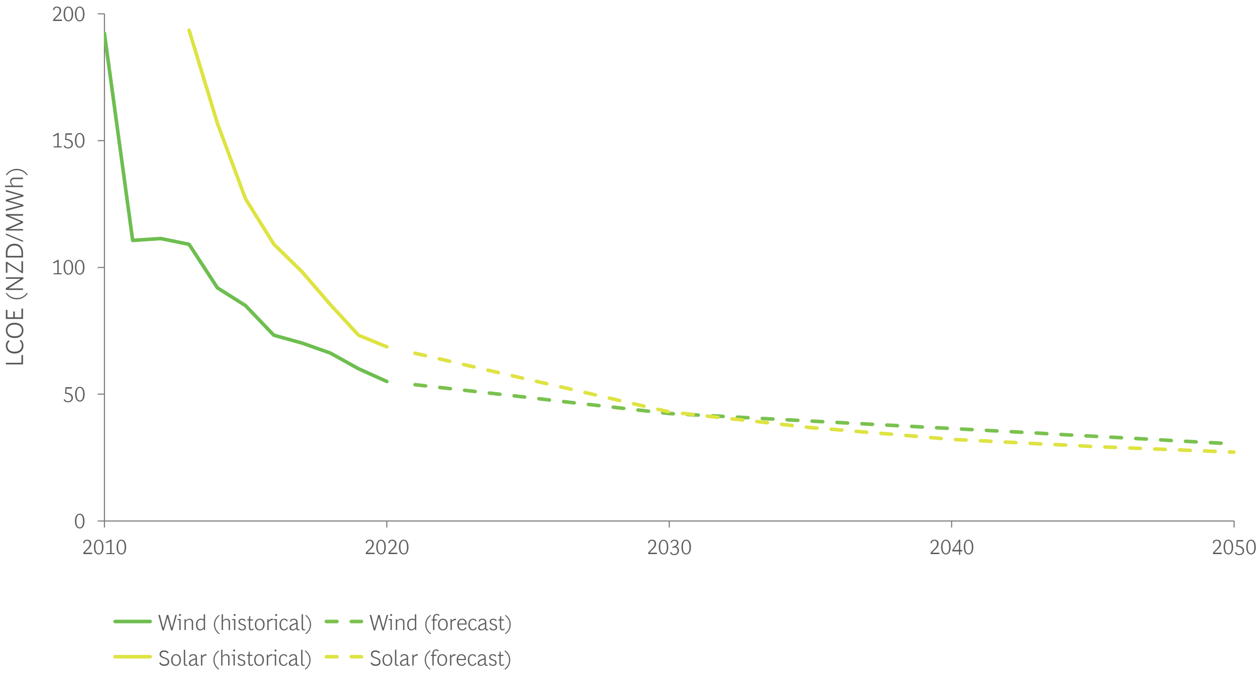
Intermittent generation will be driven by an increasing carbon price (discussed under drivers of **higher rates of electrification**), as well as declining solar and wind generation costs.

Declining solar and wind generation costs: Our modelling forecasts that, by 2030, assuming New Zealand's Tiwai Point smelter remains, ~4,400 MW of new utility-scale solar and wind will be needed to achieve 98% renewable electricity and meet increasing demand. Technology innovation continues to enhance the commercial prospects of intermittent renewables by driving down the levelised cost of energy (LCOE) – between 2013 and 2020, the energy cost of wind and solar have fallen by 50% and 65% respectively and is forecast to continue to decline in future.[39] However, current supply chain pressures and inflation are

39 Transpower, Electrification Roadmap, 2021

increasing the cost of renewable technologies. We expect this phenomenon to be transitory and that, over the long term, declines in the cost of renewables will continue. Exhibit 25 below does not include recent increases in LCOEs due to supply chain pressures but is more demonstrative of the longer-term trend of renewable energy technology costs.

Exhibit 25: **Historical and forecast declines in renewable levelised cost of energy**



Source: Transpower

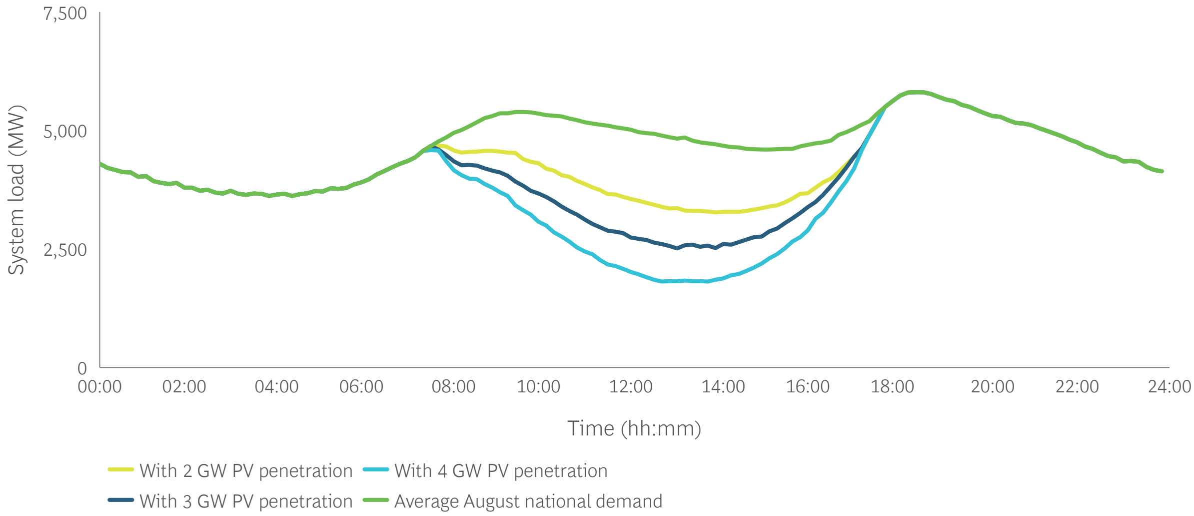
Energy system changes due to more intermittent renewable generation

More intermittent generation will lead to more variable and less predictable electricity supply.

More variable and less predictable supply: In future, an increasing focus will be meeting peak energy demand when wind and solar generation drops due to changes in weather.

Greater penetration of solar will also carve out the residual load curve (known commonly as the *duck curve effect*). Midday generation from solar PV will create a steeper system load profile for the system to meet. This increases the gradient of peaks, which requires flexible resources that can ramp up faster (see Exhibit 26).

Exhibit 26: **Typical daily system load profile under different solar penetrations**



Source: Transpower, BCG analysis

This will require flexible capacity to meet peak demand. In time, the value of slow-start thermals will decline as they become less able to dynamically come in and out of the market quickly to balance intermittent generation in a system of 95%+ renewables. Our modelling predicts that the median time thermal plants will generate per start will decline by 83% from 24 hours today to 4 hours in 2030. The mean time thermal plants will generate per start will decline by 97% from 215 hours today to 6 hours in 2030.

This will also require networks to dynamically balance supply and demand across the system. In future, the grid will become increasingly important for accommodating intermittent generation to dynamically balance out changes in regional supply and demand. For example, if weather patterns lead to declining renewable generation in the North Island, the grid will be able to transfer electricity South to North to balance the system.

In future, this will also create opportunities for new renewable generation projects to pair storage assets to firm their production output.

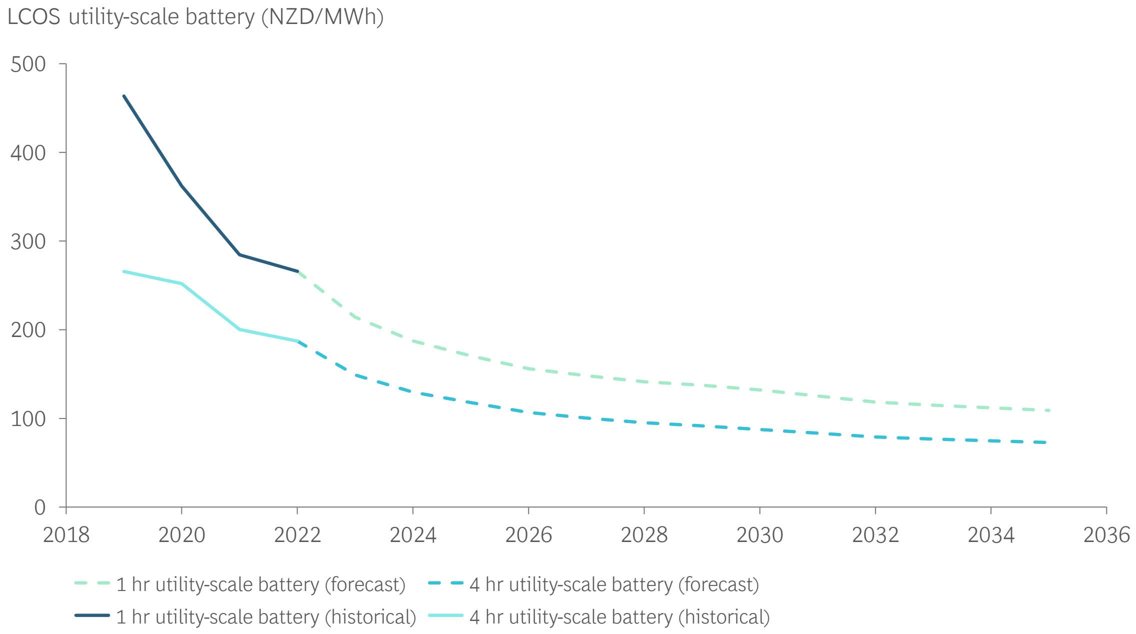
3. Less thermal generation

Drivers of less thermal generation

Less thermal generation will be driven by higher carbon prices (discussed in drivers of **higher rates of electrification**), declining solar and wind generation costs (discussed in drivers of **more intermittent renewable generation**), and declining cost of storage.

Declining cost of storage: Flexible storage has the potential to displace thermal generation for peak capacity and long-duration storage has the potential to displace thermal generation for dry year energy needs.

Exhibit 27: **Historical and forecast declines in levelised cost of storage**



Note: LCOS figures use Australian data as a proxy for New Zealand costs
Source: Bloomberg; BCG analysis

Utility-scale battery costs have declined by over 60% in the past decade, with a further 50% reduction forecast by 2030 (see Exhibit 27).[40]

Energy system changes due to less thermal generation

New types of flexible resources to meet peak capacity and dry year energy needs: In the 2020s, New Zealand's electricity sector will quickly transition from baseload, mid-merit, and flexible resources to a system dominated by intermittent and flexible resources. Assuming Tiwai Point smelter remains, Concept Consulting forecasts that thermal generation will decline by 93% from 6,250 GWh today to 450 GWh (excluding cogeneration) in an average year by 2030. During this time, thermal capacity is forecast to decline from 2.1 GW to 0.7 GW. Capacity utilisation of thermal generation will decline by 77% in relative terms, from 34% to 8%.

With less thermal generation, New Zealand's energy system will need renewable overbuild, demand response, demand-side flexible resources, and storage to meet peak demand and dry year energy needs. From a whole of sector perspective, it will be important to consider peak demand and dry year system needs and potential solutions together. This is because some technologies can provide both peak demand and dry year energy cover while others only provide one of the 2. This whole of system thinking is covered in Section 5.6.

40 National Renewable Energy Laboratory, Cost Projections for Utility-Scale Battery Storage: 2021 Update, 2021

Through the transition, it will be critical that the electricity market can evolve to ensure that the right incentives are in place to ensure peak capacity and dry year resources are developed.

4. More distributed electricity system

Declining costs of distributed energy resources and increasing digitisation and smart technology will drive a more distributed electricity system.

Declining costs of distributed energy resources (DER): As the cost of DER, such as residential and commercial solar and batteries decline, their uptake is forecast to increase significantly. Between 2010 and 2020, the cost of a residential solar PV system declined by 65%, with a further decline of 60% predicted in the 2020s, according to the National Renewable Energy Laboratory (NREL).[41,42] NREL also predicts residential batteries will continue declining in cost, reducing by up to 50% this decade.[43]

While purchased primarily for their transport services, EVs can also act as DER across networks. As costs of EVs decline, Concept Consulting's modelling forecasts there will be 1 million EVs in 2030, 2.4 million EVs in 2040, and 4.3 million EVs in 2050. In time EVs will become the largest source of demand-side flexibility in New Zealand, overtaking hot water ripple systems.

Increasing digitisation and smart technology: New smart technologies like automation, AI, Internet of Things (IoT), real-time communication, and network visibility by household will revolutionise the way electricity systems are operated. As technology improves and the cost of IoT sensors decline, it is likely that millions of DER will be able to interact in real-time with the electricity system.

This provides a significant opportunity to increase consumer participation in markets and more effectively manage complex multi-directional electricity flows that will emerge in future.

Energy system changes due to a more distributed electricity system

Increased need for system smarts to integrate DER: DER – such as such as rooftop solar, battery storage, EVs, hot water systems, smart appliances, smart meters, and home energy management technologies – will play an important role in New Zealand's decarbonisation. With the ability to smooth peak demand and provide an alternative solution to new generation or network infrastructure in certain scenarios, they can deliver significant cost savings, greater security of supply, and increased system resilience.

For example, if most consumers were to plug their EVs in at the end of the day, the grid's evening peak could increase by an additional 20% in 2035 relative to a system with smart load management (where EVs are charged at the optimal time of day).[44]

The future energy system will require smarter coordination of DER to assist with meeting peak demand and increased network smarts to significantly reduce the physical network infrastructure needed.

Peak loads remain a key driver of network and generation investment costs, with one electrical distribution business (EDB) indicating meeting peak demand accounts for nearly half its costs.[45] Every MW of avoided peak demand is estimated to save New Zealand $1.5 million in generation, transmission, and distribution investment costs.[46] As such, increasing peak loads have the potential to undermine electricity equity and inhibit electrification efforts elsewhere in the economy.

41 National Renewable Energy Laboratory, Solar Installed System Cost Analysis, 2021
42 National Renewable Energy Laboratory, Residential PV, 2020
43 National Renewable Energy Laboratory, Residential Battery Storage, 2021
44 Transpower, Whakamana i Te Mauri Hiko, 2020
45 New Zealand Government, Electricity Price Review, 2018
46 Transpower, Whakamana i Te Mauri Hiko, 2020

5.5 Four energy challenges core to the sector's transition

These trends leave the sector facing **4 challenges** to maintain and improve energy equity, security, and sustainability (see Exhibit 28):

- **Renewable generation:** Develop new renewable generation at a sufficient pace.
- **Peak demand:** Ensure sufficient flexible generation and demand capacity to meet increasing peak demand.
- **Dry years:** Ensure sufficient flexible generation and demand energy for dry years.
- **Networks:** Develop sufficient distribution and transmission infrastructure (including smart virtual infrastructure) to enable new electrification, generation, flexible capacity, and flexible energy.

Exhibit 28: Solutions needed to address 4 challenges

Future trends	Energy system changes	System solutions across the 4 challenges			
		1 Renewable generation	2 Peak demand	3 Dry years	4 Network
Higher rates of electrification	Increased energy demand	More renewable generation development needed		More dry year cover needed to meet increasing energy gap	More network infra. needed to enable renewable generation
	Greater peaks in demand profile		More flexible supply-side and demand-side capacity needed		More network infra. needed to enable electrification
	Increased need for resilience		Increased need for reserves to cover high impact, low probability events		More resilient transmission and distribution needed
More intermittent renewable generation	More variable and less predictable supply	Opportunity for renewable generation to be paired with storage to firm output	Flexible capacity increasingly needs to be fast-start to balance changes in system		Grid needs to dynamically balance supply and demand across system
Less thermal generation	New types of resources needed to meet peak capacity and dry year energy		More storage and demand-side flexible resources needed to help meet peaks	Renewable overbuild, demand response, and/or deep storage needed to help meet dry year energy	
More distributed electricity system	Increased need for system smarts to integrate DER		Smarts needed to better coordinate DER to assist with meeting energy peak demand		Network smarts needed to enable significant increase in flexibility to reduce level of physical network infrastructure needed

At a glance: System stability is an important issue for the electricity system

While maintaining system stability (including managing frequency, voltage, and harmonics) will become more difficult in the future, it has not been identified as a key challenge as it is currently being managed effectively.

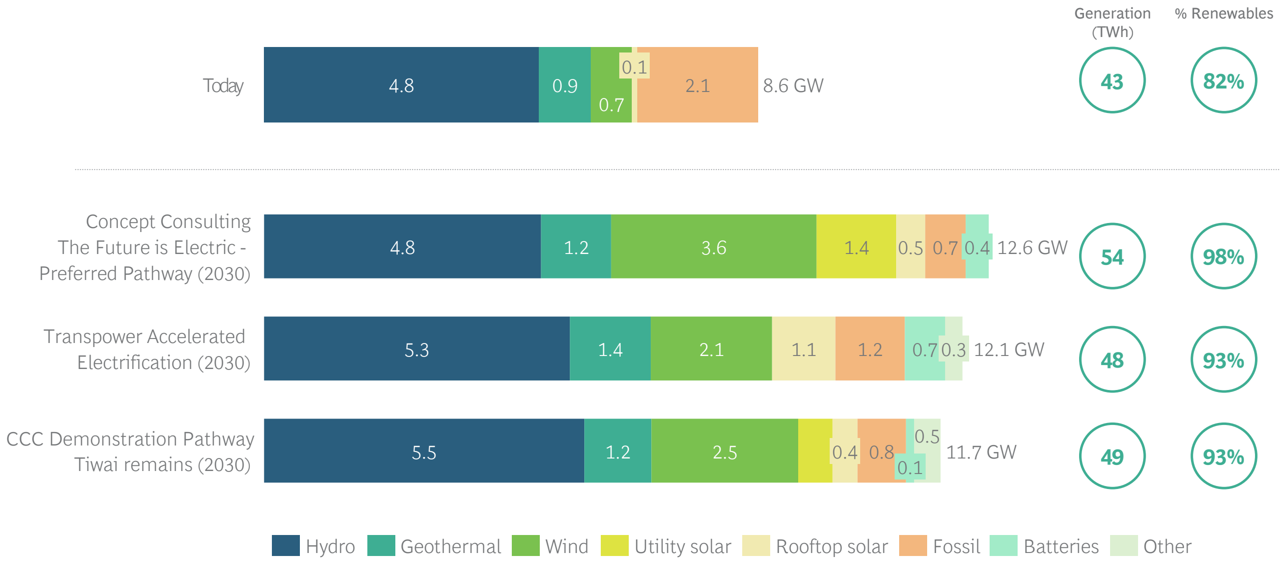
- The New Zealand electricity system is relatively well placed to manage frequency issues given high level of renewable inertia provided by geothermal and hydroelectricity.
- Transpower's Waikato Upper North Island Voltage Management project and other investigations are addressing voltage issues.
- The Future Security and Resilience (FSR) work program that Transpower and the Electricity Authority has underway is sufficient to meet future system stability needs, including for distribution networks as more inverter-based technology is introduced.

Challenge #1: Renewable generation

To facilitate the decarbonisation of New Zealand's energy system, new renewable generation will need to be developed at a sufficient pace to meet electricity demand, displace thermal generation, and replace retiring renewable capacity. The development of new generation could also meet peak and dry year demand, depending on the renewable generation types and other technologies. Exhibit 29 below shows 3 different models of total capacity required in 2030 (being Concept Consulting's model for this *The Future is Electric* report, Transpower's *Accelerated Electrification* report, and the CCC's *Tiwai Stays with Certainty)*.

The 2020s will be a critical decade for the development of new renewable generation. Concept Consulting estimates that 11 GW of utility-scale renewables (that is hydro, geothermal, wind, and utility solar farms) could be enough to enable renewable penetration of ~98% by 2030, up from ~82% today.[47]

Exhibit 29: **Total capacity to meet 2030 system needs**



Note: Capacity factors applied to CCC demonstration pathway generation figures.

Source: Concept Consulting modelling, BCG analysis, Transpower, Climate Change Commission

47 Includes both utility and small-scale renewables

Depending on the volume of generation and penetration of renewables within each of the above models, a different capacity stack could also feasibly meet the system's 2030 needs. For example, Transpower's Accelerated Electrification scenario keeps 1.2 GW of thermal capacity in the system out to 2030. Lower renewables penetration and generation volumes are achieved under this capacity mix, but only 8.8 GW of utility-scale renewables[48] are required to meet demand under this scenario. Under the CCC's Demonstration Pathway, in a scenario where Tiwai Point remains, 9.9 GW of large-scale renewables achieves renewables penetrations of 93%.

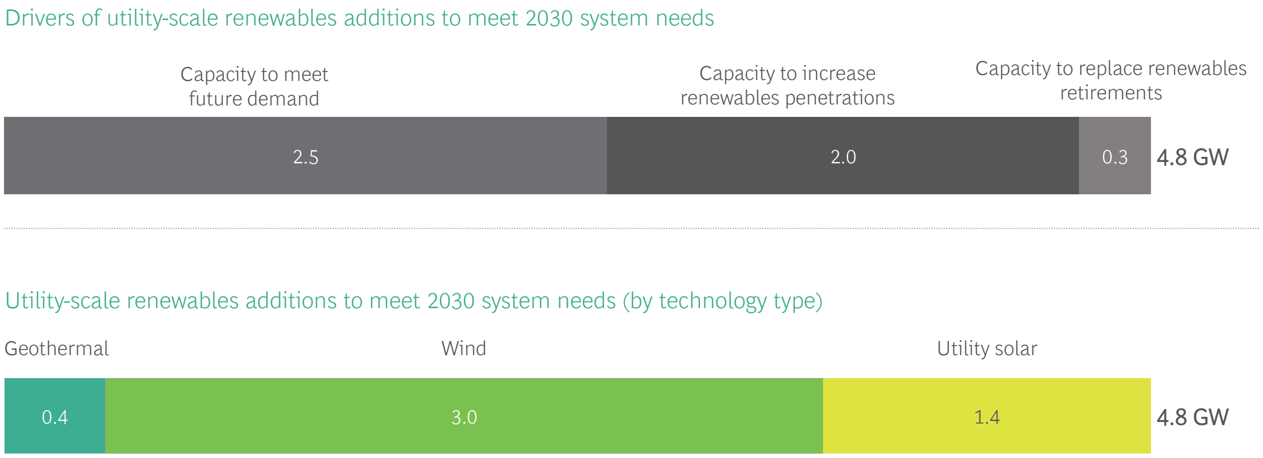
All these potential capacity stacks indicate that the future electricity system will require significant renewables additions, on top of existing levels, by 2030. New renewables projects will be driven by both decarbonisation and growth in demand, and will need to:

- Meet increases in electricity demand caused by electrification and normal growth factors;
- Displace thermal generation with higher penetrations of renewables; and
- Replace the capacity of any renewables being retired from the system.

Concept Consulting models that ~4.8 GW of new utility-scale renewables capacity will need to be plugged into the electricity grid by 2030. Of this, 2.5 GW will be required to meet increases in electricity demand, driven by electrification and baseline growth. 2.0 GW will be needed to increase renewables penetrations and allow the displacement of 1.4 GW worth of thermal-fired capacity.[49] 0.3 GW worth of renewables are also expected to be retired by 2030 and will need to be replaced (see Exhibit 30).[50]

These expansions will need to occur at significant pace and scale to continue to meet grid needs over the coming decade. To build 3.0 GW of utility scale wind and 1.4 GW of utility scale solar, it is estimated that 750 wind turbines and 3.5 million solar panels will be required by 2030.[51] The scale of the task will require New Zealand to have a resilient clean energy supply chain in place, to avoid unnecessary cost impacts and disruptions to new renewables development. A skilled, clean energy workforce will also need to be mobilised to deliver clean energy projects across the full length of the supply chain.

Exhibit 30: **4.8 GW in utility-scale renewables additions required to meet 2030 system needs**



Note: Assumes capacity factors of 95% for geothermal, 40% for wind, 20% for solar; Capacity does not include battery storage systems or DER/small-scale generation types.

Source: Concept Consulting modelling, BCG analysis

48 That is hydro, geothermal, wind, and utility solar farms

49 It is assumed that slower starting units (including the Huntly Rankines and the Taranaki Combined Cycle Plant) as well as the Te Rapa cogeneration plant will close by 2030, in line with modelling in Section 6

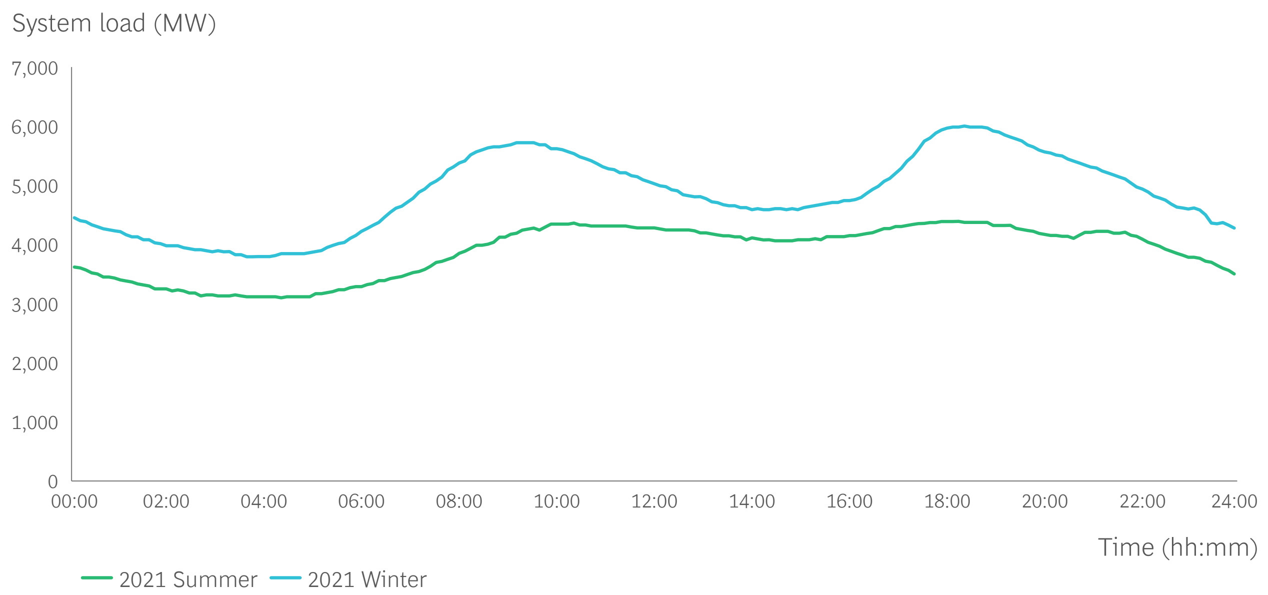
50 176 MW worth of old wind turbines (likely to be replaced/repowered, with new consents required), and 125 MW of Wairakei geothermal that will be decommissioned as part of Contact Energy's broader GeoFuture plans (which will result in an 80 MW net increase in renewable capacity).

51 This assumes the average capacity of a wind turbine is 4 MW, and the average capacity of an individual solar panel is 400 W.

Challenge #2: Peak demand

The load on New Zealand's electricity grid is at its highest in winter mornings and evenings. At these times, sufficient reliable sources of electricity need to be available to meet this peak demand (see Exhibit 31).

Exhibit 31: Typical summer and winter daily load profiles



Source: Transpower, BCG analysis

After a decade of relative stability, peak demand is rising once again—in August 2021, a new record for peak demand was set at 7.1 GW across the North and South Islands (see Exhibit 32).[52]

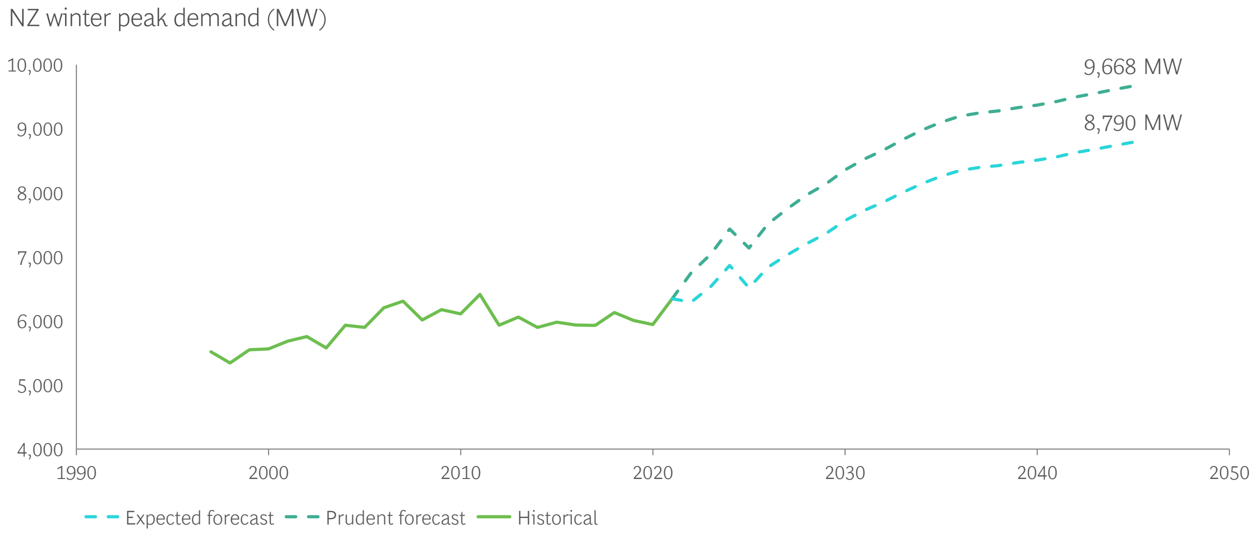
Exhibit 32: New Zealand weekly demand peak

Source: Transpower, BCG analysis

52 Transpower, Security of Supply Assessment 2022, 2022

In its latest Transmission Planning Report 2022, Transpower forecasts that expected peak demand will increase by 19% by 2030 and 34% GW by 2040, creating the need for additional peaking capacity (see Exhibit 33).[53]

Exhibit 33: Transpower's forecast increases to peak demand



Source: Transpower, BCG analysis

Section 5.4 outlined 3 important aspects of changing peak demand dynamics in future: peak demand will increase due to electrification, meeting peak demand will become more challenging with more intermittent generation as it will require increasingly fast-start peaking resources to balance dynamic changes in supply, and the difference between the load demanded from the system in the day versus the evening will increase as more solar enters the system.

The changing profile of future residual demand will need to be addressed through capacity additions and robust operational management of the system. A reserve mechanism already exists within the electricity market. It holds enough reserve capacity to cover the largest credible contingent event—usually either a tripping event at Huntly Power Station or a failure of a HVDC cable. These reserves must be able to ramp up at short notice and often take the form of partially loaded or synchronised (i.e., spinning) turbines. In future additional reserves will likely be required to cover unexpected declines in intermittent generation.

However, if system capacity expansions fail to keep pace with peak demand growth, the future equity and security of New Zealand's electricity supply could be at risk. While existing and committed generation is sufficient to uphold system security out to 2024, beyond this further capacity additions and/or additional demand response will be needed to meet peak capacity.[54]

Under the demand conditions of Transpower's Accelerated Electrification scenario, Transpower's 2022 Security of Supply Assessment estimates that the loss of Huntly's Rankine units will require close to 2 GW of additional capacity above current volumes to meet North Island security standards in 2030, while the complete absence of thermal baseload and peakers in New Zealand will need closer to 2.5–3 GW of additional North Island capacity to safely meet winter peak demand (see Exhibit 34).[55] Constrained gas supply could further accelerate the derating of thermal firming generation, requiring capacity additions to be brought forward.[56]

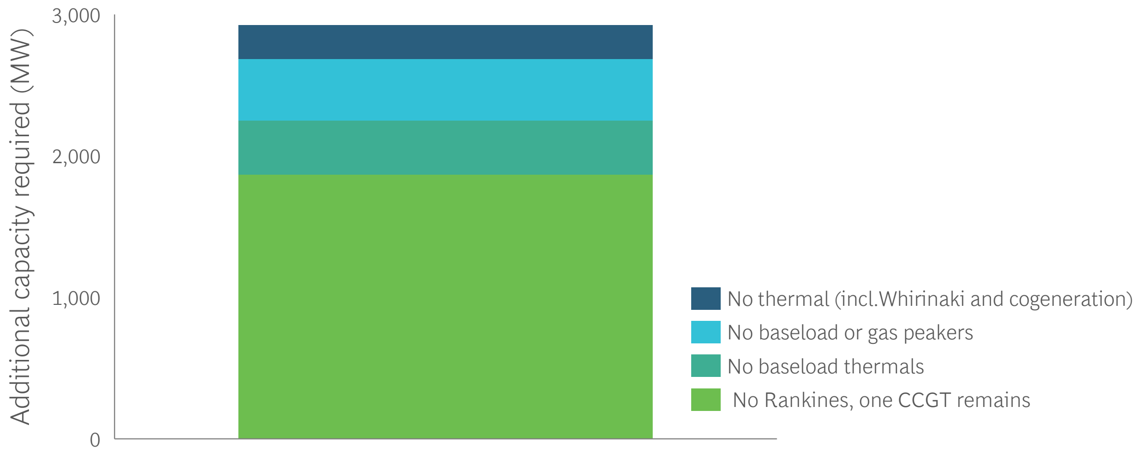
53 Transpower, Transmission Planning Report, 2022. Note these numbers include a Tiwai exit assumption in 2025 and are based on the average peak for the highest 140 half-hourly demand periods rather than the highest peak.

54 Transpower, Security of Supply Assessment 2022, 2022

55 Peakers refer to thermal power plants that can ramp up (and down) quickly to meet demand peaks, hence their names. Peakers today typically use gas, however there is potential for biofuels (such as biodiesel or biomethane) to be used in the future.

56 Transpower, Security of Supply Assessment, 2022

Exhibit 34: **Up to 3,000 MW in additional North Island capacity required to meet peak winter capacity margin security standards in 2030**



Source: Transpower 2022 Security of Supply Annual Assessment, BCG analysis

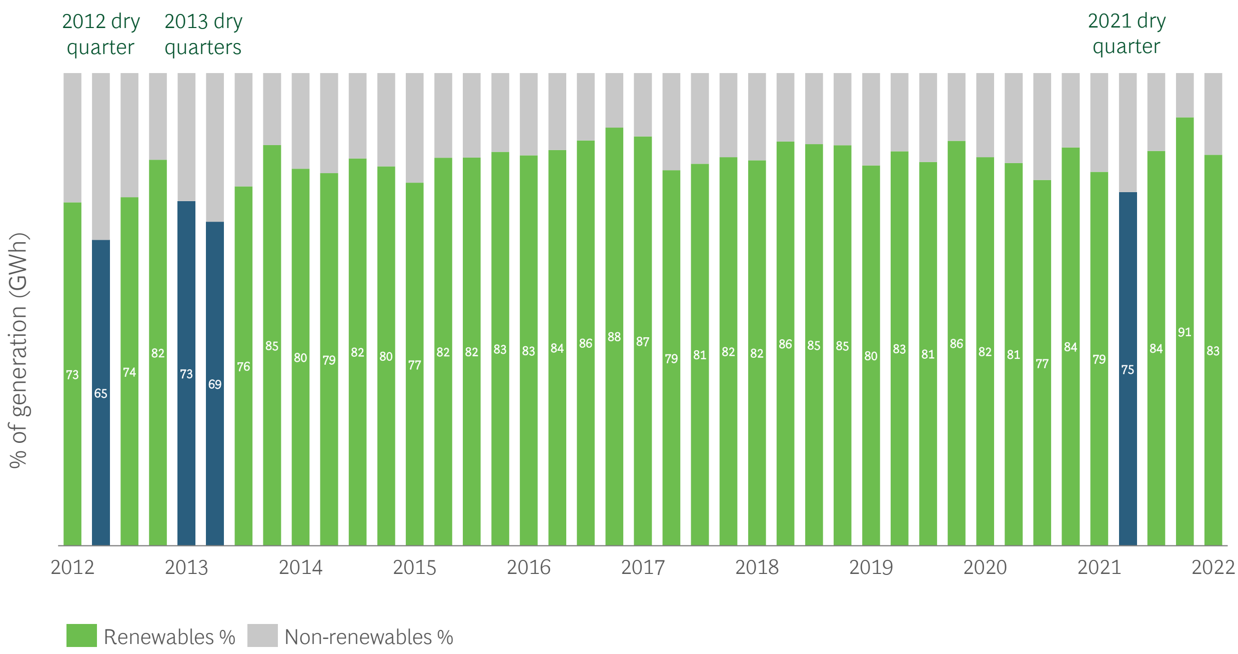
Challenge #3: Dry years

During periods of low rainfall, there is a risk that New Zealand's hydro-dominated power system runs out of energy to meet electricity demand during what is known as a 'dry year'. The dry year challenge tends to seasonally materialise over winter, where lower dam inflows due to lack of snow melt lead to diminished hydro lake levels, and colder temperatures demand higher space and water heating loads from the grid.

New Zealand's hydro capacity is shallow—even when filled to capacity, the country's hydro dams can only provide up to 6–8 weeks' worth of electricity at any given time. As such, the power system has historically depended upon slow-start thermal generation to cover any hydrological gap unable to be filled by renewables. For example, in the winter of 2021, bottom decile hydro inflows were experienced in the first half of the year due to a La Niña event. In combination with constrained gas supply, this necessitated higher rates of coal burn from Huntly power station, as well as the curtailment of large industrial gas and electricity consumers, to bridge a potential energy gap.[57] Although the winter turned out to be one of the wettest on record, the firming response required from Huntly caused the power system to fall to 75% renewable in the June quarter—the lowest contribution from renewables since 2013 (see Exhibit 35).[58]

57 Transpower, Security of Supply Assessment 2022, 2022
58 Transpower, Whakamana I Te Mauri Hiko: Monitoring Report March 2022, 2022

Exhibit 35: **New Zealand renewable generation**



Source: MBIE, BCG analysis

The dry year management provided by New Zealand's thermal assets has so far been enough to avoid an actual energy shortage. Even when winter margins were at their tightest in 1992, and the country entered a conservation campaign that asked residential consumers to constrain their electricity usage, the power system continued to function without running out of energy.

The dry year challenge differs from peak demand in that it is an energy, rather than a capacity, problem. While enough capacity needs to exist in the system to meet the daily peak, dry years require enough energy to be available to satisfy demand.

New Zealand's energy transition is also exacerbating the dry year problem. As the value of slow start thermals for meeting peak demand declines due to the need for fast-start resources, these plants will be increasingly reliant on revenue from dry years which occur infrequently. As outlined in Section 5.4, the potential decrease in thermal generation capacity that may occur as a result will require a combination of renewable overbuild, demand response, and/or long duration storage to meet dry year energy. Growing electricity demand from electrification will tighten energy margins further. Under Transpower's Accelerated Electrification scenario, existing and committed pipeline resources are enough to maintain national winter energy margins above market security standards out to 2027.[59] New generation commitments will extend this date.

59 Transpower, Security of Supply Assessment 2022, 2022

Challenge #4: Networks

Investment in electricity networks will need to increase significantly to enable electrification and renewable energy.

A significant number of large-scale renewable power stations will need to be connected to the transmission grid over the next 30 years, including 4.8 GW in the next 8 years according to Concept Consulting modelling. New core grid interconnections will be required to enable these new connections and electrification. Historically, transmission connections have been in very large, centralised power stations, which has kept the number of required connections low and has enabled greater predictability in the associated core grid upgrades required. As the pace of change accelerates, the future needs of the grid will become more uncertain. Annual investment of about $1 billion in transmission is needed to enable renewable generation and electrification.

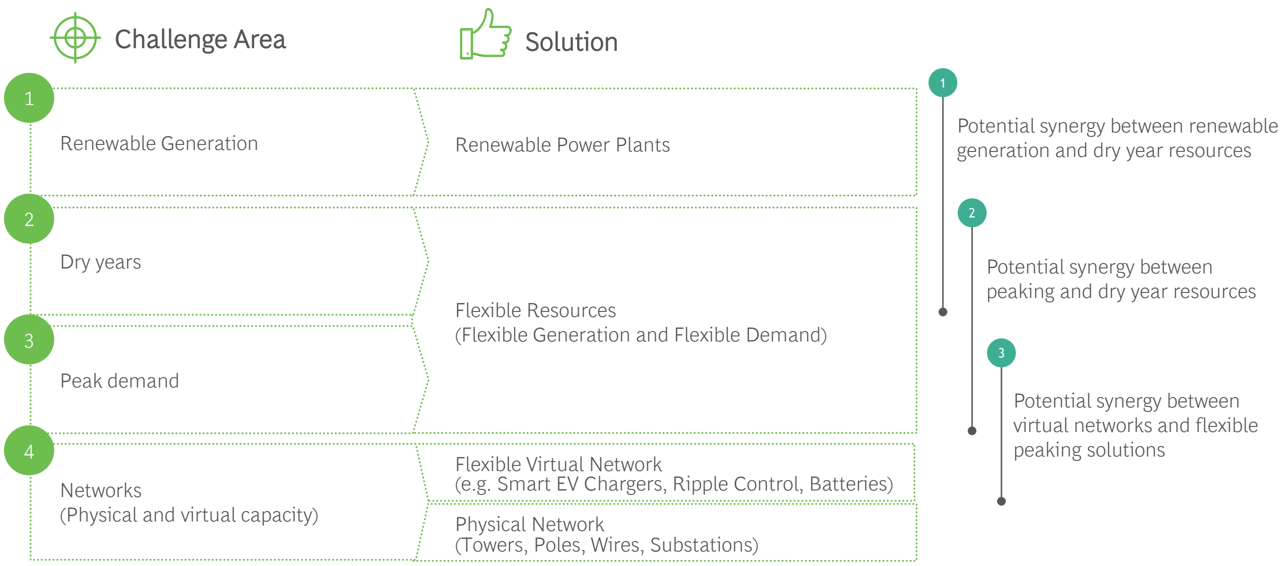
The distribution network will be critical for enabling new electrification and the resulting demand growth. Through rapid electrification of transport, demand will increase at the household and street level, having broader implications for the entire network. Process heat electrification will lead to larger, but more localised areas of step change demand, which could trigger the need for new investments. To enable electrification (primarily) and renewable generation (secondarily), a ~30% increase in distribution spend to an average of $2.4 billion per year to 2050 is needed.

As the number of distributed energy resources (DER) increase more complex, multi-directional electricity flows will emerge. Section 5.4 outlined how system smarts will be required to manage this. Investment in distribution system smarts like LV network visibility and operations systems like Advanced Distribution Management Systems (ADMS) will assist with developing an integrated system, capable of coordinating millions of resources. This will enable demand-side participation and management of multi-directional flows across the future network.

5.6 The importance of whole-of-sector thinking across the 4 energy challenges

Integrated systems thinking will improve outcomes, identifying synergies between challenges and solutions (see Exhibit 36). We explore some of these synergies below.

Exhibit 36: **Benefits of whole-of-sector approach**



1. Synergies between renewable generation and dry year

As the cost of new wind and solar continues to decline rapidly over the longer term and the increasing carbon price continues to make fossil fuel generation less attractive, it will become increasingly viable to 'overbuild' renewables. Renewable overbuild leads to some surplus energy in a normal year, but enough energy in a dry year.

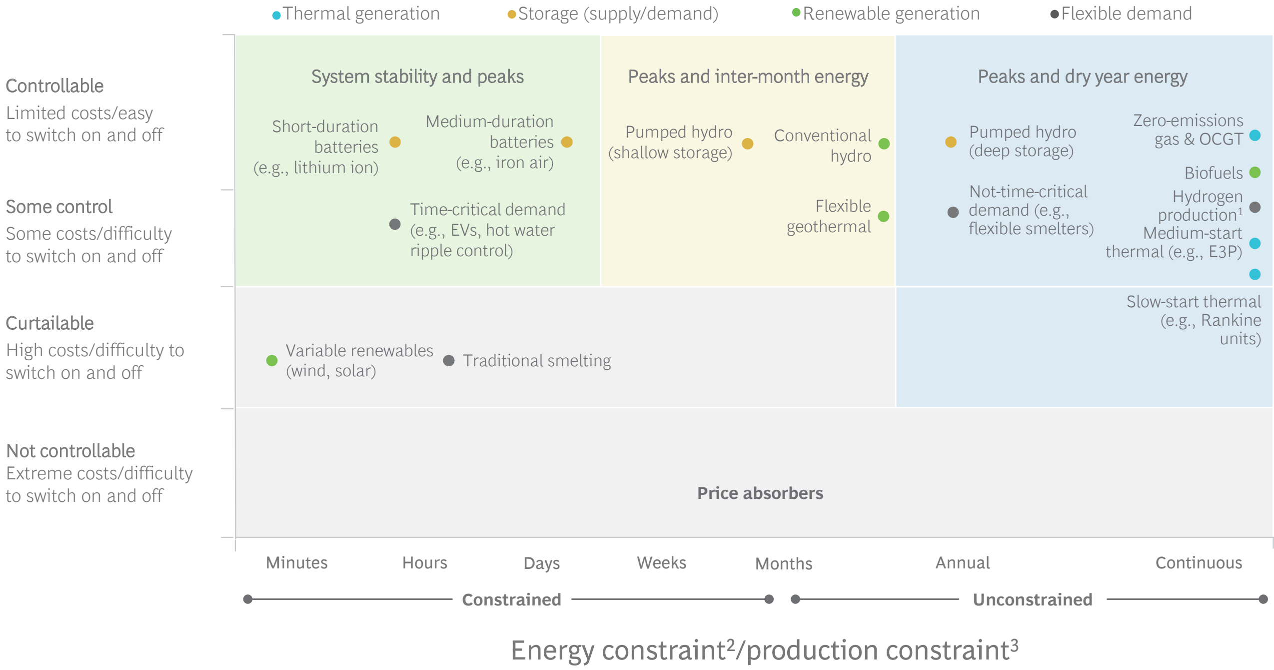
This needs to be tempered with the acknowledgement that overbuilding solar and wind generation will depress the price that these resources can capture in the market, which may dissuade investment. Nevertheless, while the exact level of overbuild is uncertain, it is likely that some overbuild will emerge in the system by 2030.

2. Synergies between peaking and dry year flexible resources

In the past, New Zealand's electricity sector has traditionally relied largely on fossil fuel generation to provide adequate electricity supply during peaks and dry years. However, as the system transitions to more intermittent renewables, various new technologies will also have to provide this backup supply for different depths and durations. Some technologies may be able to support both peaks and dry years, while others may only be able to support one of these challenges. As more solutions become viable, it will be important that these solutions can still satisfy the needs of the system.

Exhibit 37 below outlines different types of resources by controllability (i.e., flexibility) and energy/production constraint (i.e., duration of services they can provide to the system). In time, new technologies including short-, medium-, and long-term energy storage will develop, demand-side participation will increase, and zero-emissions thermal generation options will emerge. We expect that a confluence of these technologies will enable New Zealand to meet future peak and dry year needs.

Exhibit 37: Illustration of how controllability and duration constraints determine the system needs different energy solutions can address



Source: BCG analysis.

1 Controllability dependent on hydrogen storage, offtake obligations, and hydrogen carrier (if relevant). For example, ammonia plants can be turned off but have long response times. 2 Duration of continuous operation by the power plant before it runs out of energy supply. 3 Duration of the energy user's ability to forgo energy consumption before it needs to consume again (e.g., to meet customer demands).

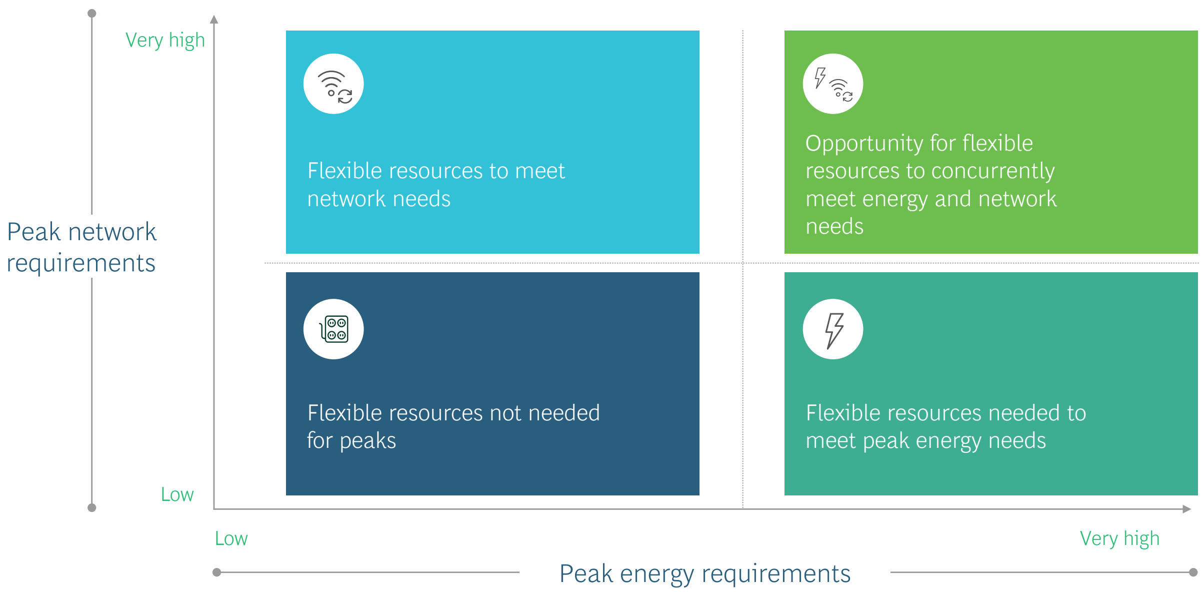
3. Synergies between virtual networks and flexible peaking resources

Electricity networks are largely built to manage peak flows of electricity. Similarly, the energy system needs to have the capacity to provide energy at peak times. As a result, there is the potential for several resources to alleviate peak demand on networks and the energy system concurrently.

The degree to which this occurs depends on the degree that network peaks and energy peaks coincide. As the energy system becomes more dynamic in future, with regional intermittent generation fluctuations and regional demand-side dynamics like EV charging patterns, it is likely that there will be times where network peaks and energy peaks do not always align.

However, there are still likely to be a number of periods when these peaks do coincide and flexible resources, particularly those embedded in distribution networks, can provide important services across both electricity networks and the energy system. This is illustrated in Exhibit 38 below.

Exhibit 38: **Illustration of how whole-of-sector thinking can enable co-optimisation of resources to meet system needs more efficiently**



If policy, markets, and regulations can efficiently coordinate these flexible resources to meet system needs, it could unlock up to $10 billion in NPV savings by 2050.

Illustration of possible solutions to meet the 4 challenges

There are several technological solutions that can address more than one of the key challenge areas concurrently. Key stakeholders are already undertaking initiatives to address these challenges, including developing technology solutions, as seen in Exhibit 39.

The list of solutions above is not exhaustive – many players are independently pursuing projects to address capacity, energy adequacy, and network issues. These solutions address the 4 challenges in different ways, which suggests that a portfolio-based approach may be required to smoothly decarbonise the energy sector. Several pieces of research are exploring solutions to New Zealand's energy transition challenges: the Government is developing an Aotearoa New Zealand Energy Strategy and has the New Zealand Battery Project and a Gas Transition Plan underway, while the Market Development Advisory Group (MDAG) is exploring electricity market options for a 100% renewables grid.[60, 61]

60 Ministry for Business, Innovation and Employment, Gas Transition Plan, 2022
61 Electricity Authority, MDAG 100% renewables project, 2021

Exhibit 39: Technologies and solutions available to address 4 challenges

Solution	Example	New gen.	Peak demand	Dry Year	Physical network
Large-scale pumped hydro	Lake Onslow could be capable of storing ~5 TWh of dry year cover. It could have a similar capacity to Huntly's 3 Rankine units but would be able to provide this capacity as a fast start resource.	◑	◑	●	
Small-scale pumped hydro	Small-scale pumped hydro located in the North Island could address peak demand and energy adequacy. While it would be able to provide important North Island peak capacity, it is unlikely that North Island pumped hydro could provide the same depth of inter-year energy storage as Lake Onslow.	◑	◕	◕	
Renewables with storage	Aurora Energy and solarZero have partnered to build and operate flexible residential solar and battery systems, that could increase electricity supply during peak demand, and provide a lower-cost, non-network alternative to $25 million worth of grid upgrades.	◕	●		◑
Overbuild of renewables	New renewables, such as offshore wind, can increase the amount of generation available. For example, the NZ Super Fund and Copenhagen Infrastructure Partners are exploring offshore wind's potential in Taranaki. The first 1 GW stage could produce 4500 GWh annually with 60-70 fixed wind turbines by 2030.	●	◑	●	
Biomass	Genesis is looking to trial the use of black pellets at Huntly to power its Rankine units. This dry, energy-dense fuel provides a low carbon alternative to coal, in meeting both baseload and peak demand needs, and is able to be stored.	●	◑	●	
Biofuels (inc. biogas)	Biodiesel, for example from tallow or waste cooking oil, can serve as a low carbon fuel. New Zealand's agricultural resources also mean biomethane has the potential to be used in gas turbines, parrticularly as a peaking fuel.	●	◑	◑	
Flexible geothermal	Flexible geothermal can provide additional baseload power and is being considered by the New Zealand Battery Project as a potential dry year solution.	●	◑	●	
Gas peakers	Huntly's OCGT unit uses gas, and can ramp up or down to meet peak demand. Its ability to provide baseload generation means it also serves as a valuable dry year contingency resource.		●	●	
Industrial demand response	Demand response technology could be used at Tiwai Point (or an equivalent large-scale consumer of electricity, such as a data centre), which would allow large-scale users to respond during peak demand and dry year periods. Southern Green Hydrogen, a joint project between Contact and Meridian, is investigating the feasibility of a large-scale production facility in Southland, with its electrolysers designed to flex production during dry hydrological conditions and peak demand periods.		●	◕	
Distributed demand response	The aggregation of smaller-scale demand response across small-scale (residential, commerical) energy consumers can help to balance the power system in real-time and curtail energy consumption during tight demand-supply conditions.		●	◔	◑
Batteries (short duration storage)	Short-duration batteries can help to address peak demand and to maintain key power system characteristics like voltage and frequency (for example, the current Transpower voltage support RFP could be met by a battery as a non-transmission solution). Meridian plan to build a battery with at least 100 MW as part of the Ruakaka Energy Park north of Auckland.		●		●
Batteries (mid duration storage)	Mid-duration storage can help ensure intra and inter month resource adequacy between peak demand and dry year requirements. Other storage opportunities exist with compressed air, flow batteries etc.		●	◑	●
Extra network capacity	As part of its Net Zero Grid Pathways work, Transpower is considering whether to replace, upgrade, or build a new HVDC cable linking the North and South Islands. This will increase the ability of South Island hydro to firm North Island renewable generation.		●		●
Dry year options contracts	In August 2022, Genesis announced its Market Security Options, which would allow interested parties to call on pre-determined thermal capacity, particularly during dry years. This would allow gentailers, retailers, or other buyers of wholesale electricity to mitigate dry year risk.			●	

● Solution ◑ Partial solution

6 Key findings and modelling

The energy sector must make significant decisions as New Zealand progresses further toward net zero. These decisions include the ongoing role of gas in energy supply, the pursuit of hard renewable electricity targets, the role of electrification, and the future electricity generation technology mix. All these decisions have consequences for New Zealand's energy equity, security, and sustainability.

In this section we:

Outline bespoke modelling of 5 illustrative pathways the electricity sector might take to 2050 and the key findings of this modelling.

Identify the pathway that delivers the greatest overall decarbonisation benefits to the New Zealand economy while maintaining energy affordability and reliability.

Answer 9 fundamental questions that underpin the future of the New Zealand electricity sector.

Modelling 5 possible pathways for New Zealand's electricity sector

We analysed how New Zealand's electricity sector may play out in the future. This included conducting bespoke modelling to determine the optimal representative pathway to decarbonise the electricity sector and adjacent sectors by 2050.

6.1 Our 5 Pathways

To consider the future state of the electricity sector, we constructed 5 possible pathways:

Pathway 1: Business-as-usual
Business-as-usual activity and investment drives close to 100% renewables by 2030 with a high uptake of electrification, however this pathway doesn't strongly harness smart technologies (e.g., batteries and distributed energy resources) and relies on peaking thermal and lower levels of demand response

Pathway 2: Smart system evolution
Broad alignment and a whole-of-system view (including consumers) encourages a smart transition, including use of batteries, distributed energy, and demand response, to drive close to 100% renewables by 2030, with a high degree of electrification

Pathway 3: Renewable energy pioneer
A mandated target leads to 100% renewable electricity by 2030, aided by a high uptake of smart technologies (e.g., batteries and demand response), an uptick in the amount of intermittent generation capacity built, and biofuel peakers

Pathway 4: Mega infrastructure build
Government supports achievement of 100% renewables by 2030, with pumped hydro Lake Onslow playing an important role, particularly in dry years

Pathway 5: Green export powerhouse
Up to double New Zealand's electricity needs are generated by renewables, with excess electricity used to generate hydrogen for export or green products (i.e., green aluminium). New Zealand's renewable electricity generation serves as a source of competitive advantage and prosperity for the country

One of the key sensitivities in this modelling is the assumed construction cost of pumped hydro at Lake Onslow. We have modelled the facility to have a capacity of 800 MW and a cost of $6.2 billion, in line with our benchmarking of pumped hydro costs globally (see Section 6, Question 4). In acknowledging that the construction costs are uncertain, but an important factor, the implications of low and high case constructions costs are also discussed in Question 4.

The below table (Exhibit 40) describes the variables that have been defined exogenously (outside of the model). Other variables such as the uptake of electrification, wholesale electricity price, and renewable generation mix by technology type are defined endogenously (i.e., output by the model as opposed to being pre-determined).

Exhibit 40: 5 pathways to cover possible states of future sector

	Pathway name	Smart demand use	100% renewable electricity target	Lake Onslow pumped hydro	Large-scale overbuild of renewables
P1	Business-as-usual	Low	✗	✗	✗
P2	Smart system evolution	High	✗	✗	✗
P3	Renewable energy pioneer	High	✓	✗	✗
P4	Mega infrastructure build	High	✓	✓	✗
P5	Green export powerhouse	Low	✗	✗	✓

Greatest change from today

These 5 pathways encompass the highest-level directions the New Zealand electricity system could take (noting that there are nuances within each pathway). A pathway where Lake Onslow is built in the absence of a 100% renewable electricity target has not been explored, as it was considered that it will only be built in line with an aspirational target.

It is important to note that *Pathway 5: Green export powerhouse,* assumes a step-change increase in the amount of electricity produced (in the order of 50% more than the other 4 pathways). This pathway was designed to explore the viability of New Zealand operating multiple hydrogen production facilities of significant scale and exporting very large amounts of hydrogen. It is not comparable to single hydrogen production facilities at a smaller scale; our modelling assumes all hydrogen produced will be exported, but we do not explore implications for the global energy market and international emissions in detail in this report, nor do we calculate the potentially significant economic development benefits of Pathway 5.

We assessed pathways against the energy trilemma, specifically the following metrics:

Equity

- Relative **cumulative system cost** (by decade)
- Average time-weighted **wholesale prices**
- Relative annual **household energy bills**
- Network **transmission and distribution costs**

Security

- **Generation stack** by fuel source, including under dry years
- **Capacity stack** by fuel source, including to meet peak demand
- Quantity and cost of **demand response**
- **Overall quantum of generation and capacity** required to 2050

Sustainability

- Annual **energy emissions reductions** (both from electricity generation and electrification)

Modelling approach

BCG partnered with Concept Consulting to conduct bespoke modelling of New Zealand's energy system. They used 2 models to analyse the different pathways and provide the full picture of outcomes:

ORC
Its model of the electricity market (e.g., generation and capacity stack and prices in a given year)

ENZ
Its whole-of-economy model, to model the broader energy system and economy (e.g., model the impact that increased electricity prices could have on EV uptake)

ORC – electricity market model

ORC simulates the interaction of generation and demand across different market scenarios. For a given future market situation scenario (i.e., a combination of what generation has been built, the level and composition of demand, and fuel and CO_2 prices), it models how generation and other resources such as batteries will be dispatched to meet demand.

It models each year chronologically, hour by hour, before the model is refined in an iterative manner using data from 40 historical weather years. This allows examination of how a given combination of supply resources (generation, batteries, etc.) will perform across a realistic range of weather situations (varying hydro inflows, wind, and sunshine) and is combined with a demand forecast to optimise the dispatch of its controllable resources. ORC dispatches hydro generation, thermal generation (where available), storage resources (e.g., batteries), and demand response to find the lowest-cost way to meet demand. Long-term storage is tracked for hydro schemes, considering the effect of inflows, maximum and minimum storage levels, and minimum flow constraints. Gas storage facilities and some other types of long-term storage can also be tracked.

ORC models the North Island and South Island as 2 'entities', linked by the HVDC. The model accounts for the need for instantaneous reserves to cover the potential loss of a major supply asset (e.g., one of the HVDC poles, or a large generator). It also models outages at expected frequencies and durations.

The output for a given market scenario will include prices and total system costs (fuel, CO_2, capital and non-fuel operating costs, and demand curtailment). The model is run iteratively, tweaking the capacity of generation and batteries until an optimal, low-cost solution is found. This iteration also ensures that each type of resource that is developed recovers sufficient revenue to cover its capital and operation costs.

ENZ – broader energy system model

ENZ is a model of New Zealand's emissions-producing economy. It was used by the CCC to set New Zealand's carbon budgets. It has separate modules for agriculture, forestry, waste, energy supply (electricity generation and networks, gas production and networks), transport energy use, and non-transport energy-use (including space and water heating, industrial process heat, steel, cement, petrochemicals, etc.).

It models the extent to which energy needs are met by different technology (or land-use change in the case of agriculture and forestry) in response to external scenarios regarding CO_2 price, oil prices, commodity prices, population growth, etc.

ENZ's integrated modules ensure that outcomes in one part of the economy consistently flow through to others. For example:

- Increased electricity demand due to the electrification of space heating will increase electricity prices and affect all other parts of the economy that use electricity. Increased prices will also affect the future rate of electrification of space heating in subsequent years.
- Switching from pipeline gas for one use (e.g., process heat) will affect gas network prices for remaining users of pipeline gas, which will accelerate any switching from pipeline gas.

Combining ORC and ENZ

ORC and ENZ are separate models with no formal integration.

ORC was run for different pathways and scenarios to model electricity system costs and prices. ENZ was run independently under different scenarios of external drivers (such as the prices of carbon and biomass – the key decarbonisation alternative to electrification for industrial process heat). A range of wholesale electricity prices changes were also an exogenous input to the model. These electricity price changes were used to simulate how rates of electrification for key end uses (industrial process heat, space & water heating, and transport) would vary with electricity price.

A separate integration model took the ORC outputs and ENZ's central projection of emissions reductions for the different parts of the economy. It used the ENZ's electricity price electrification function to model the extent to which rest-of-economy electrification would be different between pathways due to differences in ORC-modelled electricity prices, and consequent variations in rest-of-economy emissions and non-electricity costs.[62]

All of Concept Consulting's ORC and ENZ analysis is based on information from public sources, or information developed independently by Concept Consulting.

62 Rest-of-economy non-electricity costs include items such as oil for transport, vehicle purchase costs, space & water heating appliances, etc.

Similarities across pathways

All 5 pathways have several characteristics in common. Below are the factors that remain constant between our pathways:

1. There is a sharp increase in renewable capacity and generation by 2030. This is a function of the steadily decreasing cost of building renewable generation and batteries, and steadily increasing gas (including carbon) prices over time.

2. Total generation and capacity increase steadily through to 2050, primarily driven by increased uptake of electrification.

3. Except for pumped hydro in *Pathway 4: Mega infrastructure build*, no additional hydroelectric capacity is built under any pathway between now and 2050.

4. Coal is phased out throughout the 2020s and is not present in the generation mix from 2030.

5. All pathways demonstrate the importance of investing in transmission and network upgrades sooner rather than later.

6.2 Modelling outcomes

We have detailed the most relevant findings below, including an overview of system cost, generation stack, capacity stack, demand response, and emissions by pathway. While the system has been modelled to a greater degree of granularity, the findings below focus on 2030, 2040, and 2050 as representative visualisations.

EQUITY

Relative system cost by pathway

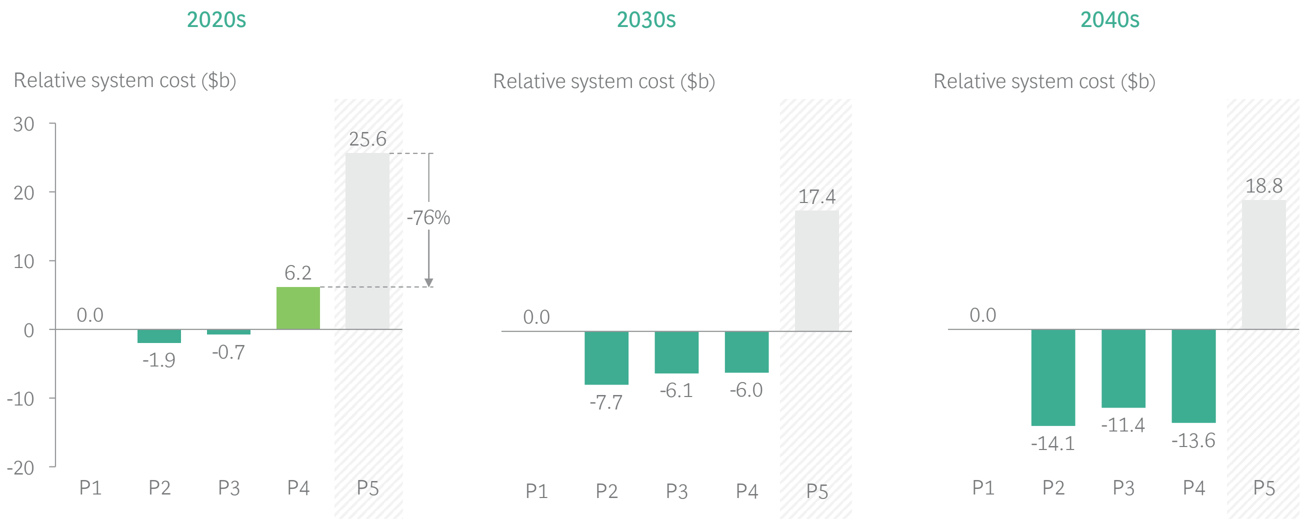
Exhibit 41 details the build-up of system costs, by pathway and over time (all amounts are in real terms). As total generation and capacity increase, so do system costs, driven by increased electrification. Note, these are decadal graphs, and detail the system costs for a given decade.[63]

Pathway 2: Smart system evolution has the lowest system cost of all 5 pathways. It has lower total system costs primarily due to storage and demand response, which reduce the required capacity and network infrastructure and minimise the penalty costs of involuntary demand response.

While the cumulative system costs of *Pathway 4: Mega infrastructure build* are higher in the 2020s than *Pathway 1: Business-as-usual*, this is to be expected as the costs for Lake Onslow's development are incurred in this decade, while the benefits do not accrue until subsequent decades.

The system costs for *Pathway 5: Green export powerhouse* are the greatest. These costs are driven by the significant generation and network costs of building renewables at a large-scale for Pathway 5. The benefits from the additional export revenue of hydrogen production have not been included in this analysis.

Exhibit 41: **Cumulative system cost by pathway relative to Pathway 1**



Source: Concept Consulting modelling, BCG analysis

63 These costs exclude the additional 0.5 GW, 1 GW, and 1.5 GW in 2030, 2040, and 2050 respectively of additional dispatchable supply-side capacity portrayed in *Section 7.3 — Peak demand*

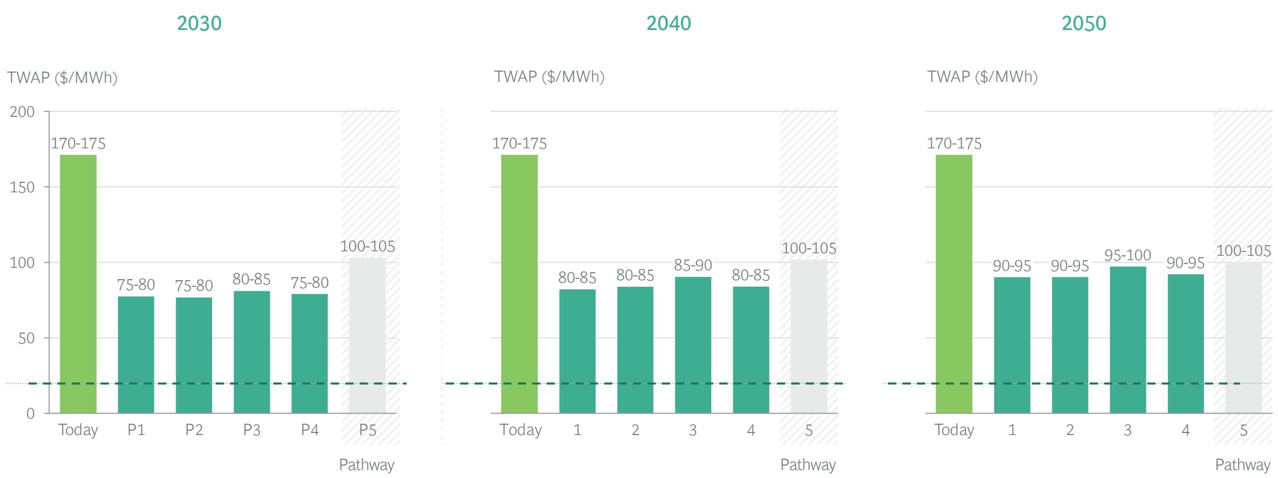
Wholesale costs by pathway

The analysis forecasts that national average wholesale prices will decrease below today's prices observed until 2050 (see Exhibit 42). While prices in real terms increase each decade from 2030, this increase is small, and means that total prices are still much lower in 2050 than today. Electricity prices should decrease over the next decade due to the declining cost of renewable technology and increased system flexibility from storage and demand-side participation.

While the relative differences between pathways are small, there are some differences worth outlining.

Pathway 5: Green export powerhouse sees the highest prices, driven by the cost of such an overbuild of renewable energy. *Pathway 4: Mega infrastructure build* has similar prices to pathways 1–3 in 2030 and 2040, with the availability of stored energy in the form of pumped hydro mitigating against costly sharp spikes in prices offset by a modelled levy to recoup Lake Onslow's construction costs. In each decade, electricity in *Pathway 3: Renewable energy pioneer* is about $5/MWh more expensive than *Pathway 1: Business-as-usual*, *Pathway 2: Smart system evolution* and *Pathway 4: Mega infrastructure build*.

Exhibit 42: Time-weighted average price by pathway



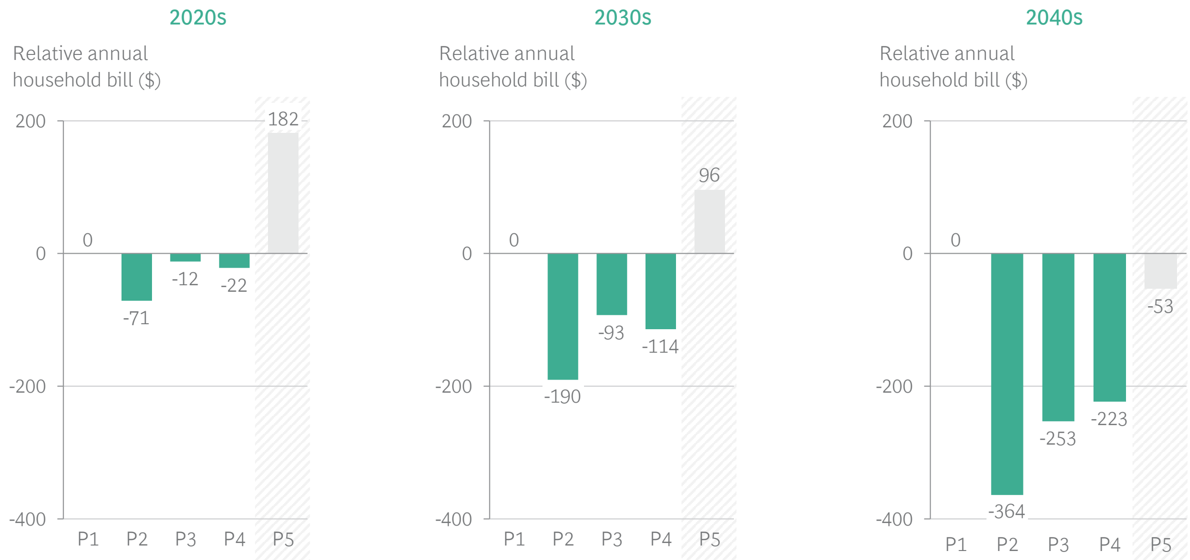
Source: Concept Consulting modelling, BCG analysis

Relative household energy bill

The amount the average household might expect to pay in energy costs each year was modelled for 2030, 2040, and 2050 (see Exhibit 43). This energy bill includes the cost of electricity over the year and transport costs (petrol, diesel, or additional electricity if the household has battery electric vehicles).

Pathway 2: Smart system evolution sees the lowest household energy bill in each decade. While per unit retail electricity prices are forecast to increase slightly through time, this is offset by improvements in energy efficiency, keeping household electricity bills (excluding EVs) relatively flat. The saving in household bills is driven through the electrification of transport. With transport fuel costs being much lower for EVs than ICE vehicles, a pathway with more EVs sees lower household energy bills overall. Pathways 2, 3, and 4 have lower energy costs than the baseline *Pathway 1: Business-as-usual* in all years.

Exhibit 43: **Household energy bills by pathway relative to Pathway 1**

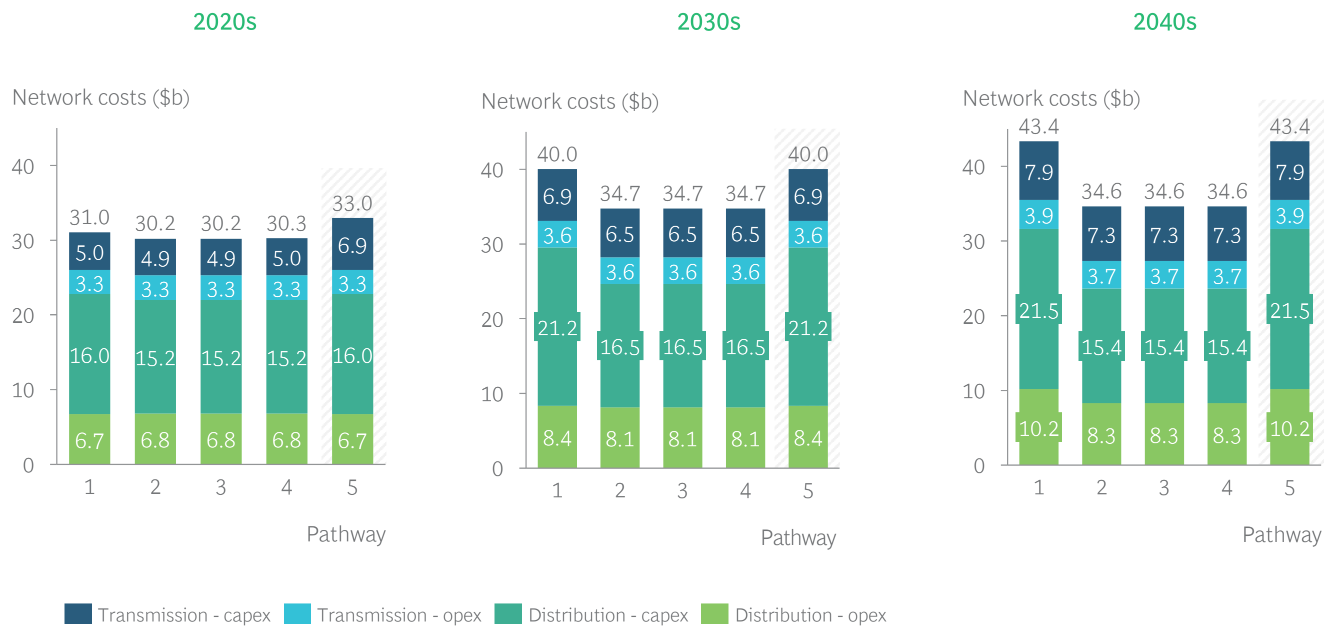


Note: Excludes non-fuel transport costs, ignores impacts of fuel switching
Source: Concept Consulting modelling, BCG analysis

Network costs by pathway

Similarly, cumulative network costs are greatest for Pathway 5, driven by the higher costs of transmission of a greater amount of electricity (see Exhibit 44). Pathways 2, 3, and 4 have the lowest total network costs, driven by greater smart demand and demand response than Pathway 1, which reduces the level of capital investment required in networks. Average annual total network costs are ~30% higher per year than today's levels from 2026–2050 to accommodate a significant build out of network infrastructure to enable electrification and renewable generation.

Exhibit 44: Cumulative network costs by pathway



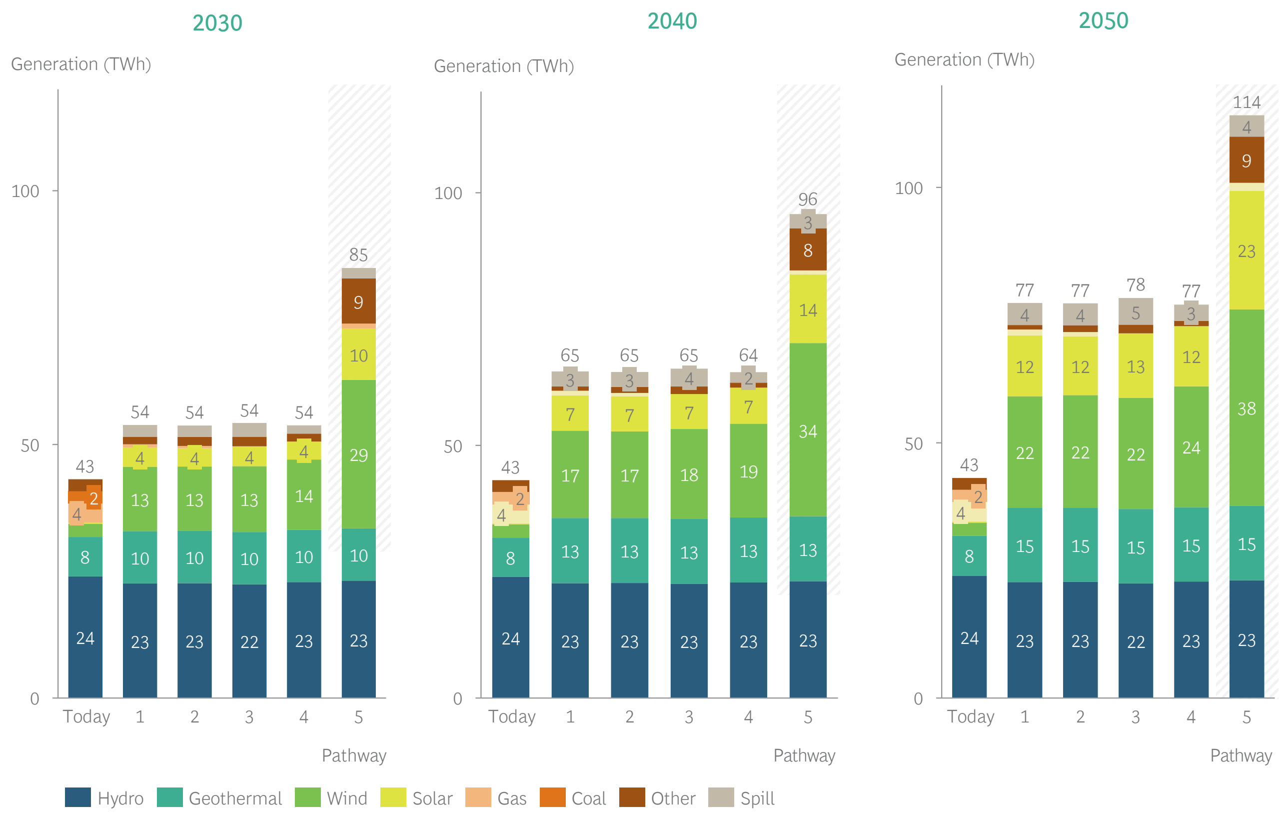
Source: Concept Consulting modelling, BCG analysis

SECURITY

Generation stack by pathway

Exhibit 45 below illustrates the generation stack by pathway for an average year of hydrological inflows. Total generation is flat across Pathways 1–4, a function of demand being very similar. The inclusion of a 100% renewable target in *Pathway 3: Renewable energy pioneer* has a scant impact on the generation stack through time as Pathways 1 and 2 see a sharp uptick in the proportion of renewable electricity through to 2030, reaching 98% by this year. Finally, we see a sharp uptick in the amount of energy generated in *Pathway 5: Green export powerhouse*, driven by large amounts of wind and solar energy. This excess generation would be used to produce green hydrogen or other green products, such as green aluminium. On average, about 50% more electricity is generated in Pathway 5, compared with pathways 1–4.

Exhibit 45: **Generation stack by pathway – average year**

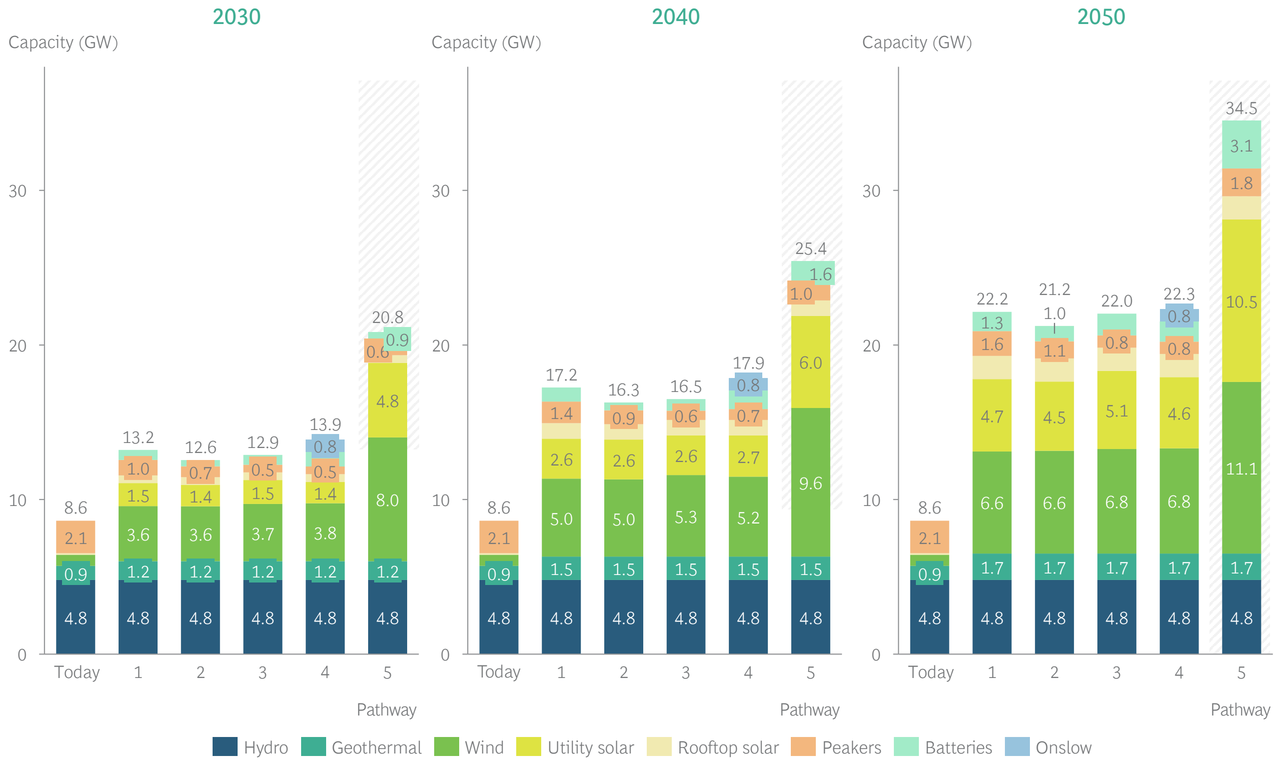


Note: Other includes biofuels, cogeneration, and demand response
Source: Concept Consulting modelling, BCG analysis

Capacity stack by pathway

The capacity stack also grows over time as electricity demand increases (see Exhibit 46). Under *Pathway 5: Green export powerhouse*, considerably more capacity is built to provide much more electricity than pathways 1–4 at a given point in time. Additionally, it is important to note that peakers and batteries are an important component in the capacity mix in all pathways, to alleviate both peaking and dry year challenges. The importance of batteries is seen in 2050, where at least 10% of the capacity mix is provided by batteries, which are more widely available by then and critically important to meeting New Zealand's 2050 electricity needs.[64]

Exhibit 46: **Capacity stack by pathway**



Today's "peakers" stack includes slow start thermal. Peakers are modelled as green peakers under Pathways 3 and 4, and gas under Pathways 1, 2, and 5

Source: Concept Consulting modelling, BCG analysis

64 These capacities exclude the additional 0.5 GW, 1 GW, and 1.5 GW in 2030, 2040, and 2050 respectively of additional dispatchable supply-side capacity portrayed in Section 7.3 – Peak demand

Demand response and costs by pathway

There are 3 types of demand response built into our model:

- **Small-scale demand response** – when appliances, households, and businesses reduce demand during peaks, often in a coordinated or integrated way.
- **Large-scale demand response** – when large users of electricity reduce demand during peaks, such as flexible aluminium production at Tiwai Point (or equivalently, hydrogen production or a data centre).[65]
- **Involuntary demand response** – when users are forced to reduce their demand on the grid during periods when demand outstrips supply. This form of demand response is undesirable and comes with the greatest associated system-wide cost.

For small-scale demand response, we see the greatest quantities in *Pathway 3: Renewable energy pioneer,* albeit with only minor differences between pathways 1–4 (see Exhibit 47). Less small-scale demand response is required in P*athway 5: Green export powerhouse* as plentiful large-scale demand response is available. 280–470 GWh of large-scale demand response is made available in P*athway 2: Smart system evolution* and P*athway 3: Renewable energy pioneer,* depending on the year. As might be expected, large-scale demand response is greatest in *Pathway 5: Green export powerhouse;* having such large hydrogen production facilities for export only makes sense if the facility has some inherent flexibility available. Small amounts of involuntary demand response are called for across pathways (this is a last resort, with a very high associated cost); virtually no involuntary demand response is called for in *Pathway 5: Green export powerhouse*, due to the vast amount of large-scale demand response available.

Exhibit 47: Demand response by pathway

2030

GWh	P1	P2	P3	P4	P5
Small DR	10.6	17.3	21.3	10.1	3.7
Large DR	0	280	300	0	7,430
Invol DR	0.3	0.3	0.2	0.5	0.1

2040

GWh	P1	P2	P3	P4	P5
Small DR	11.9	20.0	33.0	12.2	1.4
Large DR	0	370	410	0	7,490
Invol DR	0.3	0.1	0.1	0.5	0.0

2050

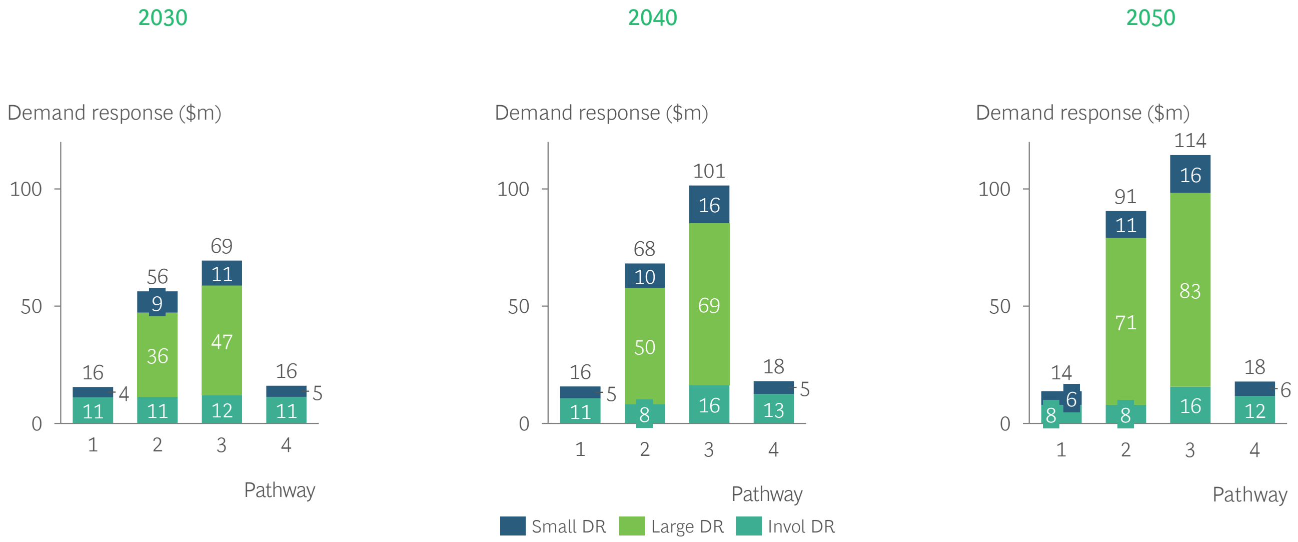
GWh	P1	P2	P3	P4	P5
Small DR	14.0	23.7	34.9	14.2	1.1
Large DR	0	470	460	0	8,18(
Invol DR	0.0	0.0	0.0	0.1	0.0

Source: Concept Consulting modelling, BCG analysis

65 Further work would be required to evaluate the potential for demand response at data centres. Some of these facilities require a reliable supply of electricity.

Exhibit 48 below show the costs of the demand response by pathway. Note, *Pathway 5: Green export powerhouse;* has not been included, as the modelled demand response costs associated with large-scale demand response are high (but have not accounted for the economic value of energy produced for export). We see that demand response costs in aggregate are highest for *Pathway 2: Smart system evolution* and *Pathway 3: Renewable energy pioneer*. This is due to the opportunity cost of lost production (be it aluminium, hydrogen, or data processing), and is not inherently a weakness of pathways 2 and 3. Demand response lowers other costs, such as those of producing very expensive forms of electricity during peak periods. Demand response costs in Pathway 4 are lower as Lake Onslow provides significant levels of system flexibility that reduce the need for demand response.

Exhibit 48: **Demand response costs by pathway**

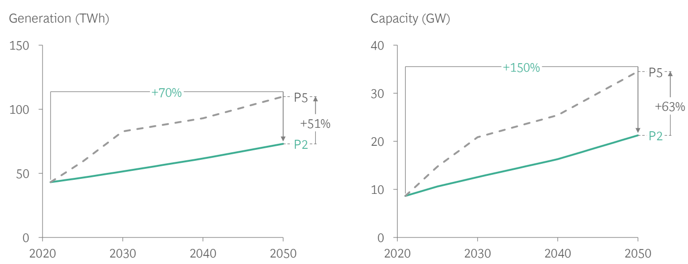


Source: Concept Consulting modelling, BCG analysis

Generation and capacity over time

Exhibit 49 outlines the amount of total generation and capacity required under *Pathway 2: Smart System evolution* and *Pathway 5: Green export powerhouse*. While generation is forecast to increase by 70% in Pathway 2, capacity will need to increase by over 150%. This is because wind and solar have lower capacity factors than generation sources such as hydro, geothermal, coal, and gas, and because peak demand will be significantly higher. Pathway 5 requires significantly more generation (51%) and capacity (63%) compared with the other 4 pathways, in order to supply the modelled demand-intensive industries.

Exhibit 49: **Total generation and capacity over time**



Source: Concept Consulting modelling, BCG analysis

SUSTAINABILITY

Emissions by pathway

When looking at emissions, the most striking observation is the extent to which the electricity sector will reduce emissions, even by 2030 and especially by 2040 (see Exhibit 50). Overall, *Pathway 5: Green export powerhouse* followed by *Pathway 1: Business-as-usual* see the greatest energy sector emissions, due to the amount of thermal generation required and the more sluggish uptake of electrification driven by the associated higher wholesale electricity prices. Pathways 2, 3, and 4 have comparable emissions in each decade.

Electrification will see emissions significantly reduced in adjacent sectors such as transport, industrial processes, and space and water heating in the residential and commercial sectors. These rest-of-economy energy emissions are smallest in *Pathway 2: Smart system evolution*, driven by lower electricity prices across the country. However, this pathway has slightly higher electricity generation emissions than *Pathway 3: Renewable energy pioneer* and *Pathway 4: Mega infrastructure build*.

In terms of emissions from electricity generation, all pathways see at least a 75% reduction by 2030, with all pathways reaching at least 98% renewable electricity by 2030. For pathways 1, 2, and 5 (where there is gas available in the absence of a hard 100% renewables target), there is less than 2 Mt CO_2-e of greenhouse gas emissions from electricity generation even in dry years. Fugitive geothermal emissions become the major source of electricity generation emissions across all pathways, although geothermal's emissions contribution remains limited, at less than 1 Mt CO_2-e each year in a normal hydrological year. The difference in electricity generation emissions between *Pathway 2: Smart system evolution* and *Pathway 3: Renewable energy pioneer* is between 0.2 and 0.4 Mt CO_2-e.

Exhibit 50: **Emissions by pathway**

Rest of economy emissions excludes some non-electricity emissions reduction sources
Source: Concept Consulting modelling, BCG analysis

In summary, this means that there is a clear path towards the electricity and broader energy sector making a significant contribution to New Zealand's emissions reductions efforts. The majority of electricity generation emissions can be abated in the 2020s, and the majority of emissions abated through electrification will occur in the 2030s.

Preferred pathway

Exhibit 51 below highlights some of the most important metrics to compare our 5 pathways against in the year 2030.

Exhibit 51: 2030 | Comparison of pathways against most relevant metrics

		Equity			Security	Sustainability
Pathway name	Description	Relative decadal system cost (v P1)	Nationwide average wholesale prices	Annual household energy bills (v P1)	Involuntary demand Response	Electricity sector CO_2-e emissions reduced
P1: Business-as-usual	BAU activity with limited smarts	-	$75-80/MWh	-	300 MWh	8.5 Mt
P2: Smart system evolution	Batteries, DER, demand response	- $1.9 bn	$75-80/MWh	- $70 *Preferred pathway*	340 MWh	8.7 Mt
P3: Renewable energy pioneer	100% renewables target	- $0.7 bn	$80-85/MWh	- $10	240 MWh	8.7 Mt
P4: Mega infrastructure build	Onslow + 100% renewables	+ $6.2 bn *Costs incurred in 2020s, benefits accrue in later decades*	$75-80/MWh[1]	- $20	540 MWh	8.5 Mt
P5: Green export powerhouse	Excess energy for export	+ $25.6 bn[2]	$100-105/MWh	+ $180	50 MWh	7.5 Mt[3]

1. Includes cost recovery of pumped hydro at Lake Onslow 2. Does not include the revenue recovered from the sale of exported products
3. Does not consider international emissions abated

Source: Concept Consulting modelling, BCG analysis

Compared with the other 4 pathways, *Pathway 2: Smart system evolution* has the lowest system cost, low wholesale prices, the lowest energy bills, modest levels of involuntary demand response, and similar emissions reductions to pathways 1, 3 and 4.

Pathway 4 has a high total system cost in the 2020s, but this is to be expected as the cost of building Lake Onslow is incurred in this decade while the benefits are yet to accrue. Once operational, Lake Onslow delivers benefits to the electricity system, and leads to slightly higher system costs in the 2030s and 2040s than Pathway 2, while delivering 100% renewable electricity under most hydrological years.

Exhibit 52 below highlights some of the most important metrics to compare our 5 pathways against in the year 2050.

Exhibit 52: 2050 | Comparison of pathways against most relevant metrics

		Equity			Security	Sustainability
Pathway name	Description	Relative decadal system cost (v P1)	Nationwide average wholesale prices	Annual household energy bills (v P1)	Involuntary demand Response	Electricity sector CO_2-e emissions reduced
P1: Business-as-usual	BAU activity with limited smarts	-	$90-95/MWh	-	2 MWh	21.1 Mt
P2: Smart system evolution	Batteries, DER, demand response	- $14.1 bn	$90-95/MWh	- $360 *Preferred pathway*	0 MWh	22.2 Mt
P3: Renewable energy pioneer	100% renewables target	- $11.4 bn	$95-100/MWh	- $250	0 MWh	22.3 Mt
P4: Mega infrastructure build	Onslow + 100% renewables	- $13.6 bn	$90-95/MWh[1]	- $220	150 MWh	22.4 Mt
P5: Green export powerhouse	Excess energy for export	+ $18.8 bn[2]	$100-105/MWh	- $50	0 MWh	20.8 Mt[3]

1. Includes cost recovery of pumped hydro at Lake Onslow 2. Does not include the revenue recovered from the sale of exported products
3. Does not consider international emissions abated

Source: Concept Consulting modelling, BCG analysis

Again as with the 2030 scorecard, when compared with the other 4 pathways, *Pathway 2: Smart system evolution* has the lowest system cost, low wholesale prices, the lowest energy bills, no involuntary demand response, and similar emissions reductions when compared with pathways 3 and 4. *Pathway 4: Mega infrastructure build* has the lowest total energy emissions in 2050, with 0.2 Mt CO_2 more emissions abated compared with *Pathway 2: Smart system evolution*.

While Pathway 5 comes with significant potential to abate emissions internationally, it does come at a large cost. As the benefits of exports (both financial and in terms of international abatement) have not been modelled, it is difficult to assess the merits of the pathway in isolation based on these metrics above alone.

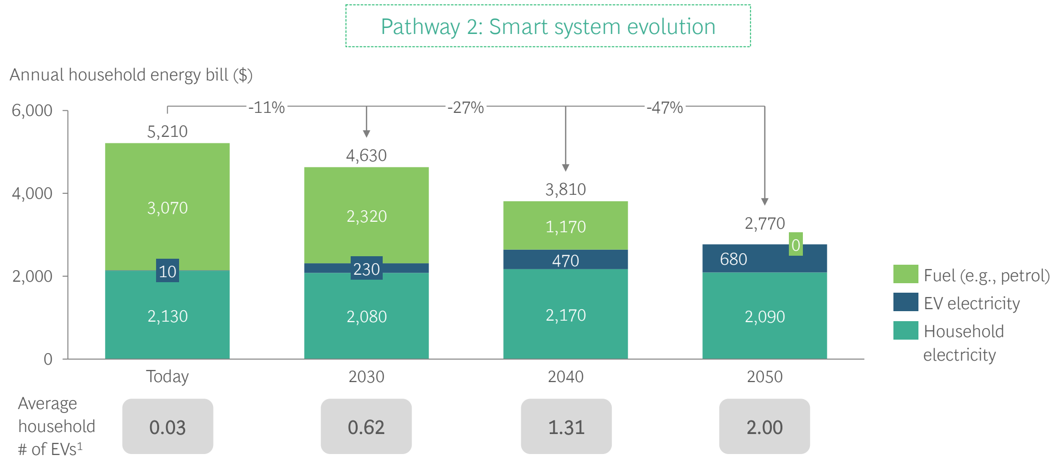
Pathway 2: Smart system evolution is identified as the preferred pathway. If Pathway 2 is selected, in the longer term there is the possibility to pivot to *Pathway 3: Renewable energy pioneer*, whereby gas is displaced by biofuels (such as biodiesel or biomethane). With 98% renewable electricity achievable by 2030 onwards, small quantities of biofuels could be used to achieve 100% renewable electricity around 2040 with only very small incremental additional system costs incurred.

We now consider how P*athway 2: Smart system evolution* performs against the 3 elements of the trilemma: equity, security, and sustainability.

Equity

For our preferred pathway (*Pathway 2: Smart system evolution*), household bills decrease by 11% by 2030, and by 47% by 2050 (see Exhibit 53). This steady decrease each decade is driven by the decreasing cost of transport (e.g., petrol, diesel, electricity) as the proportion of EVs owned by the average household increases over time. As the average household transitions from 2 ICE vehicles to 2 EVs, the cost of fuel (i.e., non-household electricity but including electricity for EVs) is forecast to decrease by 80% by 2050.

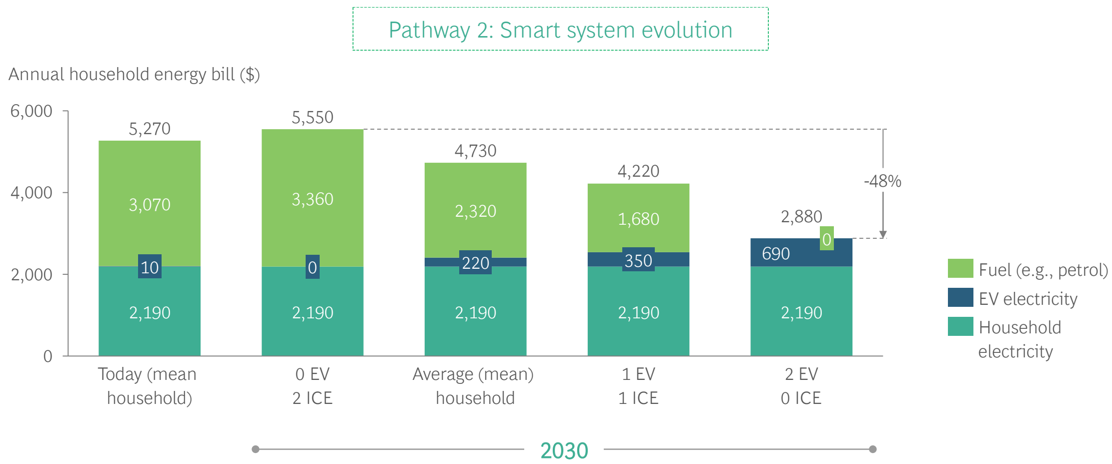
Exhibit 53: **Average (mean) annual energy bills over time for illustrative 2 car household**



1. Illustrative example whereby the average household owns two cars in total
Source: Concept Consulting modelling, BCG analysis

Exhibit 54 below presents a view of the forecast bill for 4 archetypal households in 2030, relative to today: a household with 2 ICE vehicles, the mean household (with 0.6 EVs and 1.4 ICE vehicles), a household with one EV and one ICE vehicle, and household with a 2 EVs. The more EVs a household has, the lower the total household energy bill. Total household bills are 48% lower and transport costs are 80% lower for a household with 2 EVs relative to household with 2 ICE vehicles. This is potentially problematic for equity, as wealthier households that have the disposable income to spend on the upfront capital costs of EVs will benefit from cheaper transport and thus overall household energy bills. While the capital costs of EVs and ICE vehicles should approach near parity in 2030, poorer households are less likely to buy new vehicles, and therefore are likely to be disadvantaged by this ICE/EV operating cost discrepancy for some years.

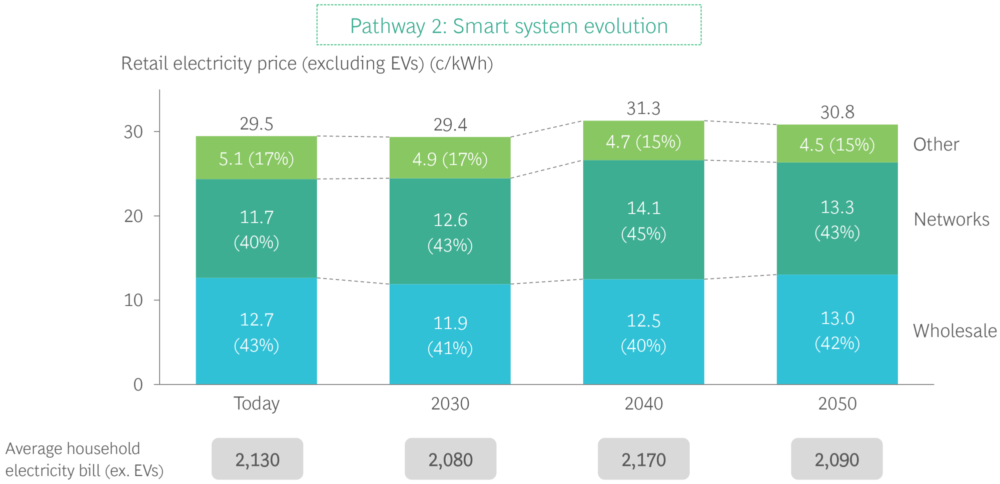
Exhibit 54: **Household annual energy bills in 2030 for illustrative 2 car household**



Source: Concept Consulting modelling, BCG analysis

Exhibit 55 details the split of a household's electricity bill (over the course of a year) by wholesale, network, and other costs. We see a steady, flat retail electricity price over the next 3 decades, with a similar split of wholesale, network, and other costs. The total price rises 6% from 2030 to 2040, due to the investment in networks required, before declining again throughout the 2040s, when the benefits of these smart network investments are realised. In blue at the bottom of the exhibit, and holding all else equal, overall household electricity bills remain relatively stable through time, driven by the improved energy efficiency.

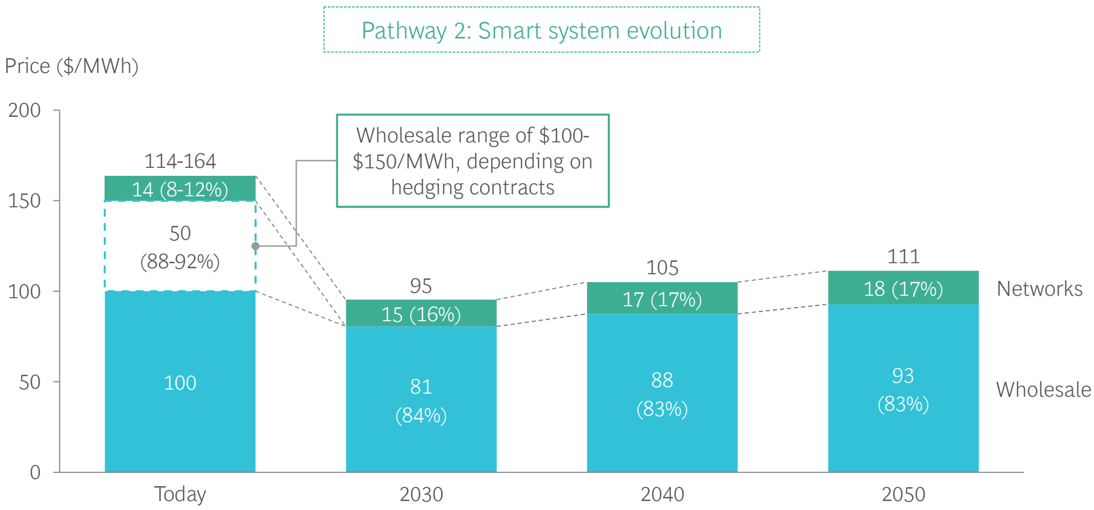
Exhibit 55: **Retail household electricity price (excluding EVs)**



Source: Concept Consulting modelling, BCG analysis

As well as household consumers, we have also considered the breakdown of the electricity bill of an illustrative industrial consumer over time. We have assumed, for simplicity, that this consumer relies on baseload electricity, is connected to the grid, and is in the North Island. The price decreases this decade, before rising again through the 2030s and 2040s. Wholesale electricity remains the main driver of this cost, making up at least 88% of the cost base today and approximately 83% in future decades, although the network component does increase steadily over time, in part to recoup the costs of investing in network infrastructure (see Exhibit 56).

Exhibit 56: **Industrial electricity costs for illustrative, baseload, grid-connected North Island customer**



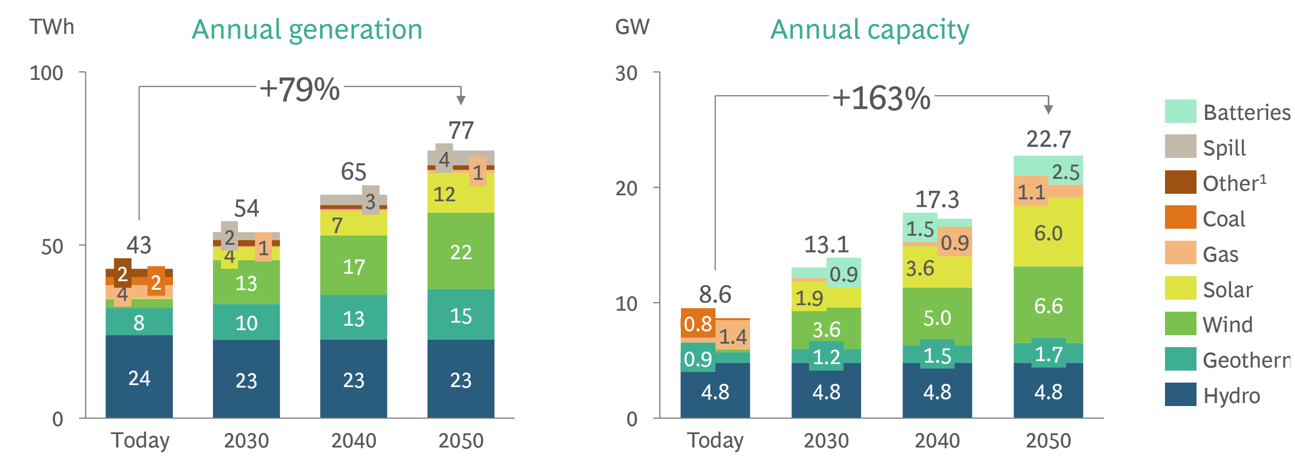
Source: Concept Consulting modelling, BCG analysis

Security

A key aspect of energy security is having enough capacity available to generate electricity when it is required. While Pathway 2 leads to deep decarbonisation and improved affordability, it relies on a significant build out of additional infrastructure.

If the below levels of generation and capacity are not built in time (see Exhibit 57), more thermal power stations will need to be retained to deliver a secure supply of electricity which could be detrimental to both equity and sustainability.

Exhibit 57: Generation and capacity need to increase significantly over next 3 decades



1. Other includes gas co-generation, biofuel co-generation, and diesel

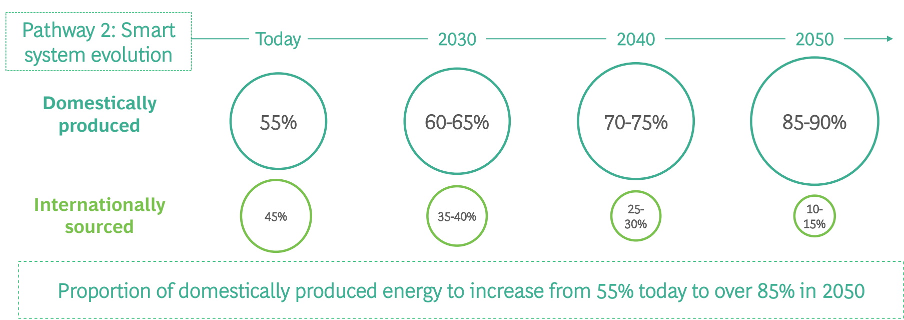
Note: Additional battery capacity of 0.5 GW in 2030, 1.0 GW in 2040 and 1.5 GW in 2050 has been added due to value stacking potential outside of the modelled wholesale market. See explanation on page 124

Source: Concept modelling, BCG analysis

Another key aspect of security is the ability to generate energy from domestically produced sources. This exposes New Zealand less to global supply chain shocks and pricing volatility; during periods of international energy scarcity, New Zealand is still able to produce the requisite amount of energy (including electricity) at an affordable price.

Over time, as the proportion of energy needs met by electricity increases, and as the proportion of electricity met by domestically sourced renewable means also increases, the reliance on international energy imports will reduce. While 45% of energy resources are imported today, only 10–15% will be imported in 2050 (see Exhibit 58). This will mean that New Zealand will be better placed to produce affordable, reliable energy across the economy.

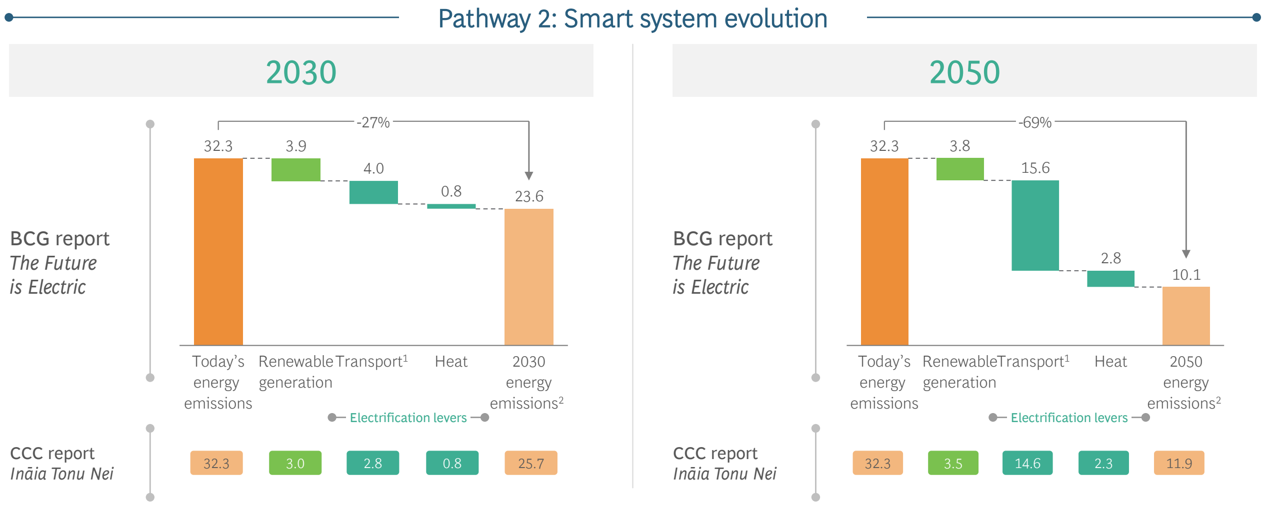
Exhibit 58: Proportion of energy consumed in NZ that is domestically produced



Sustainability

Our preferred pathway delivers significant emissions reductions. From 2030 onwards, 3.9 Mt of emissions beyond today's baseline will be abated each year through renewable electricity generation (see Exhibit 59). An additional 4.8 Mt and 18.4 Mt can be abated each year via electrification of the transport and heat sectors by 2030 and 2050 respectively, which means that the electricity sector is responsible for 8.7 Mt of annual abatement by 2030 and 22.2 tonnes of annual abatement by 2050, or 27% and 69% of today's energy emissions.

Exhibit 59: **2030 and 2050 Mt CO2-e Energy emissions abated through time**



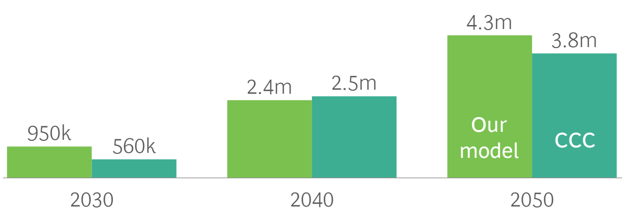
1. Road transport emissions abatement only. Electrification can also abate a smaller amount of non-road transport emissions (e.g., on farm vehicles, construction machinery, rail, air, marine)

2. After the contribution of the electricity sector. Other emissions reductions from biofuels, hydrogen, and energy efficiency gains are likely

Source: Concept Consulting modelling, Climate Change Commission, BCG analysis

One critical assumption to the emissions forecasts in future decades is the number of EVs, which is primarily a function of the price of electricity. Exhibit 60 shows the number of EVs in 2030, 2040, and 2050. In 2030 and 2050, a greater number of EVs are modelled in this report than in the CCC's 2021 *Ināia Tonu Nei* report, which is a contributing factor to the 1.2 Mt and 1.0 Mt more emissions abated in the transport sector in 2030 and 2050 respectively.

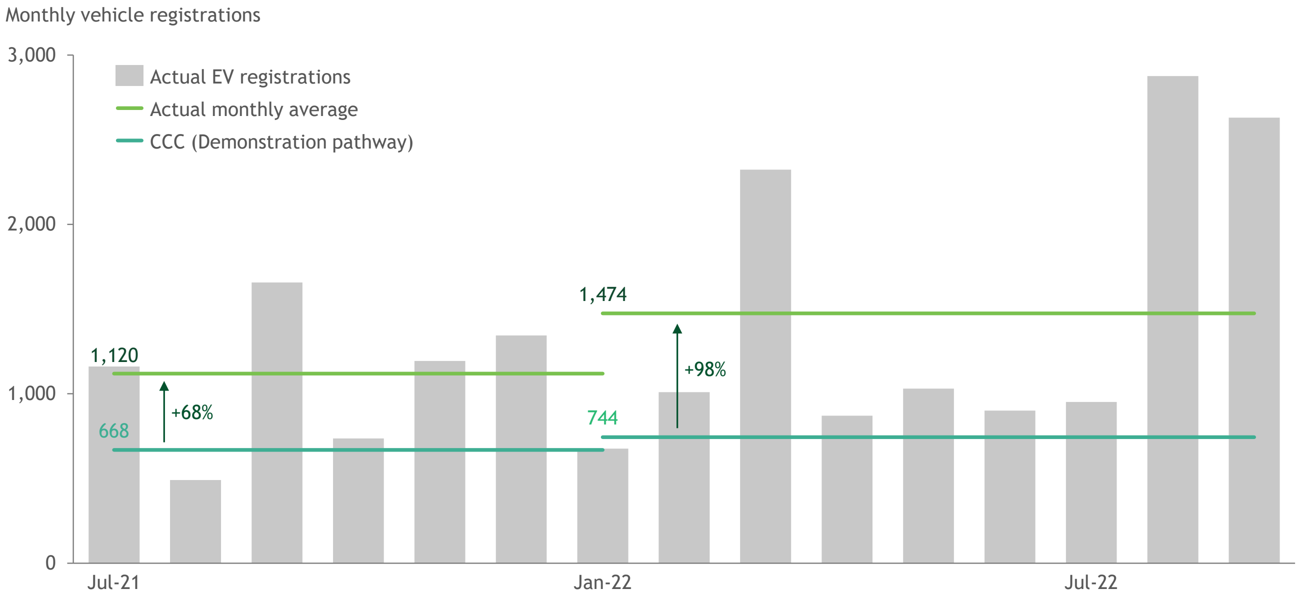
Exhibit 60: **Number of electric vehicles in the modelling:**



Source: Concept Consulting modelling, BCG analysis

This assumption of higher EV uptake is partially informed by the fact that EV uptake has been higher than expected since the *Ināia Tonu Nei* report was released. Exhibit 61 illustrates this.

Exhibit 61: Increase in New Zealand's electric vehicle registrations since July 2021



Note: Includes light passenger and commercial battery electric vehicles
Source: Ministry of Transport, Climate Change Commission, BCG analysis

Evaluation of 9 fundamental questions

This section evaluates 9 questions pivotal to the future New Zealand's electricity sector, taking a holistic, sector-wide approach, drawing on bespoke and existing in-depth research.

Exhibit 62: Nine fundamental questions that underpin the future of NZ's electricity market

1
What are the benefits of pursuing large-scale electrification?

2
To what extent can a smarter, more flexible system assist with meeting peak demand across the sector?

3
Will just-in-time network investments continue to be sufficient in meeting increasing demand?

4
Does Lake Onslow pumped hydro provide the best trilemma outcomes?

5
Will a 100% renewable electricity target lead to the best trilemma outcomes?

6
What role do thermal power stations have a role to play in the future electricity system?

7
What role will electrification and hydrogen play in displacing reticulated natural gas?

8
What are the implications of a hydrogen export facility for the future electricity sector?

9
To what extent should the electricity sector retain optionality, at least through until 2030?

1. What are the benefits of pursuing large-scale electrification?

Modelling showed New Zealand's total annual demand is 51 TWh in 2030. This includes 3.8 TWh from the electrification of transport, 0.9 TWh from the electrification of process heat, and 0.8 TWh from the electrification of space and water heating.

+ Advantages

Electrification can reduce emissions by converting processes that currently rely on fossil fuels to electricity (which is predominantly renewable). In our model, electrification reduces emissions by 4.8 Mt CO_2-e by 2030, and 18.4 Mt CO_2-e by 2050. Electrification drives more than 5 times as much emissions reduction than decarbonising electricity generation by 2050. The Interim Climate Change Committee (ICCC) estimates that each year of delayed electrification will increase New Zealand's cumulative emissions by 1%, and costs by $1 billion.[66]

Electrification can generally be achieved without impacting affordability. This is because electrification is typically more efficient than thermal fuel uses, from an 'energy consumed' perspective. For example, heat pumps require fewer joules of energy to heat a room than gas; heat pumps produce about 3 times more heat

66 Interim Climate Change Committee, Accelerated electrification: Evidence, analysis and recommendations, 2019

than the amount of energy they consume, whereas boilers produce 90% as much heat as energy consumed.[67] At the same time, the capital costs of equipment that runs on electricity (vehicles, process heat systems, heat pumps) are declining year-on-year; for example, capital costs of EVs have decreased by up to 5 times compared with 2010.

Due to the high levels of car ownership in New Zealand, and the overweighted impact of the transport sector on the country's emissions, electrifying vehicles – particularly light vehicles, which are much easier to electrify – represents a significant opportunity to reduce emissions. The lifetime cost savings of EV ownership will be greater than internal combustion engine (ICE) vehicles, and EVs are more readily able to be converted to autonomous vehicles. EVs can charge when electricity is at its cheapest, which can reduce peak capacity by 1.9 GW by 2035 (see Question 2 below).

As discussed in Section 5, the average total cost of ownership of an EV is forecast by the CCC to be $32,770 as opposed to $35,545 for an ICE vehicle by 2030. This means that the average residential electricity price would have to exceed $2,000/MWh for EVs to be less economic to own as compared with vehicles running on petrol.

Process heat accounts for about 8 Mt of CO_2-e emissions annually (9.7% of total), with space heating accounting for about 2 Mt CO_2-e (2.4%). The technology exists to electrify most process heat that require temperatures below 300°C, which currently emit 5 Mt CO_2-e annually. Highly efficient heat pumps are also available today, which could vastly decrease the need for gas and diesel to be used in space heating; heat pumps are the cheapest and most energy efficient way to heat (and cool) homes. Electrifying these sectors can decrease more emissions than decarbonising the electricity sector itself, as well as reduce pollutants released through heating processes — making economic sense when the marginal abatement cost is lower than the carbon price, which is likely to occur soon.

Disadvantages and challenges

There are processes that cannot be electrified affordably. The economic and operational characteristics of heavy transport operators (heavy loads, long distances, and long operational hours) favour synthetic fuels or hydrogen.

The technology for electrifying high-temperature processes is still nascent. Even once the technology is developed, it is likely to be highly expensive to use electricity to reach temperatures above 300°C at scale, and hydrogen may serve as a better alternative for high temperature process heat.

Certain households still have gas connections for heating. With some consumers preferring gas for cooking, and the costs of retrofitting an existing gas-fired home with electric heat pumps, there is some behavioural inertia to overcome. As at March 2022, gas for residential use was 14.4 c/kWh, versus 30.2 c/kWh for residential electricity.[68] Doubling down on electrification now removes the optionality of introducing green gas at scale later and may cause issues for the last remaining users of gas, if maintenance of gas infrastructure ceases.

Finally, the additional electricity required to electrify transport, industry and households could place strain on transmission and distribution networks. However, this can be mitigated through smart charging and demand response. This is covered in more detail in Question 2.

Implications for the roadmap

Electrification will drive large-scale emissions reduction across the transport and heat sectors. It should be encouraged and incentivised to a large extent. It will ensure that most of New Zealand's energy is domestically produced, economic and efficient.

67 In Hyun et al., Boiler efficiency and heat pump COP variations, 2014

68 Ministry of Business, Innovation and Employment, Energy prices, 2022

2. To what extent can a smarter, more flexible system meet peak demand across the sector?

One proposed solution to meet peak demand is to use demand response. An additional solution involves drawing on 'smart demand' whereby users charge their electricity-intensive items (such as EVs) at the optimal time, which reduces demand peaks.

Advantages

Demand response can benefit the sustainability of the electricity sector by decreasing the generation required from fossil peakers. Effective demand response can also lower power prices by avoiding, or at least delaying, the cost of new generation and network expansion investment. As seen in our modelling, a pathway where demand response is much greater (i.e., *Pathway 2: Smart system evolution*) than otherwise (*Pathway 1: Business-as-usual*) reduces capacity in 2030 by 660 MW and saves $820 million in network investment in the 2020s. A smarter pathway requires 910 MW less capacity in 2050 and $8.7 billion less in network costs in the 2040s.

There are 2 ways to encourage demand response:

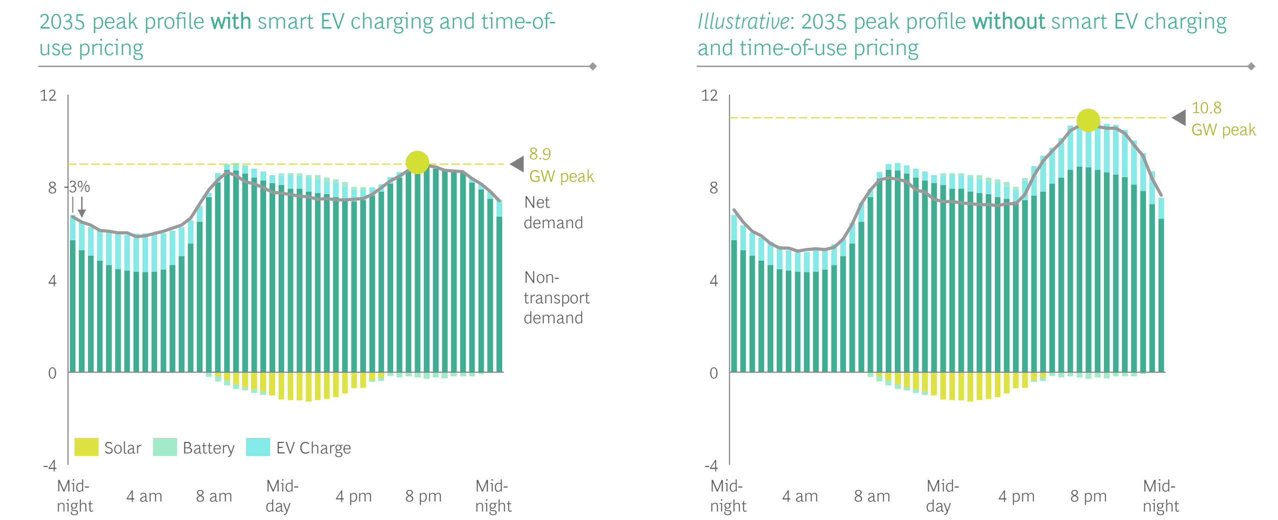
- Work with the largest industrial consumers of electricity (large-scale demand response). Tiwai Point, the largest single consumer of electricity in New Zealand, presents the greatest opportunity for demand response technology. Generally, the aluminium smelter requires a steady stream of electricity to keep the aluminium at a sufficiently high temperature. However, there is technology available that would allow the smelter to decrease its demand by up to 25%, without any adverse impacts on aluminium production.[69] In a submission to the CCC, it was estimated that demand response technology could cost $50–60 million to install and would come with economic upsides, such as energy arbitrage during dry years.[70] An agreement where the smelter provides increased dry year flexibility to Meridian Energy and other gentailers could provide greater certainty of dry year cover for the sector.

69 Newsroom, NZ firm promises solution to Tiwai Point, 2020
70 Interim Climate Change Commission, Energy Modulation of Tiwai Aluminium Smelter, 2019

- **Aggregate housing demand to encourage charging at a time of day that minimises capacity peaks** (small scale demand-response). The most logical time to charge EVs is at night when demand across the grid is lowest, and vehicles are less likely to be in use. Emerging technology could allow EVs to charge at the optimal time throughout the night when electricity is (expected to be) at its cheapest. The Electricity Networks Association (ENA) supports the mandating of all EV chargers being equipped with smart capabilities, stating such a move would "unlock significant potential for savings across the electricity supply industry by supporting flexibility services."[71] Domestic heat pumps also present an opportunity; trials have revealed that heat pumps with inbuilt energy management technology can maintain temperature profiles, while smoothing the demand curve, and reducing electricity demand overall.

A Transpower 2020 report estimated that in 2035, smart EV charging and 'time-of-use' pricing mechanisms can reduce peak energy demand from 10.8 GW down to 8.9 GW, with this 1.9 GW capacity difference representing more than twice the size of New Zealand's largest hydroelectric power station at Manapōuri and 60% greater than Huntly operating at peak capacity (see Exhibit 63). Further estimates are that, for every GW of peak demand saved, $1.5 billion in generation, transmission, and distribution investment costs can be avoided. As a result, EV smart charging could save the New Zealand economy close to $3 billion by 2035.[72]

Exhibit 63: **Smart charging and Time of Use pricing can reduce peak demand by 1.9 GW**

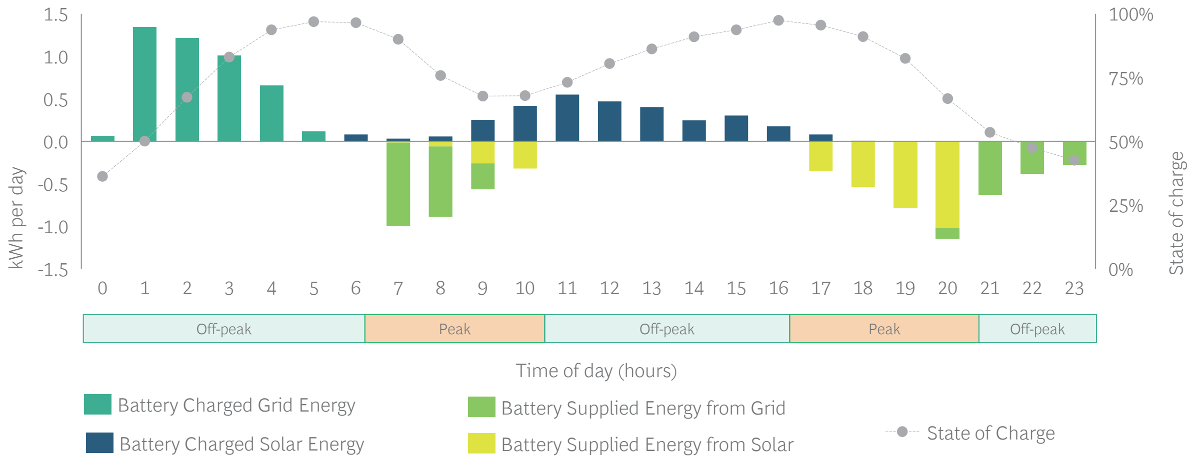


Source: Transpower

71 Energy News, ENA backs smart EV charger mandate, 2022
72 Transpower, Distributed Energy Resources and Flexibility Services, 2020

Batteries can also reduce peak demand by storing electricity when there is excess available and discharging when the system requires it. Exhibit 64 below outlines how a battery can be charged and supply energy over a typical summer day. As the direction of energy in and out of the battery fluctuates over the course of the day, the state of charge fluctuates. The state of charge can be optimised based on external factors (demand for electricity and availability of solar generation), as well as financial metrics (optimising financial return based on electricity prices).

Exhibit 64: **DER such as batteries can charge and discharge based on external energy flows**



Source: Sapere/Transpower Distributed Energy Resources (DER) Report

Distributed energy resources (DER) such as batteries and electric vehicles will have an increasingly important role to play in providing the electricity sector with additional flexibility and resilience through flexible supply-side and demand-side energy. DER also allows consumers to be more in control of managing their energy needs.

DER can provide savings over the life of the resource. A 2021 report by Sapere found that DER can provide multiple services to the electricity system.[73] The greatest ways in which value can be derived through DER are:

Resource adequacy for energy and networks
By increasing the amount of energy flexibility and effective capacity across the country, less investment in gas peakers, transmission, and distribution is required.

Energy arbitrage
Throughout the transition battery capacity will increase significantly. This offers opportunities to store energy when prices are low, and to sell electricity back to the grid or to customers when prices are higher. For the user, a profit can be made on a fixed kWh of energy, and more broadly, electricity price volatility can be reduced.

Simulated inertia
Inertia refers to the energy stored in rotating motors, which can prove invaluable when power stations fail, making up for the deficit in generation. Some generation and storage assets connected to distribution networks, instead of the transmission grid, can provide simulated inertia.

73 Transpower, Distributed Energy Resources (DER) Report, 2021

Disadvantages and challenges

A joint Australian and New Zealand government taskforce estimated that devices with demand response technology might cost $30 in certain applications. Although this would translate to a quick payback period, it is important to acknowledge this upfront cost, and provide consumers with clear rationale or incentive to install smart demand devices.

Smart demand response, in the form of vertical integration, could allow households or other types of electricity consumers to 'band together' to flex their demand. However, the administrative and technical overheads may offset the benefits – small-scale demand response is nascent and markets are only beginning to form. The capital costs of setting up this infrastructure may be prohibitively large for small-scale customers in certain settings.

Smart demand technology must be incredibly easy to use, with minimal thought required from the customer. iPhones, for example, employ 'optimised battery charging' to delay charging beyond 80% until just before the time the phone is typically required, to optimise battery health. If the customer was required to do this manually, it would be a laborious process; similarly, customers are unlikely to have the headspace to plug in their EV at the optimal half hour. Smart demand appliances must alleviate the need for the customer to think about when to charge. The systems and processes to allow this are still in early stages of development but are critical to the success of smart demand technology and reducing peak demand for electricity.

While the technological infrastructure to enable smart demand response is relatively mature and developing every year, there are potential headwinds. The systems, processes, and communications required to link assets to the grid require significant technology upgrades.

Sapere identified several challenges implicit in developing DER. It stated integrating DER and distribution networks with grid supply resources will be as profound a change, both technically and economically, as New Zealand's transition to an electricity market in 1996.[74] The right market conditions and incentives must be in place to build DER where they are most valuable to the individual consumer, as well as wider electricity sector. Building DER in the wrong place could be hugely problematic, particularly if built at too large a scale. Coordination across the sector is imperative.

Furthermore, while DER affords consumers more flexibility and more control over how and when they consume electricity, the dispersion of behind-the-meter resources can lead to increased complexity for the system operator. A whole-of-sector view is required to develop DER at scale, and because a range of technologies are encapsulated by the concept of DER, policy and regulations must be technology-agnostic.

Implications for the roadmap

A smarter, more flexible electricity sector will mean that significant amounts of additional capacity construction can be avoided — 660 MW by 2030, and 910 MW by 2050. This translates to network savings of $820 million in the 2020s and $8.7 billion in the 2040s. Demand response and distributed energy resources are beneficial to the entire sector.

74 Transpower, Distributed Energy Resources (DER) Report, 2021

3. Will just-in-time network investments continue to be sufficient in meeting increasing demand?

Just-in-time investment involves spending money on upgrades as and when it is required. This, the current approach to network investment, is somewhat deterministic, in that it relies on experience to inform future investment decisions, with minimal uncertainty.

Advantages

Today's approach to approving network investments supports making deterministic, just-in-time investment decisions. Demand growth has been relatively flat over the last 2 decades, with small incremental growth encouraging rather steady investments in transmission and distribution over time. This has corresponded to a steady increase in the development of power stations over time.

Waiting as late as possible before investing in the network has proven optimal for customers. Waiting to see where new generation is required to be connected to the grid, and where demand is greatest, has meant that consumers of electricity have not had to pay for unnecessary additional infrastructure. Given preferential outcomes for consumers, sector regulators (including the Commerce Commission) have traditionally preferred this approach to approving network investments.

Just-in-time investment comes with additional advantages. For one, it is simpler and more streamlined, in that there is less uncertainty and fewer assumptions in a deterministic model of required spend. It also reduces the requirement for early, upfront capital investment, and ultimately delivers necessary upgrades on time (assuming no prolonged supply chain delays, which are discussed below).

Disadvantages and challenges

While a just-in-time approach to network investment has served New Zealand well historically, conditions in the future will be different. Rapid renewable generation development and electrification means that there is uncertainty surrounding when and where new network infrastructure will need to be built. This uncertainty supports a probabilistic approach to investment, which requires an assessment of different possible scenarios and identification of those investments that satisfy the sector's needs across most or all credible pathways.

Given the uncertainty and fast pace of change, it is more likely that a just-in-time approach to investment could lead to investment that is too late; this could have significant consequences in a fast-changing environment, as system needs could quickly outpace infrastructure development if development is too slow. There is an asymmetry of risk between being too early and too late. If, for example, a given project to enable renewable generation is delivered 2 years ahead of need, customers will need to pay for the lost time value associated with the project, typically a small increment. If, however, a project is delivered 2 years too late, inhibiting new lower-cost generation, it could have a significant impact on wholesale prices for all consumers.

Investing in the network ahead of time will encourage renewable generation and electrification; with the infrastructure already in place, the business case for electrifying an asset is strengthened. Conversely, if transmission and distribution infrastructure is not built at sufficient pace, households and industries may be inhibited from connecting new renewable generation and embracing the electrification of transport, industrial processes, and buildings.

Transpower elucidated the disadvantages of the existing investment framework in its March 2021 submission to the CCC:

> When it comes to network investment decision-making, the next 15 years, and the 15 after that, are going to be very different from New Zealand's recent experience…our existing system has evolved to support least regrets investment decisions in a world that is evolving incrementally.[75]

Transpower proposes that, in the future, decisions will need to be made in advance, even in the face of imperfect information. Investing in network capability ahead of time creates options for further electrification and prioritises making decisions where inaction due to uncertainty is an unacceptable outcome.

Project development timelines for solar and wind are much shorter than historical timelines for development of traditional power stations. While thermal power stations take about 4 years to construct, renewable power stations take just over 2 years. With increasing prevalence of renewables globally, the average time to construct a power station decreased from 3.6 to 3.1 years between 2010 and 2018; notwithstanding supply chain delays, this

75 Transpower, Submission to the Climate Change Commission, 2021

decreasing construction time trend is likely to continue in the future.[76] As a result, approvals processes that have governed transmission investments to support these new developments, which have previously not presented a concern in terms of their timing, now risk holding up the construction of these renewables projects.

At the same time, complex approvals processes have increased, with more than half of the time spent from project initiation to commissioning being spent in pre-contracting activities. This has resulted in long development times for large projects, as seen in Exhibit 65 below.

Although waiting to invest may appear to be an efficient way to save money, investing in transmission too late stalls the development of low-cost renewable generation, and can therefore increase net prices and emissions. Investing too late in distribution can stall electrification (with economic consequences as a result), and hamper reliability. Analysis by Nexa Economics and Endgame Economics has identified that “a delay of even one year in delivering new transmission results in higher bills for consumers.” Wholesale costs in Australia have been modelled to increase by $30–80/MWh, depending on the state, which significantly outweigh the cost of delivering transmission one year early.[77]

The importance of forward planning and long lead times has been exacerbated by recent current supply chain headwinds, meaning that investing in transmission and distribution ahead of time is even more critical. In the future, the need for network investment to support decarbonisation is significant, but the timing of this investment is less certain. The above analyses suggest that the consequences of investing in networks too late significantly outweigh the additional costs of investing too early.

Exhibit 65: **HVDC and other major capital projects typically see long development times with pre-FID activities taking up over 50% of the project timeline**

Project	Description	Project initiated	Contracted date (proxy for FID)	Commissioned date	Time to FID	Time between FID/in-service	Total project duration
New Zealand HVDC Inter-Island Link Upgrade[1]	Proposal for upgrade of HVDC link between North and South Island *(note, project proceeded under a revised scope)*	2005	2008	2013	3y	5y	8y
WesternLink[2]	HVDC submarine link between Scotland and North Wales	<2010	2012	2018	>2y	6y	>8y
Nemo Link[3]	HVDC submarine cable between UK and Belgium	2006	2015	2019	9y	4y	13y
North Sea Link *(UK share of project)*[4]	HVDC submarine link between UK and Norway (under construction)	2009	2015	2021	6y	6y	12y
VikingLink[5]	Planned HVDC link between UK and Denmark	2014	2019	2023	5y	4y	9y

Source: 1. Transpower HVDC Inter-Island Link upgrade investment proposal (2005). Refers to expected pre-FID costs under original upgrade investment proposal (did not proceed with original scope), assumes linear project management and development spend profile across project duration; 2. Western HVDC project website; 3. Ofgem post-construction review of Nemo Link (September 2019); 4. Ofgem Final Project Assessment report, assumes linear project management and development spend profile across project duration, total includes contingencies, calculated based on UK share of cost; 5. VikingLink project website

76 International Energy Agency, Average power generation construction time (capacity weighted), 2010-18, 2019

77 Renew Economy, Even a one year delay in new transmission links will hurt homes and businesses, 2022

Implications for the roadmap

While just-in-time network investments have served New Zealand's electricity sector well to date, the decarbonisation imperative necessitates a different way of thinking. With increasing electrification and more intermittent renewable resources, probabilistic investment ahead-of-time investment is required. There are financial costs involved with not investing sufficiently ahead-of-time. Deterministic just-in-time transmission investment could hamper the construction of sufficient renewable generation, and delayed distribution expenditure could inhibit the electrification of transport, industry, and buildings.

4. Does Lake Onslow pumped hydro provide the best trilemma outcomes?

Lake Onslow is a proposed pumped hydro facility in Otago. The proposal could see Lake Onslow provide about 5 TWh of storage potential and a capacity of 800–1,200 MW. The idea of a pumped hydro facility at Lake Onslow was originally raised by Earl Bardsley of the University of Waikato in 2005 and gained traction when highlighted by the Interim Climate Change Committee's 2019 report.[78] The New Zealand Battery Project has been established by the Government to advise on the "technical, environmental and commercial feasibility of pumped hydro" and Lake Onslow has been identified as a possible frontrunner site.[79]

Advantages

As well as providing stored energy equivalent to more than 10% of New Zealand's annual electricity needs today, the single project would resolve much of New Zealand's dry year challenge. Unlike standard hydro projects that are exposed to hydrological conditions, pumped hydro can absorb excess or low-cost energy (for example, excess solar generation during the middle of the day) and store it in the form of a large, long-duration battery. This provides a high degree of flexibility, particularly in dry years, and pumped hydro at Lake Onslow would ensure 100% renewable electricity can be achieved in all hydrological conditions, possibly with the assistance of green peakers in the North Island to meet North Island peak demand.

Lake Onslow is also unique by global standards in terms of potential energy storage – by way of comparison, the 5 TWh storage would be 14 times the level of storage of Snowy 2.0 pumped hydro in Australia. As New Zealand has one-fifth the electricity demand of the Australian National Electricity Market (NEM), Lake Onslow would provide an impressive 70 times the level of energy storage of Snowy Hydro 2.0 on a pro-rated system basis for a similar or lower construction cost.

Pumped hydro at Lake Onslow would also decrease reliance on the gas market. The

78 Earl Bardsley, Note on the pumped storage potential of the Onslow-Manorburn depression, 2005

79 Ministry of Business, Innovation and Employment, NZ Battery Project, 2020

electricity sector would be less exposed to gas security concerns, to spikes in the gas price, and to the increasing carbon price. Lake Onslow would also reduce the level of renewable overbuild needed to meet dry years as it would be able to soak up excess renewable supply. Under our preferred pathway, the average level of renewable overbuild needed in 2030 is ~500 MW of wind and ~300 MW of solar to ensure optimal system outcomes. However, there is the possibility that renewable overbuild of this magnitude may not occur as it depresses the price received by these assets in the market. Lake Onslow would decrease the reliance on all market participants to overbuild renewable generation power stations to the extent required, including to meet the challenge of fulfilling New Zealand's electricity needs in dry years.

In a situation whereby pumped hydro at Lake Onslow costs $4 billion to construct, the cumulative system costs would be about $4.4 billion less than our central Lake Onslow scenario (where the modelled cost of construction at Lake Onslow is $6.2 billion, based on international benchmarking of similar projects). Approximately 200 kt CO_2-e more emissions would be abated each year, with electrification being aided by a $2/MWh decrease in the wholesale price of electricity.

Under *Pathway 4: Mega infrastructure build,* Lake Onslow also leads to decreases in average (mean) household energy bills of $20 in 2030 and $220 in 2050 below our business-as-usual pathway, which represents slightly less than what is achieved in the preferred pathway.

Lake Onslow could provide a broad range of system services across different time durations, including improving system stability in real time, providing significant peaking capacity to the grid, and offering dry year coverage. This means it could be an effective single point solution to several of the challenges facing Aotearoa New Zealand through the decarbonisation of the sector, and would be an all-round flexible resource.

Lake Onslow may also provide valuable firming for renewables and reduce day-to-day electricity prices by suppressing peak prices, reducing overall volatility. Notwithstanding the significant capital costs of construction, the increased availability of energy when it is needed would likely lead to a smoothing of the wholesale price over time. These price smoothing benefits, as well as the system services described in the previous paragraph, are conceptually illustrated in Exhibit 66 below.

In the event the levelised cost of energy for wind and solar remains higher than forecast (quite possibly due to supply chain constraints), large-

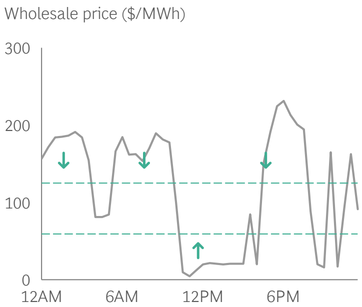
Exhibit 66: **Advantages of Lake Onslow include system and price stability**

System service capabilities

- 800 - 1200 MW peak capacity available (~15% of today's peak demand)
- Up to 5,000 GWh of energy storage available in dry years (14 times the size of Australia's Snowy Hydro 2.0 pumped hydro project)
- Frequency stabilisation support provided

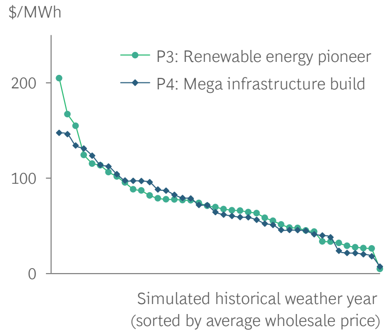
Pumped hydro at Lake Onslow provides a range of benefits to the New Zealand electricity sector

Daily wholesale price smoothing



A typical day's pricing profile shown in grey. Green arrows illustratively show stabilisation effect of large-scale pumped hydro

Inter-year wholesale price smoothing



Lake Onslow would ensure less variability in inter-year prices, with significantly lower prices than Pathway 3 in dry years

Source: Concept Consulting modelling, BCG analysis

scale lithium-ion batteries do not come down in cost as much as expected, gas prices increase, and the carbon price soars, building pumped hydro at Lake Onslow may represent a low-cost means of decarbonising New Zealand's grid. Similarly, if conditions arise where the cost of developing Lake Onslow are less than projected, this will improve the business case to proceed with the project, ensuring that the associated debt required to fund the project is less.

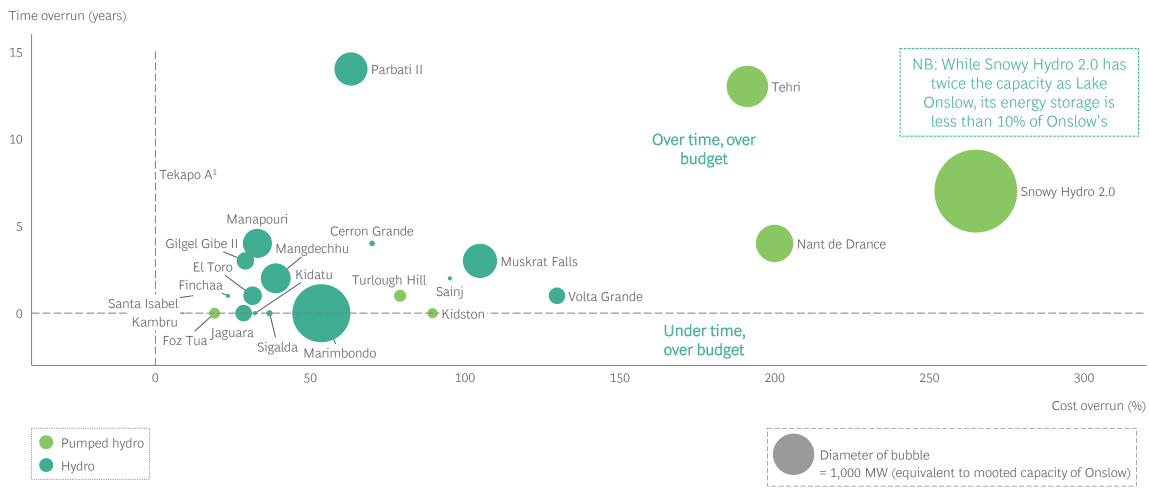
Disadvantages and challenges

Some projections indicate that building Lake Onslow could be expensive, compared with alternatives. The ICCC estimated that the project could cost $4 billion (equivalent to a marginal abatement cost of $250/tonne CO_2-e), take 4–5 years to build, and require 2 years to fill. The extent to which these costs would be passed on to consumers through power bills would depend on how project funding is ultimately recovered. As described below, there is the possibility that the time and cost to build could be higher.

Lake Onslow would be a major infrastructure undertaking. After access to land, water rights, and the power system has been established, resource consents would be required. The potential for flooding, with the associated loss of protected wetlands and peatlands, means that the cost of construction could increase to $6–7 billion.[80] Tunnels would then need to be constructed, which could be up to 20km long, if the lower pumphouse is located near the confluence of the Teviot and Clutha Rivers.

Globally, most pumped hydro projects have been built late and over-budget. For example, Snowy Hydro 2.0 in Australia, which is still under development, is now scheduled to cost 2.5 times as much as originally planned and take 7 years longer to build.[81] Benchmarking below shows 6 analogous pumped hydro projects built globally, across 5 countries, with the average project costing roughly over double as much as originally thought and taking 2–3 years longer to build. Benchmarking for hydroelectric projects globally reveals a similar picture. 17 projects across 12 different countries were benchmarked, based on initial and actual cost and time estimates, with the average hydroelectric project costing ~50% more than first thought, and taking almost 3 years longer to build. Both pumped hydro (in dark blue) and hydro projects (in a lighter green) are captured in Exhibit 67 below.

Exhibit 67: Cost and time benchmarking of pumped hydro and hydro projects



1. Initial cost estimate not publicly available

Note: Kidston, Tehri, and Snowy Hydro 2.0 are still under construction.

Source: International Bank for Reconstruction and Development (now The World Bank); Desktop research (including Web Cache), Press search, BCG analysis

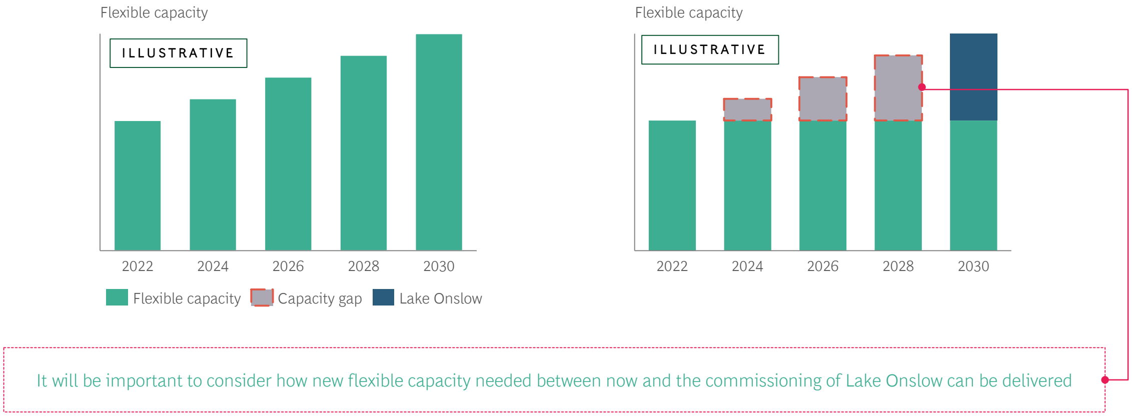
80 Dougal McQueen, Assessing Pump Hydro Energy Storage opportunities in New Zealand, 2019

81 Energy News, Snowy 2.0 costs surge, 2022

In a situation whereby pumped hydro at Lake Onslow costs $10.6 billion to construct, in line with Snowy Hydro 2.0's cost overrun in percentage terms (relative to a $6.2 billion construction cost, as modelled), the incremental cumulative system costs would amount to $11.3 billion. Approximately 500 kt CO_2-e fewer emissions would be abated each year, with electrification being stifled by a $5/MWh increase in the wholesale price of electricity.

Once fully commissioned, Lake Onslow will be an effective flexible resource for the electricity system. However, the transition through to full commissioning needs to be carefully considered. The electricity sector requires increased peak capacity and dry year energy this decade (see Exhibit 68). Lake Onslow's development, or even speculation that the project may go ahead, could impact investment in both interim and future flexible capacity.

Exhibit 68: **Illustration of transition considerations leading to Lake Onslow commissioning**



Source: BCG analysis

Building Lake Onslow may require additional peaking facilities to be built in the North Island, to ensure that enough capacity is available if a large North Island power plant or one of the inter-island HVDC cables were to fail. Because the HVDC is often capacity constrained at peak times, this could reduce the value of Lake Onslow capacity for meeting North Island peaks. In order to increase this capacity, more transmission infrastructure upgrades would be required.

This greater flow of electricity northwards could also pose a security of supply risk on the South Island transmission network and at Haywards (where the HVDC cable connects to the North Island transmission line) in the event of a large earthquake along the Alpine Fault or on the Wellington Fault adjacent to the Haywards substation.

Implications for the roadmap

While our findings demonstrate that Lake Onslow has many benefits, and also some drawbacks, the Government has an $80 million study underway as part of the New Zealand Battery Project that will provide much improved information on the project. This will assist with providing greater details on the cost, timeline to build, generation capacity, lake storage, how Onslow will operate in the market, and other aspects like consenting. Pumped hydro at Lake Onslow does not appear in our current preferred pathway – we acknowledge that this is built on several important underlying assumptions (e.g., Lake Onslow construction cost) that have degrees of uncertainty, for which improved information is likely to emerge over the coming months. Given the large uncertainties over the key parameters of Lake Onslow, it is too early for us to develop a strong view on its viability before the $80 million study is complete.

5. Will a 100% renewable electricity target lead to the best trilemma outcomes?

In 2017, the incoming New Zealand Government made the commitment that 100% of New Zealand's electricity will be generated by renewable sources by 2035 under normal hydrological conditions. In 2020, the governing Labour Party committed to bringing forward the target by 5 years to 2030, with a review in 2025.[82] The Labour Party also removed the 'under normal hydrological conditions' caveat although it is unclear if some thermal generation (for example, to provide peaking capacity in exceptional hydrological conditions) might be acceptable. This target was accompanied by a commitment to ban new thermal baseload generation, promote clean energy development, remove the barriers to developing new renewable electricity projects, advance green hydrogen and other green technologies, and support businesses to decarbonise.

Advantages

New Zealand is on track to reach 91% renewable electricity by 2025 and more than 98% by 2030 (including co-generation) with the current pipeline of consented generation development projects. A 100% renewable electricity target would further reduce New Zealand's energy generation emissions, however this depends on intricacies of the target – for example, whether fossil fuel peaking plant (peakers) could be used to firm electricity capacity in extenuating circumstances (e.g., particularly dry years).

A second advantage of a 100% renewable electricity target is that it removes ambiguity around what constitutes a 'tolerable' level of fossil fuel generation and reliance on market forces to drive decarbonisation. Even if the carbon price were to plummet, the phasing out of fossil fuels for electricity generation would proceed. In other words, such a target, if enforced, ensures that progress is made year-on-year to reduce emissions from the electricity sector.

Additionally, a 100% renewable electricity base means it would be easier to market and commoditise New Zealand's electricity. It could attract businesses from all over the world to set up in New Zealand. Data centres, hydrogen producers, and industrial manufacturers may be able to command a premium from their renewable electricity credentials.

Disadvantages and challenges

Further decarbonising the grid from 98% to 100% renewable electricity by 2030 would avoid only ~32 kt CO_2-e of annual emissions across the economy. While an additional 234 kt CO_2-e of emissions would be abated annually through renewable electricity generation, higher wholesale electricity prices under a 100% renewable pathway would inhibit electrification, results in 202 kt CO_2-e less abatement annually in other sectors of the economy. The abatement cost to reduce emissions from electricity generation by 234 kt CO_2-e, excluding rest of economy emissions, is $340 per tonne CO_2-e abated. This would also translate to an additional average cost, particularly in the North Island, compared

82 Labour Party, 100% renewable electricity generation by 2030, 2020

with if a 98% renewable path was pursued. Higher electricity prices have the added disadvantage of inhibiting electrification, particularly in more price-sensitive sectors such as medium-weight transport, and industrial processes.

Although New Zealand is building more renewable electricity assets each year, reaching 100% requires an overbuild of capacity that might see excess generation being spilled. Although some of the spilled energy might be stored in the future, it is likely that a 100% target would encourage additional overbuild of renewable generation. Due consideration needs to be given to the most cost-optimal way to meet New Zealand's electricity needs during dry years and periods when the wind is not blowing, and the sun is not shining.

It is likely that gas will play a role in at least the early stages of the decarbonisation transition. With an emissions intensity of ~500 kt CO_2-e per TWh of electricity generated, gas is a preferable source of electricity to coal (which has an emissions intensity of ~1,000 kt CO_2-e per TWh). When burned in an OCGT plant, gas can also ramp up quickly to meet peak demand. Without gas, there is a risk of electricity supply shortages while further renewable generation is built. A 100% renewables target means that it may be uneconomic for gas supply chains to remain available only in extenuating circumstances like dry years. The role of green gas is contingent on existing generation plants remaining available for transition to green gas.

Implications for the roadmap

A hard 100% renewable electricity target is not needed and could be detrimental. The additional system costs relative to the emissions abated implies a high marginal abatement cost – hence it would be better to focus efforts and spend on increasing electrification, rather than solely aiming for 100% renewable electricity (see Question 1). If current conditions persist, the country should reach more than 98% renewable electricity by 2030, and hence a level of renewable penetration very close to 100% may well be achievable.

6. What role will thermal power stations play in the future electricity sector?

Thermal power stations, such as Huntly, currently provide electricity to meet both peaking and baseload needs. As described in Section 4.3, 7% of New Zealand's electricity was provided by gas in 2021 and 6% by coal.

Advantages

The ability of thermal power stations to meet peak demand and dry year energy is well known. With the ability to operate in all weather conditions, coal and gas can be more reliable than intermittent sources. At present, there are no low-cost renewable fuel sources available in all weather conditions.

Thermal power stations also have the advantage of incumbency. The fuel reserves, supply chains, and generation infrastructure already exists today. Moreover, gas in New Zealand is domestically produced, and therefore provides New Zealand with a relatively reliable and secure source of energy. Historically, thermal power stations have been relatively cheap to run (especially in previous decades where the LCOE of wind and solar was higher) and provided reliability and security to the sector.

The emissions intensity of the electricity sector is currently about 120 tonnes CO_2-e per GWh. In 2030, the emissions intensity is forecast to be 23 tonnes of CO_2-e per GWh – a reduction of over 80% below today's levels. Under our modelling, by 2050 the emissions intensity is forecast to be 17 tonnes of CO_2-e per GWh – a reduction of 86% below today. These remaining emissions are fugitive geothermal emissions, and potentially a small amount of gas used in peakers.

As it stands, New Zealand's thermal power stations (including Huntly) provide needed peaking and dry year cover. Retaining just a small level of thermal generation in the system (2% of demand in 2030) through the transition closer to 100% renewable electricity will ensure more affordable and reliable electricity supply, with whole of economy emissions reductions comparable to a system with no thermals due to increased electrification.

At a glance: The gas transition

Gas has a critical role to play throughout New Zealand's energy transition. While this report focuses on gas in the context of electricity generation, it is important to also consider the broader gas market, as supply and demand dynamics have implications for the availability of gas for the electricity sector and energy markets. Less than a third of New Zealand's gas is used for electricity generation.

Gas can enable Aotearoa New Zealand to decrease its reliance on coal, particularly in dry years, thereby reducing emissions and decreasing reliance on international fuel sources. However, today when the electricity sector needs to use more gas in a dry year, supply often becomes constrained and the price of both electricity and gas increase. This has implications for all electricity and gas users.

For gas to successfully replace coal as part of the dry year solution in a way that meets energy system trilemma needs, security of gas supply would need to improve and the impact that dry years have on gas prices would need to be muted. This could be achieved through either increased gas storage and/or increased gas demand response.

Gas storage will be important in the future, to enable gas to be available as and when it is needed to meet peak demand and dry year energy gaps. Unlike coal, which can be stored for a period of months, gas once extracted must be used in a much shorter time span. The facility at Ahuroa, owned by First Gas and capable of storing up to 18 PJ of gas, is New Zealand's only meaningful storage facility. Genesis Energy, in their submission to the Gas Industry Company, have acknowledged the importance of gas storage, stating "Energy storage is key to decarbonisation…Genesis considers that a commercial case can be made for investing in fuel storage to support a more flexible operating model for thermal generation…modelling suggests a requirement for access to around 20 PJ of gas storage, with capacity to inject/withdraw 55 TJ per day."[83]

In dry years, other users of gas are implored to decrease consumption so that gas can be used to produce electricity. A formalised arrangement for gas demand response would improve this situation by providing increased certainty to gas users (who provide demand response) and to the electricity sector around securing gas at a predictable price and volume under a predefined set of conditions.

Methanex is New Zealand's largest consumer of gas, consuming about 80 PJ of New Zealand's gas each year (40% of 190 PJ total). It produces methanol, used in a multitude of everyday products including adhesive, foams, solvents, and paint, and has an important role to play in the energy transition.[84]

Methanex's Motunui plant is an important part of its global portfolio, accounting for about a quarter of its annual global production. Methanex would have to be appropriately compensated for providing this gas flexibility. With increased flexibility comes increased security and affordability, and therefore it is appropriate that this flexibility is priced accordingly. The best outcome for the energy system overall is for Methanex to be able to flex its production, decreasing the amount of gas consumed over an intra-month period, and to receive sufficient payment (potentially through an 'option' style agreement) for providing this flexibility to the electricity sector.

The Gas Industry Company (GIC) has identified that "alongside gas storage, planned demand response by Methanex is likely to be readily available and at large enough volumes to enable the flexibility in the system needed to provide the security of supply required." The GIC has proposed a workstream is developed to understand Methanex's future role in the gas market. A key focus of this "will be on the appropriate commercial arrangements to underpin any planned demand response, how these are enabled and who ultimately pays."[85]

83 Genesis, Submission on Gas Market Settings Investigation, 2021

84 Methanex, How methanol is used, 2016

85 Gas industry Co., Gas Market Settings Investigation: Report to the Minister of Energy & Resources, 2021

In the future, OCGT facilities could run on biomethane or biodiesel. The capital costs of conversion will be relatively small, as most of the required thermal stations have already been built. These can ramp up and down quickly, at the desired capacity, to meet short-term peaks, and these facilities' locations in the North Island mean that they are well placed to serve increasing peak demand from the North Island. Biofuel blending (such as biomethane/natural gas blends) could be used throughout this transition to green fuels, with the unit costs of the fuel potentially decreasing over time. While the short-run marginal cost of biomethane and biodiesel will exceed that of fossil gas or diesel for decades, the increasing carbon price and a declining gas sector by 2040 will significantly narrow the difference in costs between biofuels and their fossil alternatives. Given 98% renewable electricity should be achieved by 2030 onwards, the amount of required thermal generation is sufficiently small that biomethane or biodiesel could be used to achieve 100% renewable electricity around 2040 without significant additional system costs incurred.

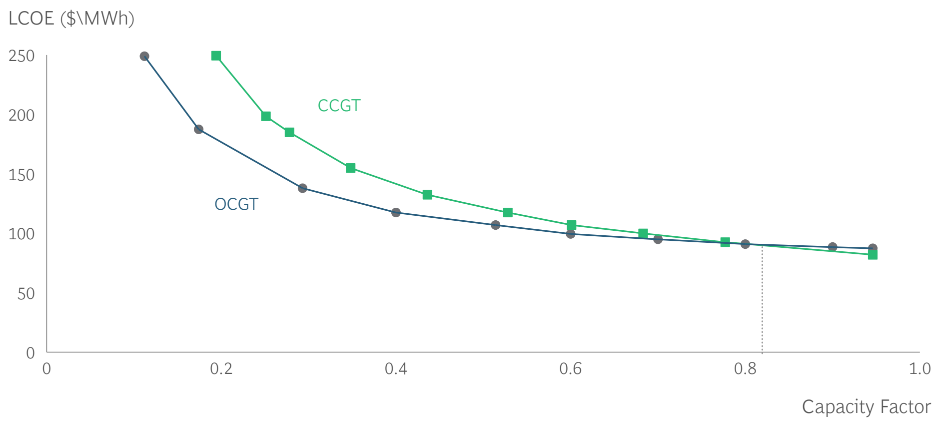
Disadvantages and challenges

The obvious disadvantage of thermal power stations is their associated emissions, with coal and gas accounting for 82% of New Zealand's annual electricity sector emissions, or 1.6 Mt CO_2-e and 2.3 Mt CO_2-e respectively. This disadvantage will decrease rapidly over the 2020s as the country reaches 98%+ renewable electricity in 2030 across all modelled pathways.

With more intermittent renewables in the energy mix, slow-start thermal plant (such as those powered by coal) will be less suited to meeting peak demand. This means that, under all pathways, coal is forecast to not be required for electricity generation by 2030. Peak capacity will be required at short notice within a day to meet unforeseen cloudy and still periods. The utilisation of slow start thermals will decrease, making it harder to derive economic returns, not just because renewables will be lower in the bid stack and dispatched first, but also because these plants will not be able to generate electricity fast enough to meet short-term demand peaks.

In general, combined cycle gas turbines (CCGT) have higher capital costs and lower operating costs than open cycle gas turbines (OCGT), as well as being slower starting. This indicates that CCGT units need to have a high capacity factor in order to be more economically viable than OCGT. Exhibit 69 depicts the LCOE of OCGT and CCGT plant respectively, acknowledging that LCOE is not a perfect comparator given that such plant have already been constructed in New Zealand. As capacity factors decrease and thermal power stations are called on less regularly, this is highly unlikely to be the case. As a result, OCGT will become preferable to CCGT through the transition.

Exhibit 69: **Comparative cost of OCGT v CCGT depends on utilisation/capacity factor**

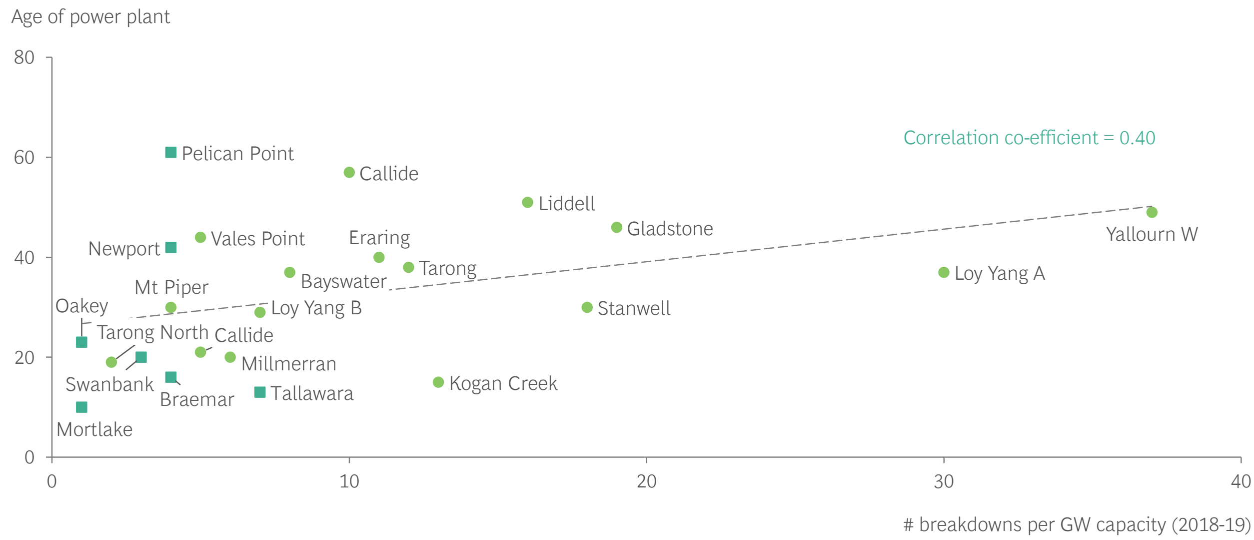


Source: US Energy Information Administration

Furthermore, the existing thermal stations are aging. For example, the Rankine units at Huntly Power Station were commissioned between 1982 and 1985.[86] Reliability tends to decrease as thermal power stations age. Analysis of 23 power stations in Australia shows that, as power stations get older, the number of breakdowns (per GW) increases, with a correlation co-efficient of 0.40 (see Exhibit 70).

Building thermal power stations is not only capital-intensive, but these plants are also likely to be used less as more renewables are built. This means a longer payback period, which makes it harder to justify the investment. Compared with a 34% utilisation rate today, thermal generation utilisation has been modelled to be 8% by 2030. There are further significant risks involved with building, connecting, and

Exhibit 70: **Moderate positive correlation between age of facility and number of outages**



Source: The Australian Institute (Breakdown per GW data); BCG analysis

maintaining a thermal generation plant. Even if consent is granted, assets may be scrutinised, both politically and environmentally; public sentiment will only swing further towards favouring renewable over thermal generation assets as the energy transition progresses.

Finally, as reticulated gas is replaced by other fuel sources (see Question 7), overall gas demand will drop, and it may be harder to maintain a minimum viable amount of flexible gas supply. Gas policy settings may change, which, when combined with investment uncertainty, make investing in gas-fired generation a risky proposition.

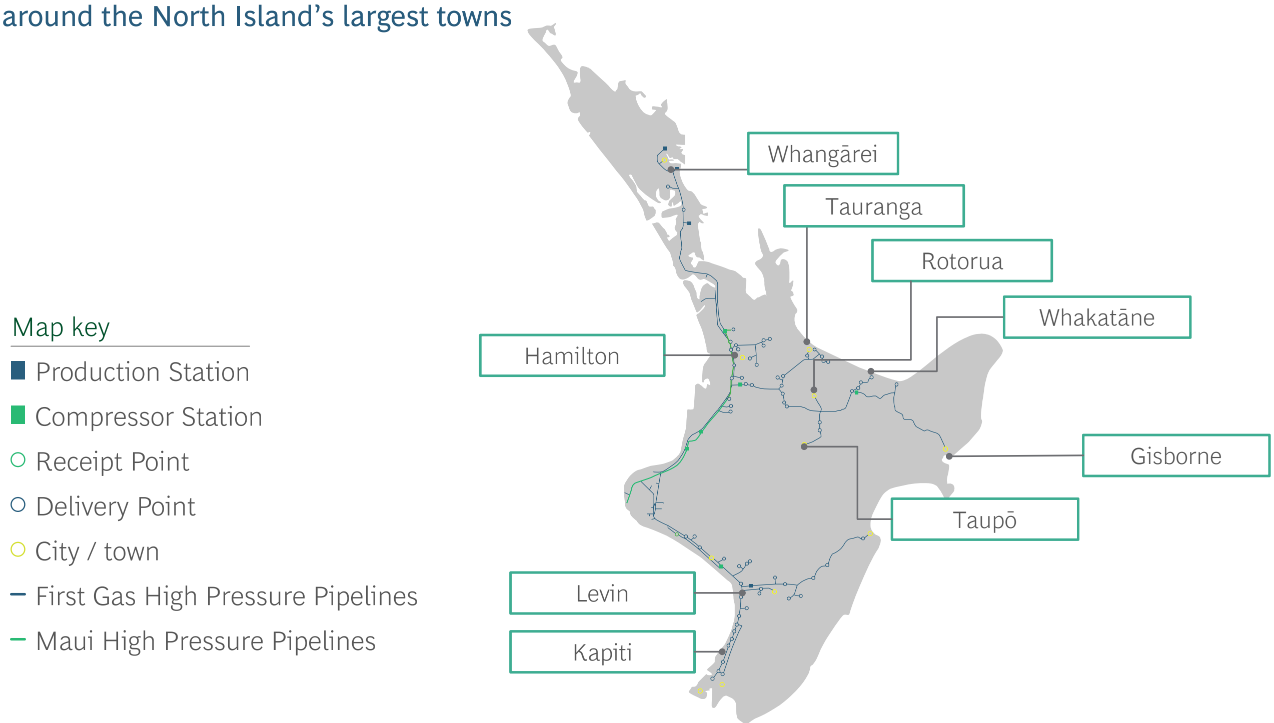
Implications for the roadmap

Thermal power stations will have a small but important role in the future electricity sector. Fast-start thermal plant will help to meet peaking and dry year challenges, through their ability to respond quickly and provide flexible generation. Through time, biofuels may serve as a viable alternative to natural gas, although under a mandatory 100% renewable electricity target, switching to these biofuels too soon, when the cost is high, may be uneconomic and undesirable in terms of overall emissions reductions.

7. What role will electrification and hydrogen play in displacing reticulated natural gas?

One intricacy of the reticulated gas network in New Zealand is that it only exists in the North Island. Gas is piped from the Taranaki south to Wellington and Hawke's Bay, and north to Northland, Auckland, the Waikato, Bay of Plenty, and Gisborne (see Exhibit 71). The network is made up of more than 4,800 km of pipes connecting gas production stations in the Taranaki to more than 260,000 customers via gas retailers, and 2,500 km of high-pressure gas pipelines supplying industrial consumers.[87] Liquefied petroleum gas (LPG) is used in the South Island, in lieu of reticulated gas. As a result, the largest industrial users of gas (including wood/pulp/paper, chemical and dairy manufacturing) are in the North Island.

Exhibit 71: **New Zealand's reticulated gas network transmission line is centred around the North Island's largest towns**



Source: First Gas

As New Zealand transitions to net zero, reticulated fossil-fuel gas (natural gas piped through the network across New Zealand) will need to be progressively replaced. The 2 most likely candidates to replace reticulated gas are electricity (where feasible) and hydrogen.

87 FirstGas, Network Map, 2020

Electricity: Advantages, disadvantages, and challenges

As discussed throughout this report, electricity represents a relatively clean, available, low-emissions source of energy. Low temperature heat processes (i.e., lower than 100°C) such as space and water heating represent an exemplar opportunity for electricity to displace reticulated gas, as it is cheaper than alternatives. To date, New Zealand has already seen many gas-fired boiler systems replaced with electric boilers.

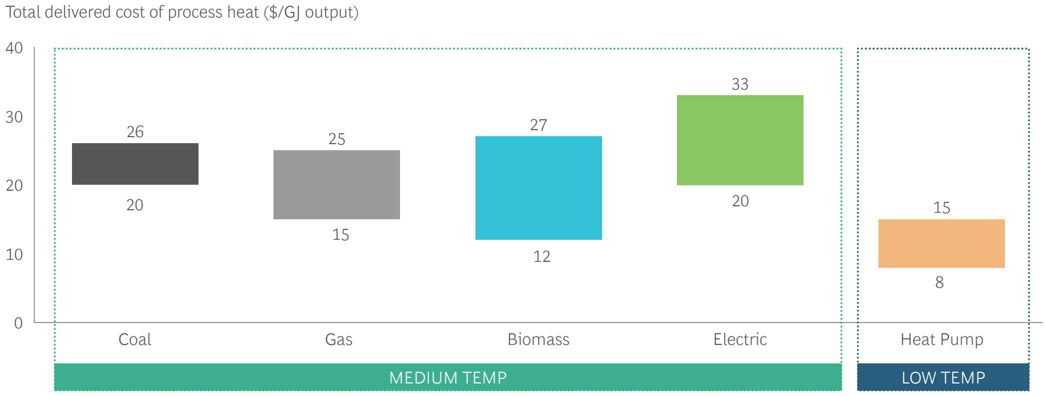
Exhibit 72 below shows how a heat pump makes economic sense for low temperature processes, and that for medium temperature heat (between 100 and 300°C), the unit economics of electric boilers relative to other fuels are comparable. Renewable electricity costs are likely to decline over the coming decade, while the increasing carbon price will raise the price of coal and gas, and demand for wood chips used to produce biomass will also increase. This means that electric solutions for medium temperature process heat will become increasingly desirable.

New Zealand's Ministry for Business, Innovation and Employment (MBIE) and Castalia, in their joint *New Zealand Hydrogen Scenarios* report, note that "electric kilns may also be possible for high-temperature process heat as technology develops. However, this would entail high capital costs to replace existing equipment and would require a large amount of electricity."[88]

In comparison to hydrogen however, direct use of electricity is more efficient. In New Zealand, a country with a high penetration of renewable electricity, using electricity to displace reticulated gas is preferable to imported hydrogen produced from less clean sources of electricity.

Finally, most of the necessary infrastructure to generate and distribute electricity exists today. Further upgrades to transmission and distribution networks are required to cope with increased uptake of electrification, but the starting point is strong.

Exhibit 72: Comparative total delivered cost ($/GJ) of process Heat with different fuel types



Source: Energy Efficiency & Conservation Authority (adapted); BCG analysis

88 Ministry of Business, Innovation and Employment, New Zealand Hydrogen Scenarios, 2022

Hydrogen: Advantages, disadvantages, and challenges

Because electricity may not be cost-effective for high temperature processes, nor is the technology readily available, hydrogen is thought to represent a viable alternative in the future. Hydrogen blending, as well as pure hydrogen, can both reduce emissions from reticulated gas. Hydrogen has use cases beyond replacing reticulated gas (such as heavy transport, and as a feedstock in fertiliser and steel manufacturing), which means that economies of scale for obtaining hydrogen should be attained, regardless of whether it is produced in New Zealand or imported.

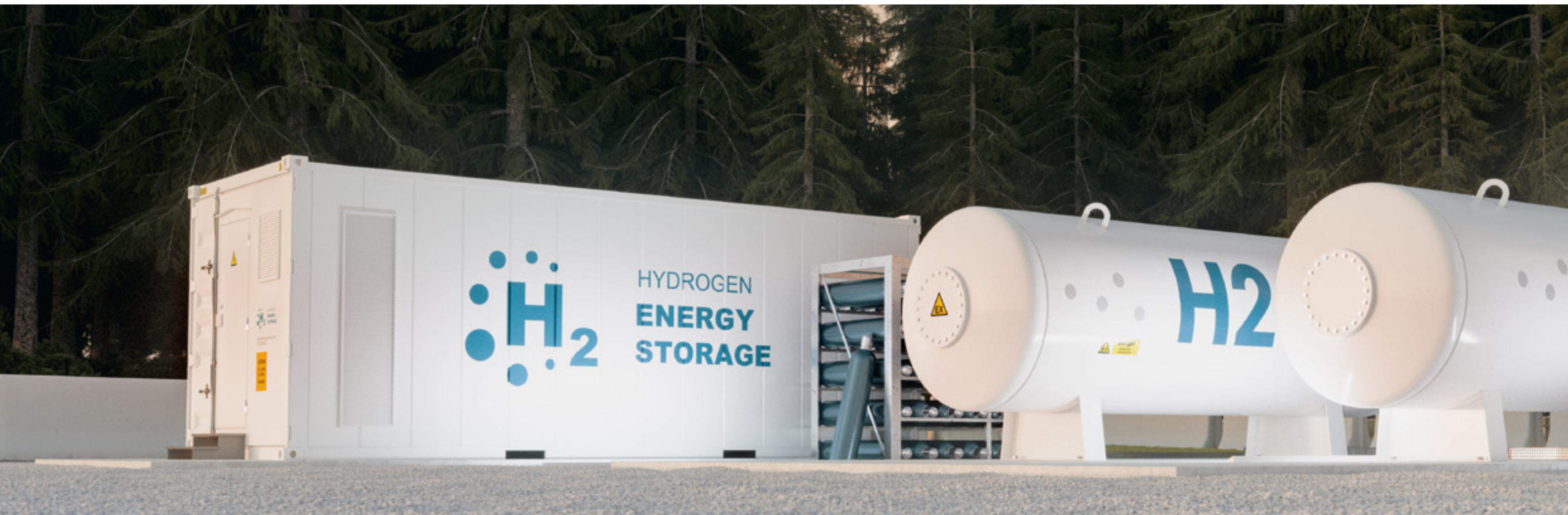
The costs of producing hydrogen are also forecast to decrease over time. New Zealand could competitively produce hydrogen, but only if trade route diversification into Japan and South Korea and supply chain costs are managed appropriately. In a mature, liquid market, the LCOE of solar generated hydrogen out of Australia will likely be lower, and New Zealand will lack a competitive advantage.

Hydrogen also has the advantage of being able to use existing gas infrastructure, including network pipelines, and storage and distribution facilities. Reusing this infrastructure avoids bearing sunk costs as well as decommissioning costs. If total energy consumption from hydrogen matches gas demand today, then using existing gas pipelines for transmission and distribution of hydrogen may be cheaper than upgrading the electricity network in the North Island. In the South Island, however, where there is no reticulated gas network, building such infrastructure may prove costly. Progressive blending of hydrogen or other green gases like biogas may also enable businesses reliant on a form of reticulated gas energy to remain in business through the transition and enable a smoother transition for households reliant on gas.

The additional benefit of hydrogen, as discussed in relation to Question 5, is the demand response potential during dry years and demand peaks. The advantages would be two-fold: hydrogen production could smooth demand for the electricity sector and displace gas for higher temperature process heat. This assumes that a production facility would be built in Aotearoa New Zealand, and that it would be of sufficiently large scale that its demand response would be meaningful at a national level.

Implications for the roadmap

Electricity (and to a lesser extent, biomass) will likely ramp up as reticulated gas ramps down. For low and medium-temperature processes, electrification makes economic sense. Most of the generation, transmission, and distribution infrastructure already exists, to be complemented by new renewables and network connections. Hydrogen could serve as a viable alternative to reticulated gas in the North Island but is more expensive and less efficient than electrification in general. For this reason, electrification is given greater credence in the roadmap.



8. What are the implications of a hydrogen export facility for the future electricity sector?

Hydrogen is likely to have an important role in future energy systems, both in New Zealand and around the world. Hydrogen's future use cases span heavy transport, high temperature process heat, and industrial feedstocks (for example, in fertiliser and steel manufacturing). Hydrogen can unlock benefits for New Zealand as an export, given a large-scale facility should be able to produce more hydrogen than the nation requires.

Advantages

A hydrogen export industry brings 2 major benefits for New Zealand. The first is economic: if hydrogen is shown to be economically valuable to produce in New Zealand, then the country's strong renewable electricity base can serve as a competitive advantage for producing hydrogen at scale for export. The second relates to demand response: a hydrogen production facility could provide demand flexibility over a period of days, weeks, and months.

Southern Green Hydrogen is a joint project currently being undertaken between Contact Energy and Meridian Energy, to evaluate the prospects of producing green hydrogen (and adjacent products, such as ammonia) in Southland. With a feasibility study completed and potential developers shortlisted, it represents the most logical choice of location for a facility that could produce hydrogen at scale, due to its proximity to hydroelectric dams and its cooler temperatures. It has been envisaged that such a facility could help resolve part of New Zealand's dry year issue by providing large-scale demand flexibility, and that a facility would not lead to a meaningful increase in peak electricity capacity above today's levels.[89] Analysis by Contact Energy, Meridian Energy, and Concept Consulting shows that the value of a hydrogen production facility, where 70% of production ramps down when prices are high on an hourly basis, and 30% of production only turns on when prices are very low, could reduce wholesale electricity sector costs by $50 million annually.[90] Economically, it has been estimated that the facility could add $350–450 million GDP per year to the New Zealand economy, as well as between 4,000 and 6,000 jobs, assuming 853 MW of electrolyser capacity.

Hydrogen for domestic consumption may also form part of the future local energy mix, for example, in heavy transport and as an industrial feedstock. An export facility may make hydrogen more accessible for domestic consumption. The sector could leverage and share expertise and standards to guide the transport, handling and use of hydrogen.

Disadvantages and challenges

Building a large hydrogen export facility may be contingent on the future of the Tiwai Point smelter. Without a step-change in the amount of renewable generation and capacity built across the country, it is unlikely that the aluminium smelter and a hydrogen export facility could co-exist, while ensuring electricity supply security. The sharp increase in demand for electricity from a hydrogen export facility could lead to capacity scarcity in the years following its commissioning (particularly if Tiwai Point stays).

89 Provided the facility replaces the aluminium smelter at Tiwai Point

90 Concept Consulting, Potential benefits from large-scale flexible hydrogen production in New Zealand, 2021

The direction of international hydrogen markets is uncertain, as is New Zealand's role in these markets. This makes the viability of an export facility highly uncertain. It is widely accepted that for most use cases Australia, Chile, and Saudi Arabia will be able to produce hydrogen on a bigger scale and at less cost than New Zealand. However, in the case of Southern Green Hydrogen, with the flexibility it can provide, New Zealand may be able to compete with these countries. Furthermore, if countries such as Japan, South Korea, and Singapore seek a diversified range of markets to arrange hydrogen contracts, this may support the case for an export facility in New Zealand. Shipment costs, electricity costs, and the use rate of the facility are all variables that will determine the economic viability of such a facility.[91]

The extent to which a hydrogen export facility can provide flexibility is highly contingent on contract arrangements. In an immature, illiquid hydrogen market, with hydrogen supply largely controlled by bilateral contracts (as expected for at least the next decade), variability in the supply of export hydrogen may cause difficulties for flexible contracts which may not be desirable to some customers.

Implications for the roadmap

A hydrogen production facility could provide large-scale demand response and provide a source of GDP and jobs to New Zealand. However, the price of electricity, and therefore the price of hydrogen produced, would have to be sufficiently low to compete with other nations, such as Australia. Therefore, for a large-scale hydrogen production facility to be economically viable, hydrogen would need to be produced at comparable prices, or New Zealand would need a unique competitive advantage in providing green hydrogen to certain markets.

9. To what extent should the electricity sector retain optionality, at least until 2030?

The electricity market is a complex system, and it is difficult to address the interconnectedness of the sector when we have so far considered each of these questions independently. Moreover, different combinations of options will lead to different outcomes; it may be that 2 separate options appear undesirable in isolation, but in combination lead to optimal trilemma outcomes for New Zealand. This section considers the value of optionality, and the trade-offs between a single point solution, as opposed to an evolutionary, multi-faceted approach.

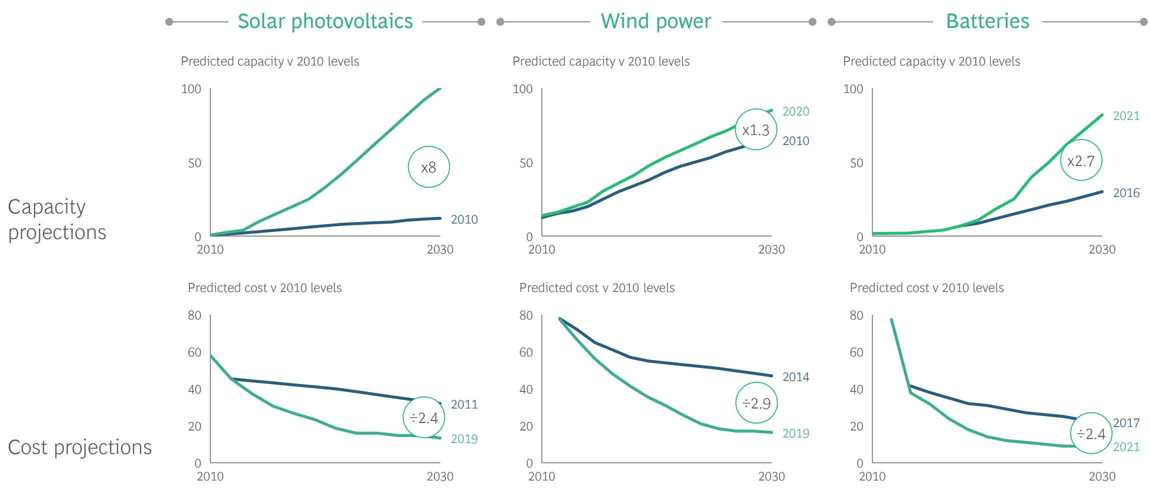
Advantages

As our modelling shows, no one pathway is optimal under all possible future states. Therefore, it is likely going to be preferable for New Zealand's electricity sector and governments to keep options open. Large, single-point investments remove optionality; option value is important when making decisions with imperfect information. Having several technologies available to meet the various challenges facing the New Zealand electricity sector (peaking, dry year, and network challenges) means that, if a particular set of circumstances play out, then a suite of options are available to respond. A single asset approach removes this optionality.

91 Ministry of Business, Innovation and Employment, New Zealand Hydrogen Scenarios, 2022

In addition, the Interim Climate Change Committee reflected in relation to its dry year analysis: "The analysis costed each individual option as separately solving the dry year problem. But, depending on the solution, what may be more cost effective, and environmentally and socially acceptable, is to deploy a range of smaller options to provide a coordinated response across different technologies."[92] Hence, a range of solutions to tackle each of the challenge areas will likely be a more effective, reliable, and equitable approach.

Exhibit 73: **Uptake in renewables to be driven by rapidly increasing capacity and sharply decreasing cost of relevant technologies**



Source: International Energy Agency; International Renewable Energy Agency; BCG analysis

Preserving optionality means that the market can be more adaptive to emerging technologies over time. We would also learn more about the capacity cost of these technologies; Exhibit 73 above shows that historically, we tend to underestimate the capacity, and overestimate the cost of renewable technologies such as solar photovoltaics, wind power, and batteries. Maintaining optionality means better assessing how the costs of other technologies, such as pumped hydro schemes, flow batteries, hydrogen, and green gas may evolve, which will inform their feasibility in New Zealand.

Gas peakers are one example where maintaining optionality may prove useful. Peakers can be used on a select number of days per year to meet exceptional demand. With gas not being used for any baseload, the percentage of electricity generated by renewable sources could be driven above 98%. This may be advantageous, as gas peakers come with low capital costs, flexibility, and a good location in the North Island—and these facilities could be converted to green gas in the future.

It is quite likely that a holistic solution, incorporating smart demand, storage, DER, peakers, and a large increase in the capacity of intermittent renewable energy sources may be required. Our modelling in Section 6 confirms this.

92 Interim Climate Change Committee, Accelerated electrification, 2019

Disadvantages and challenges

Preserving optionality means neither over-investing in a vast number of solutions to cover all possible eventualities, nor waiting to invest indefinitely. There is a real risk that preserving optionality across all time horizons can lead to inaction, with a lack of commitments made; there comes a point at which assets need to be built despite imperfect information. In the words of 14th century German theologian Meister Eckhart: "The price of inaction is far greater than the cost of making a mistake".

Single point investments bring associated economies of scale. A single project is exposed to fewer externalities and brings a smaller number of variables into the sphere of control of the asset. It is also more conducive to action from government to drive desirable outcomes (such as a very high proportion of renewable electricity), while supporting the necessary policy, market, and regulatory reform, as this change can be concentrated around a smaller number of initiatives.

Implications for the roadmap

Relying on a single solution represents a concentration of risk but can lead to positive outcomes if it assists with delivering action and overcoming uncertainty. However, in our modelling, a range of renewable generation, storage, demand response, and other technologies are leveraged to enable more than 98% renewable electricity by 2030.

7 Decarbonisation roadmap

Now that we have identified 4 key energy system challenges to overcome, selected a preferred pathway, and evaluated the 9 questions critical to the future electricity sector, in this section we:

- Share our recommended roadmap for delivering the preferred *Pathway 2: Smart system evolution*.
- Discuss the importance of this roadmap's whole-of-sector perspective and why this perspective should continue as the sector implements the roadmap.
- Look at the roadmap in the context of our 4 energy system challenges, outline what needs to be done to address them, and assess whether the work already underway is sufficient to achieve this.

7.1 A roadmap for the 2020s, 2030s, and 2040s

To implement *Pathway 2: Smart system evolution* – a desirable, lower cost pathway, with optimal outcomes for the grid and consumers overall – planning needs to start today. This requires a concerted, aligned effort from the electricity sector, consumers and government. Our recommended roadmap to deliver the pathway is shown in Exhibit 74. It highlights the need for about 5 GW of additional renewable generation capacity, supplemented with approximately 1 GW of supply-side and 2 GW of demand-side flexibility to be developed each decade. At least $8 billion and $22 billion will need to be invested in transmission and distribution respectively each decade. These long-term investments will drive overall energy sector emissions reductions of 8.7 Mt CO_2-e annually in 2030, and 22.2 Mt CO_2-e in the year 2050.

Exhibit 74: Electricity sector delivery roadmap to enable decarbonisation in the 2020s, 2030s, and 2040s

		2021–2030	2031–2040	2041–2050
	Summary	• Rapidly build renewable generation to reach 98% renewable electricity; phase out coal • Ramp up electrification supported by targeted thermal gen., demand flexibility and storage	• Turbocharge electrification through a continued fast build out of renewable electricity • Develop new flexible renewables, storage options and a highly automated demand-side	• Continue electrification at pace to support close to full decarbonisation of key sectors • Significantly scale up batteries and further embrace new smart demand technologies
Renewable generation	**Additional capacity**	~4,800 MW	~5,300 MW	~5,000 MW in 2040s
Renewable generation	**Additional generation**	~10.6 TWh	~10.8 TWh	~12.8 TWh
Renewable generation	**% renewable electricity**	98%	99%	99% (Option to achieve 100% at low cost)
Peak demand	**Additional peak demand needs**	1.1 GW supply-side flexibility (peakers, storage) 2.0 GW demand-side flexibility (EVs, demand response)	0.8 GW supply-side flexibility (peakers, storage) 1.7 GW demand-side flexibility (EVs, demand response)	1.2 GW supply-side flexibility (peakers, storage) 2.1 GW demand-side flexibility (EVs, demand response)
Dry years	**End-of-decade dry year energy contribution**	7.6 TWh (including 4.7 TWh renewable overbuild, 1.7 TWh OCGT and 1.2 TWh demand response)	8.7 TWh (including 5.4 TWh renewable overbuild, 2.0 TWh OCGT and 1.3 TWh demand response)	9.4 TWh (including 6.4 TWh renewable overbuild, 1.9 TWh OCGT and 1.1 TWh demand response)
Physical Networks	**Transmission**	Invest $8 bn in projects such as: • Deliver NZ Grid Pathways Phase 1: Central North Island, Wairakei Ring, HVDC upgrade • Build Renewable Energy Zones (REZs), if needed	Invest $10 bn in projects such as: • Complete NZ Grid Pathways Phase 1 projects • Implement NZ Grid Pathways Phase 2: Develop grid backbone for regional growth / REZs	Invest $11 bn in projects such as: • Continue to deliver NZ Grid Pathways Phase 2 projects – grid backbone and REZ projects to enable a resilient power system
Physical Networks	**Distribution**	Invest $22 bn in initiatives such as: • Scale up physical network for electrification • Invest in smart systems to enable virtual infrastructure and DER orchestration	Invest $25 bn in initiatives such as: • Continue investment during rapid electrification • Invest in smart systems to enable real-time management of complex multi-directional flows	Invest $24 bn in initiatives such as: • Continue investment to enable electrification • Enhance smart systems to enable real-time optimisation of complex multi-directional flows
	Electrification enablers	• Rapidly electrify light vehicle fleet • 1.0 million EVs by 2030 • Commence large-scale transition of low/med temp. heat to electrification and biomass	• Phase out new ICE light vehicles; transition heavy vehicles to electric/ hydrogen • 2.4 million EVs by 2040 • Transition low and medium temp. processes	• Electrify almost all land transport • 4.3 million EVs by 2050 • Scale up elec./hydrogen for high temp. processes; phase out fossil fuels in buildings
	Energy sector emissions reductions	8.7 Mt CO_2-e	15.6 Mt CO_2-e	22.2 Mt CO_2-e

Source: Concept modelling, BCG analysis

7.2 The importance of applying a whole-of-sector perspective to this roadmap

Decarbonising New Zealand's energy system is complex. It requires public and private actors across the sector to work constructively to reach the best outcome for New Zealand.

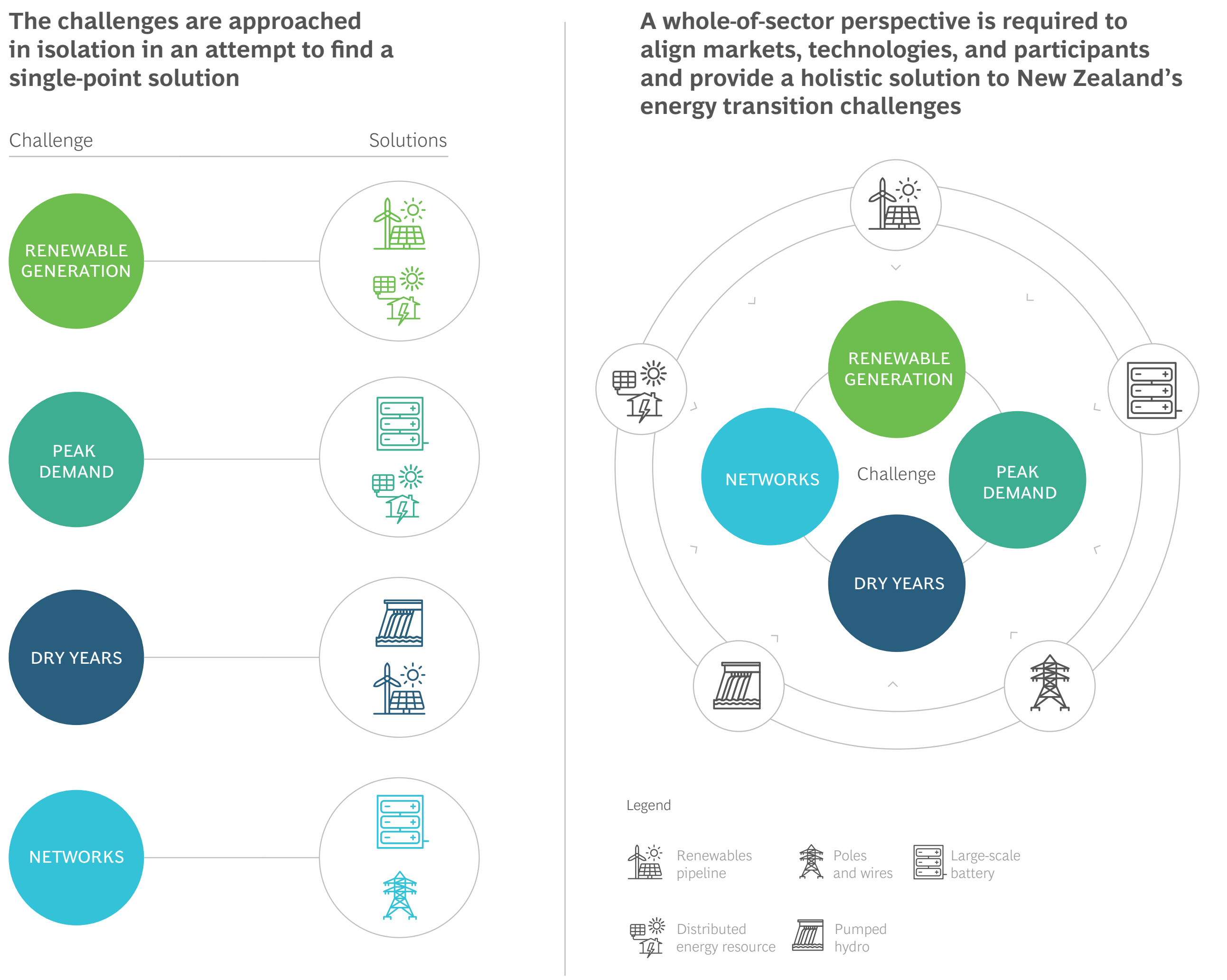
When developing this roadmap, we took a whole-of-sector perspective, looking at the vast amount of activity occurring to increase renewable electricity and electrification. The roadmap considers the work underway and further requirements to realise this preferred pathway for New Zealand.

The whole-of-sector perspective is also valuable in assessing how broader initiatives fit together to deliver the right outcomes for the energy system (see Exhibit 75).[93] For example, considering dry year solutions in isolation may not lead to the best solutions for meeting North Island peaking capacity. An integrated perspective is critical to achieving the best whole-of-sector outcomes.

From here, the sector needs to apply this whole-of-sector perspective to implementing this roadmap. The sector must drive the direction and momentum of the energy transition, and address its main challenges, in an integrated way. With a clear view on the optimal pathway, the sector can align markets and incentives and reduce barriers for participants to deliver the best outcomes for consumers and the energy transition.

We have identified shortfalls in the preferred pathway and associated recommendations in Section 8 to ensure the roadmap can be delivered.

Exhibit 75: The need for a whole-of-sector perspective



93 Vector, *Whole Electricity System Costs*, 2021

7.3 Addressing our 4 energy system challenges

The roadmap outlines what needs to be delivered to overcome the 4 energy system challenges:

- **Renewable generation:** Develop new renewable generation at a sufficient pace
- **Peak demand:** Ensure sufficient flexible generation and demand capacity to meet increasing peak demand
- **Dry years:** Ensure sufficient flexible generation and demand energy for dry years
- **Networks:** Develop sufficient distribution and transmission infrastructure (including smart virtual infrastructure) to enable new electrification, connect new generation sources, and provide flexible capacity

To develop a realistic roadmap that addresses all 4 challenges, we analysed data provided by 14 organisations across the sector to understand the work underway. This information was triangulated against additional aggregated and anonymised project data provided by Transpower.

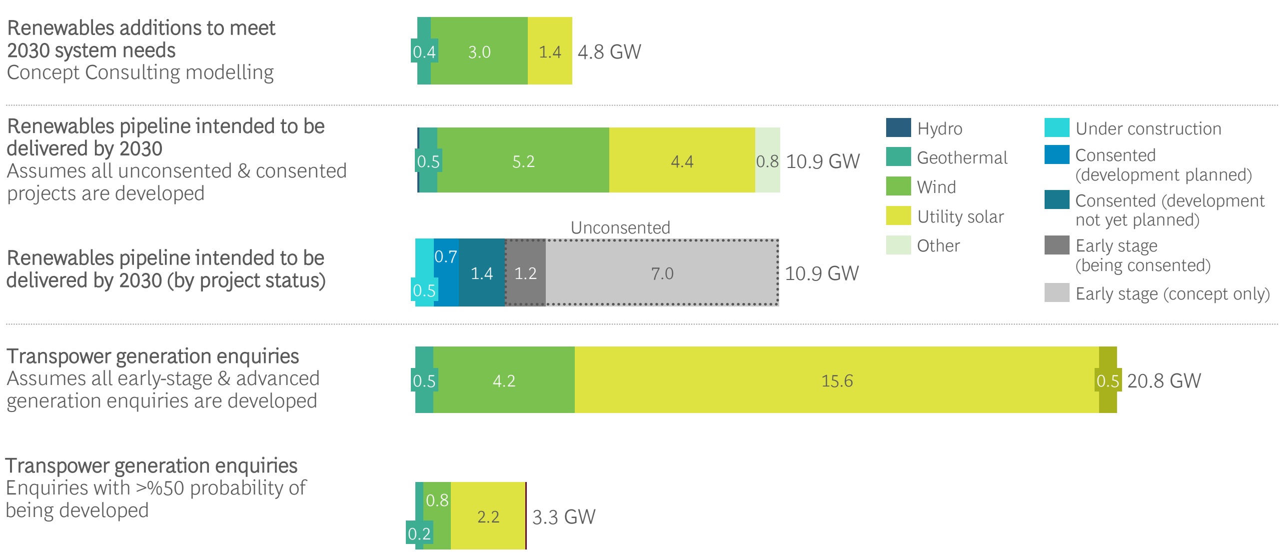
The sector has made a strong start on a pipeline of renewable generation projects, with many under construction or consented. The sector is also prioritising security and reliability of electricity supply by investigating energy storage systems, flexible generation, and flexible demand response for aluminium smelters, data centres, and green hydrogen projects. Investment in the transmission and distribution network continues to be a priority.

Challenge 1: Develop new renewable generation at a sufficient pace

To facilitate the whole-of-sector roadmap, significant renewable generation will be required to meet new electrification demand and increase the percentage of renewables to near 100% (up from 82% today).

By 2030, ~4.8 GW of new utility-scale renewable capacity will need to be constructed. Substantial progress on this expansion has already been made. The organisations who contributed information for our analysis outlined their intentions to develop 10.9 GW of new renewables by 2030, which would exceed the total capacity required (see Exhibit 76). However, it is likely that there will be a gap between stated intentions and what is developed at an aggregate level.

Exhibit 76: **Utility-scale renewables pipeline to 2030**



Note: Capacity does not include battery storage systems or DER/small-scale generation types; Pipeline projects categorised as 'Wind' include both onshore and offshore wind; Transpower generation enquiries pipeline excludes commissioned and in-delivery projects as well as 'prospect' connections (no formal enquiry) and 'unlikely' connections (<5% probability of development); 'Other' includes other renewable technology types such as hydro, bio energy and waste to energy; Where it was unclear whether a project had received consent, the project's capacity was assumed to be planned with no consent; Transpower generation enquiries may be developed after 2030; Renewables pipeline data correct to 30/09/2022.

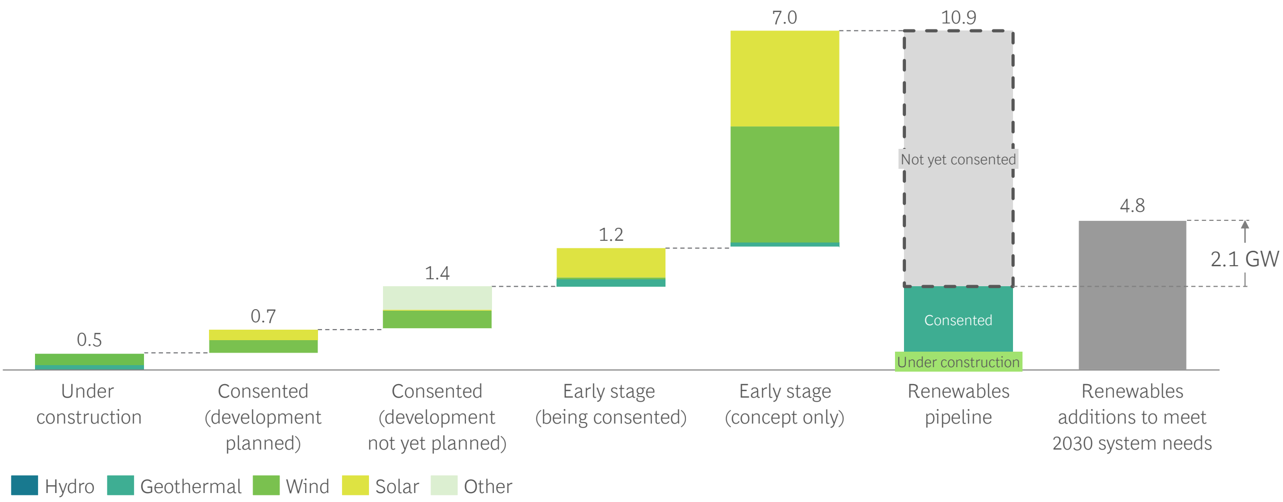
Source: Concept Consulting modelling, BCG analysis; Transpower

When further breaking down the pipeline, there are:

- 550 MW under construction (will be developed)
- 2,150 MW consented, for development this decade (highly likely to be developed)
- 8,200 MW in the early stage category

In total capacity terms, this leaves a 2.1 GW gap of generation required to achieve the 4.8 GW of new, large-scale renewable generation by 2030. This would need to be addressed by about a quarter of the 8.2 GW of unconsented projects that organisations have indicated they intend to develop, which mostly consists of wind and solar (see Exhibit 77). These projects need to progress very quickly if they are to be fully developed by the end of the 2020s.

Exhibit 77: **Renewables pipeline intended to be delivered by 2030 (by project status and technology type)**



Note: Capacity does not include battery storage systems or DER/small-scale generation types; Pipeline projects categorised as 'Wind' include both onshore and offshore wind; 'Other' includes other renewable technology types such as hydro, bio energy, and waste to energy; Where it was unclear whether a project had received consent, the project's capacity was assumed to be planned with no consent; Renewables pipeline data correct to 30/09/2022.

Source: Transpower; BCG Analysis

While this analysis captures the scale of the task at an aggregate capacity level, not every MW is of equal value to New Zealand's electricity sector. The potential for the renewables pipeline to deliver affordable, reliable, and sustainable electricity is impacted by the technology mix, geographic placement, and supporting network infrastructure of the various proposed projects. After accounting for the technology mix of projects in the pipeline that have already been consented, a further 0.3 GW of geothermal, 1.6 GW of wind, and 1.0 GW of utility-scale solar capacity needs to be approved and developed to meet 2030 system needs.

The sum of these capacity requirements exceeds the 2.1 GW total renewables capacity gap because the current project pipeline includes other renewable generation types not included as a part of Concept Consulting's 2030 model, reiterating the diversity in options that exist for the electricity sector to support New Zealand's decarbonisation. For example, if proven to be commercially viable in the context of New Zealand's energy system, NZ Super Fund and Copenhagen Infrastructure Partners' 1 GW offshore wind proposal could contribute some of the wind capacity that will be required in 2030.[94]

94 The extent of the area of interest could also allow a second GW of offshore wind to be constructed

There is also a further ~10 GW of enquiries that Transpower has received that were not provided to us by the organisations that contributed towards our analysis. The capacity of these enquiries may include projects from organisations that we:

- Have engaged during this process, where the organisation has **not** outlined their intention to build the project by 2030
- Have **not** engaged with during this process, where the organisation intends to build the project by 2030
- Have **not** engaged with during this process, where the organisation does not intend to build the project by 2030

The 20.8 GW of renewable generation enquiries received by Transpower, which sit in parallel to our pipeline analysis, include early-stage concepts that may never progress to seeking consent. Only 3.3 GW are expected, with over a 50% likelihood, to proceed to construction. It is also likely that several of the unconsented projects in Transpower's pipeline are competing for the same grid connections, meaning not all of them will be developed.

Of note, only 2.2 GW of the 15.6 GW of utility-scale solar enquiries to Transpower are likely (>50% probability) to be developed. With utility-scale solar only just being recognised as an emerging energy solution in New Zealand's power system, the opportunity cost of converting flat, arable land into a solar farm creates uncertainty as to the portion of these projects that will progress to a final investment decision – commentary out of Europe suggests only one-third of grid-scale solar projects reach construction.[95]

However, based on the information we collected from organisations as part of our pipeline analysis, we assess that it is highly likely enough generation is intended to be developed by 2030 to meet the system needs of the preferred pathway. We also acknowledge that there are several limitations that could possibly inhibit these necessary developments, including:

- An overly restrictive consenting framework for generation and network infrastructure
- Potential transmission constraints this decade
- Connection regulations that make it difficult for large solar farms to connect to distribution networks
- Lack of a clear consenting and development pathway for offshore wind (although this is under development)
- Lack of a deep PPA market for independent generation

95 Transpower, *Whakamana I Te Mauri Hiko: Monitoring Report March 2022*, 2022

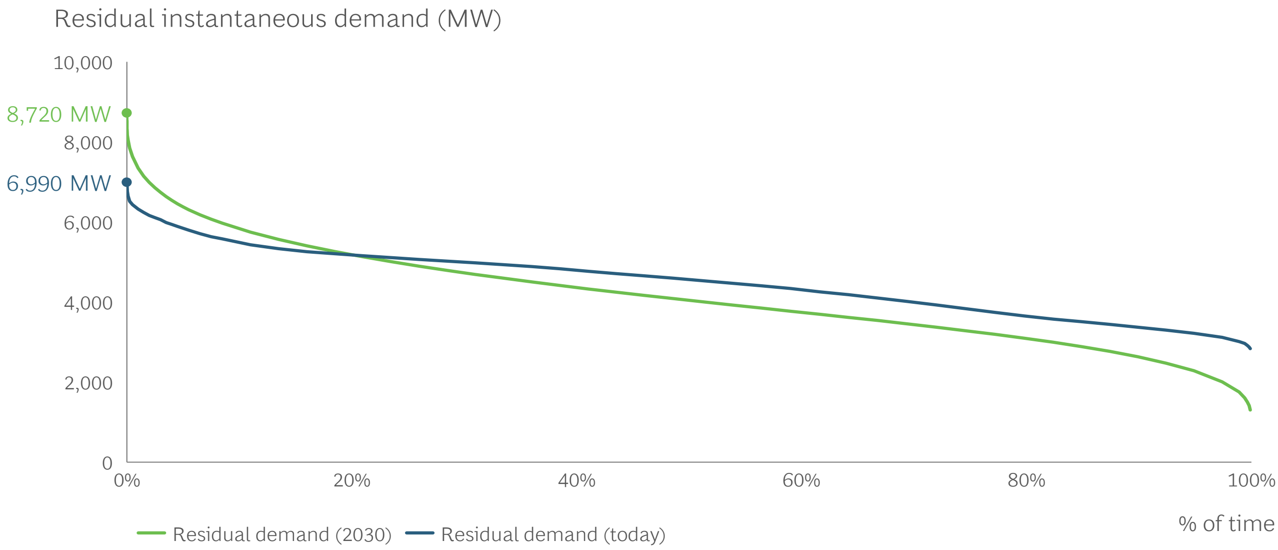
Challenge 2: Ensure sufficient flexible generation and demand capacity to meet increasing peak demand

In the modelling, peak demand in New Zealand's electricity system is expected to reach ~9 GW in 2030 and more than 13 GW by 2050, driven by growing load volumes and changing patterns in storage, supply, and demand. To meet future peak demand, substantial flexible supply-side and demand-side capacity will need to be installed, considering:

- Growth in demand peaks due to higher rates of electrification
- Higher levels of intermittent wind and solar, which create variability in generation and residual demand[96] and drive the need for fast-start capacity

As residual load profiles become more dynamic, fast-start flexible capacity will become increasingly important. To meet the steeper residual load profiles that are expected (see Exhibit 78), a variety of flexible resources will be required. On the supply side, these include utility-scale, dispatchable renewables such as pumped hydro and geothermal, flexible OCGT peakers, and large- and small-scale batteries.[97] Demand shifting and demand response (including from industrial processes, hot water systems, space heating, smart appliances, and thermal/cold stores) and smart EV charging will also become increasingly important to satisfy future peaks.

Exhibit 78: **2030 residual demand duration curve**



Note: Shows generation required to meet residual demand after wind and solar (i.e., accounts for DC losses)

Source: Concept Consulting modelling, BCG analysis

96 System load after behind-the-meter solar, utility-scale solar, and wind

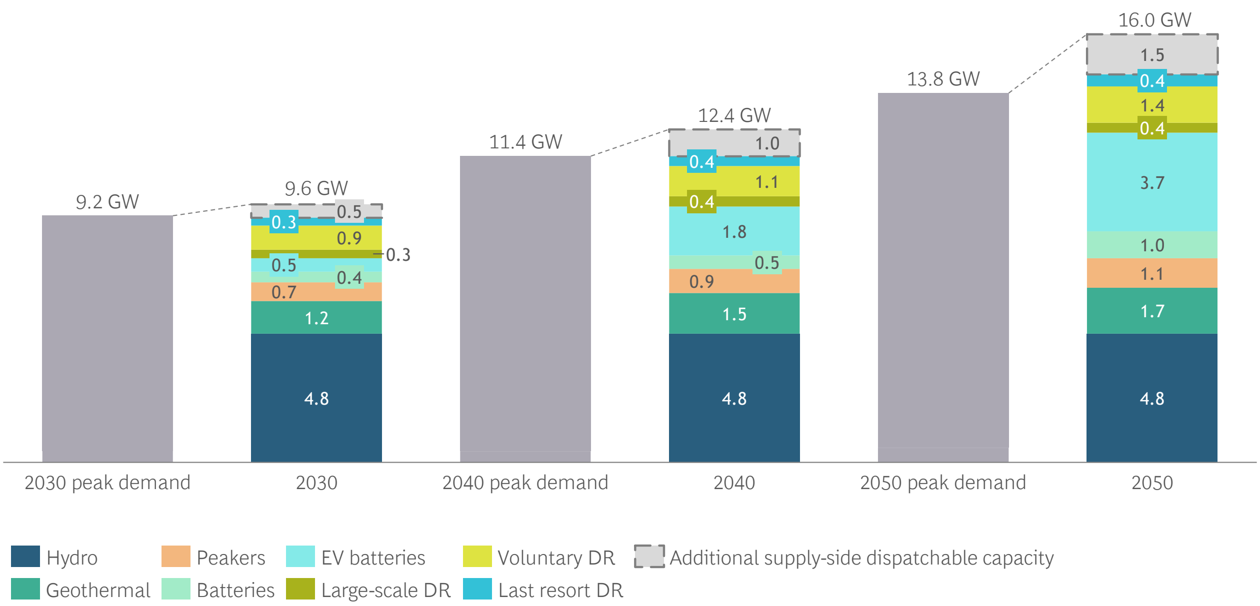
97 Though we categorise batteries as flexible supply-side resources, batteries can participate in both the demand and supply sides of the market

Flexible, supply-side resources

Modelling reveals that fast-start flexible, supply-side resources will play an important role in ensuring resource adequacy at peak periods in the future. It identifies that a total of 400 MW of battery storage and 700 MW of gas peaking capacity is needed to meet the highest 2030 demand peak (see Exhibit 79). However, this modelling output is determined by solving for the most economic outcome within the wholesale electricity market. It does not account for other revenue streams that may exist, including compensation for deferral of network investments or provision of ancillary services. Storage may also be paired with new renewable developments to relieve congestion in areas of the grid that are commonly constrained to limit the curtailment of renewable generation.

With the potential for batteries to access additional value streams under a smart system pathway, additional supply-side dispatchable capacity may be incentivised over and above what has been identified by our modelling. This value-stacking may see an incremental 0.5 GW, 1 GW, and 1.5 GW of flexible capacity realised in 2030, 2040, and 2050 respectively, where these volumes could reasonably evolve due to developments exogenous to the wholesale electricity market but also assist in meeting heightened peak system loads.

Exhibit 79: **Dispatchable capacity to meet highest demand peak**



Note: Demand includes the generation need to account for DC losses but does not include the contribution from wind and solar generation

Source: Concept Consulting modelling, BCG analysis

Of the capacity provided by peakers, intermittent supply and an increasing gradient of future peak demand will require any remaining or newly constructed OCGTs to be highly flexible in nature. The variability in the future system's residual load profile will see peaking plants ramp up for short periods to fill capacity gaps.[98] The median time thermal plants generate per start will decline by 83%, from 24 hours today to 4 hours in 2030, and the mean time thermal plants generate per start will decline by 97%, from 215 hours today to 6 hours in 2030.

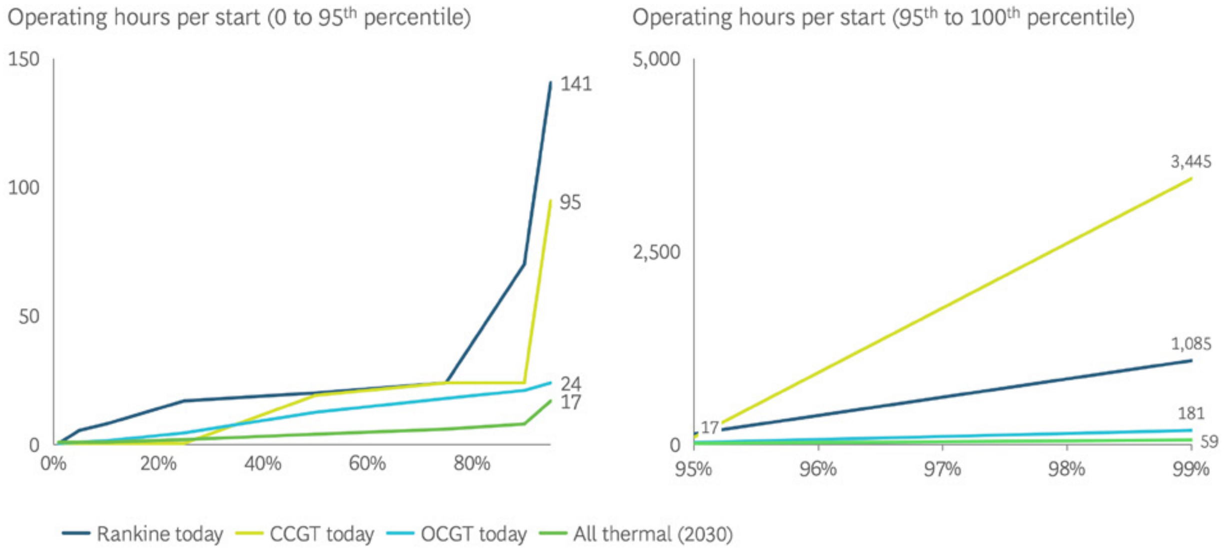
As we approach 2050, the median and maximum time of operation significantly declines from today's levels (although the mean run time does increase between 2040 and 2050, see table below). This reflects the need for thermal to not only ramp up for shorter, sharper periods to firm future renewable intermittency, but also to fill generation gaps that last from hours to weeks during extended periods of low wind and solar output in the renewable grid of the future.

Thermal plant operating times

	Median time of thermal operation per start	Mean time of thermal operation per start
2021 actuals	24 hrs	215 hrs
2030	4 hrs	6 hrs
2040	3 hrs	4 hrs
2050	2 hrs	7 hrs
Change in 2030 vs 2021	**-83%**	**-97%**

98 System load after behind-the-meter solar, utility-scale solar, and wind

Exhibit 80: **Thermal operating times today vs 2030**



Source: Concept Consulting modelling, BCG analysis

After accounting for likely capacity retirements, our modelling suggests that 200 MW of new, fast-start peakers will be required to meet the future needs of the system. As the plants providing this capacity will only need to generate for short durations in the near future, they are subject to a degree of revenue risk. Furthermore, the carbon risk associated with gas generation could make it difficult to support the business case for a new OCGT plant.

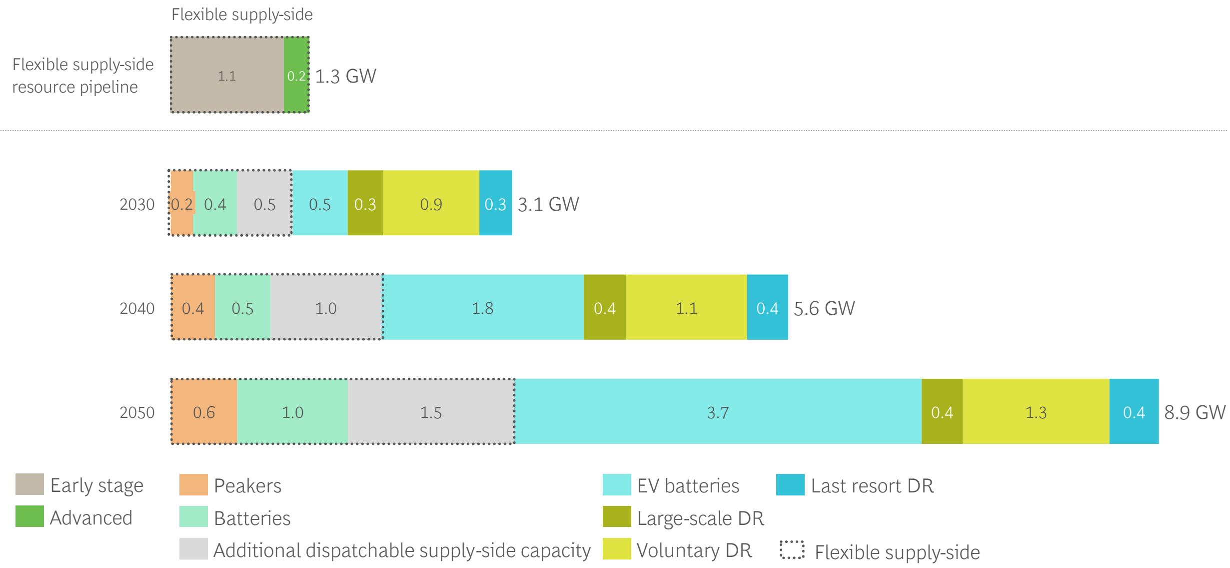
While our modelling identifies a specific mix of peaking capacity, we acknowledge that a similar peaking volume could be achieved with a different resource mix.

For example, the model predicts 200 MW of new OCGTs will need to be developed. In the situation where investment in new fast-start peakers does not occur, additional batteries could provide substitute fast-start capacity to meet peak demand. Another alternative could see Huntly Unit 5 (E3P) operated in a way that provides medium-start peaking capabilities. As such, an alternative market outcome that still satisfies the model's system needs might involve retaining Unit 5 at Huntly, with fast-start batteries filling the rest of the peaking capacity gap.

Considering the flexibility provided by peakers and batteries in aggregate, approximately 1.1 GW of incremental capacity will need to be installed to meet future peaking requirements on the supply-side of the system. The organisations who contributed to this analysis indicated a pipeline of 1.3 GW of flexible, supply-side resources (see Exhibit 81). The capacity in this pipeline is comprised of both utility-scale storage and OCGT peakers, with 200 MW in advanced stages of enquiry and likely to proceed to construction.[99]

99 Though we categorise the pipeline for peak demand as flexible supply-side resources, batteries can participate in both the demand and supply sides of the market.

Exhibit 81: **New flexible capacity to meet peak demand**



Note: 'Flexible supply-side resources' comprised of peakers and batteries; 'Early stage' pipeline projects include projects in initial enquiry stage, concept assessment stage, or have received consent but have no planned development; 'Advanced' pipeline projects include projects in investigation or delivery stage.

Source: Concept Consulting modelling, BCG analysis; Transpower

Analysing the existing pipeline of flexible supply-side resources, current intentions of participants may need to increase to meet peak demand by 2030. This is likely to occur as some early-stage projects are developed, and new projects emerge as the cost of storage rapidly declines.

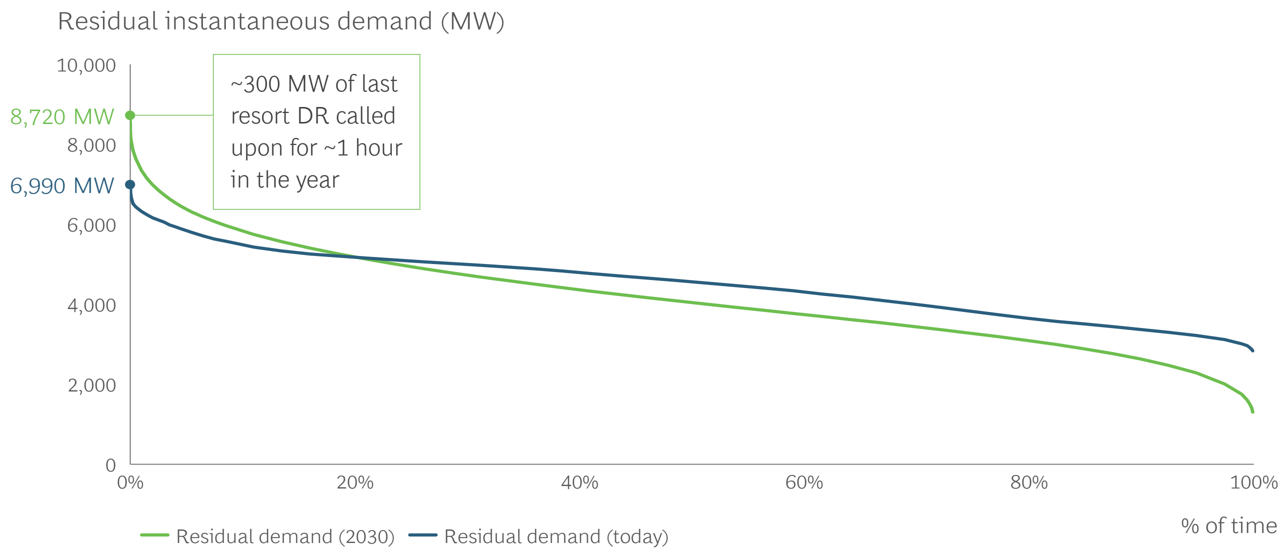
Smart, flexible demand-side and network resources

Flexible demand provides another means for meeting peak demand as it allows electricity consumption to be flexed in line with supply. The predominant technology types assumed by the model to flex household and small business demand include EVs, hot water systems, heat pumps, smart appliances, and thermal/cold stores.

Different tranches of voluntary demand response are implicitly priced according to energy consumers' willingness to shift their load from peak times to another part of the day. Concept Consulting modelling assumes that, at price ranges of \$700–\$3,000/MWh, up to 5% of demand will be willing to respond, while at higher prices of \$3,000–\$10,000/MWh, up to an additional 5% of demand could be flexed. As a last resort, a further 5% of demand could be flexed at prices greater than \$10,000/MWh.

The model treats the most expensive tranche of demand response (>$10,000/MWh) as involuntary in nature, requiring the system operator to shed load to balance supply and demand. Our modelling requires up to 300 MW of this capacity to be called upon in 2030, but only as a last resort for a total of ~1 hour over the course of the entire year (see Exhibit 82). Despite its short duration, this volume of involuntary demand shedding could still be perceived as an unacceptable degree of demand curtailment by consumers, potentially undermining their faith in the reliability and integrity of the New Zealand electricity system. As such, an economically affordable market construct that could avoid this 1 hour of load shedding may include a system of emergency reserves, which would allow the system operator to procure and call upon flexible capacity as a last resort at times of tight market conditions. This is discussed further in Section 8, Recommendation 2.

Exhibit 82: **2030 residiual demand duration curve**



The smart technologies that will be used to call upon discretionary volumes of demand response are still maturing. Several smart, demand-side initiatives are already underway that will help meet incremental peaking capacity. These include various large-scale industrial demand response programs, as well as initiatives led by electricity retailers in search of new revenue opportunities and solutions to manage the risks of their own energy peaks (see Appendix 2: Decarbonisation Commitments and Initiatives). Smart EV charging technology, platforms, and tariffs are increasing uptake of electric vehicles to reduce the load they demand from the system at times of peak demand – modelling revealed that by 2030, 50% of EV charging load may need to be deferred at times of peak demand. Such flexibility could reduce system load by up to 500 MW.

Flexible EV charging capacity

		2030	2040	2050
Pathway 1 **Business-as-usual**	# EVs	1.0 million	2.4 million	4.3 million
	Smart EV %	20%	50%	80%
	Smart EV peak availability (MW)	200 MW	1,200 MW	3,090 MW
Pathway 2 **Smart system evolution**	Smart EV %	50%	75%	100%[100]
	Smart EV peak availability (MW)	500 MW	1,830 MW	3,680 MW

Electricity distribution businesses can also call upon network flexibility to avert their own peaks. If these periods of load shifting coincide with peak demand at the system level, flexible network resources can help to balance the wholesale market and ensure resource adequacy at times of peak load. However, to fully unlock the flexibility that can be derived from networks, significant investment in smart technologies, as well as improved visibility at the lower voltage spectrum of the network value chain, will be required over the coming decades.

100 It is expected that vehicle-to-grid (V2G) technology will contribute to achieving a 100% smart EV percentage by 2050.

At a glance: A smart and flexible future electricity system

The smart electricity system of the future will need to be flexible, with an evolution in demand shifting and demand response from today's system. Flexibility will require new smart technologies to be developed and deployed across the electricity value chain, moving from the use of some technologies at scale to more dynamic responses from a broader range of technologies at a more targeted and granular level.

Flexible solutions that use smart technologies are already available, such as new heat pumps that can adjust to electricity consumption while maintaining temperature. We estimate that 1 GW of demand response can be unlocked, with negligible service impacts on electricity consumers, by retrofitting residential heat pumps with smart controllers at a cost of $100 million.[101] This is a much lower cost than the solutions provided by batteries, and close to the responsive capacity of Huntly power station. By using these solutions on a rolling basis, demand can be flexed at scale while minimising the impact on consumers.

Flexibility in networks

New Zealand's electricity networks currently leverage some of the flexible resources available in their systems. Electricity distribution businesses (EDBs) operate their networks within their security and capacity limits by leveraging demand response tools such as ripple control, which is the most prominent form of network flexibility today. Not only does this allow EDBs to manage their own network peaks, the spreading of loads over periods simultaneously supports the generation sector by flattening the heights of system demand.

Flexibility in retail

Today, demand response is largely enabled by peak load management from network service providers and large industrial consumers looking to reduce their electricity bills. In the smart electricity system of the future, demand-side flexibility will require electricity retailers to take an active role as well. Demand response solutions are a cost-effective mechanism for retailers to manage the risks associated with high wholesale price events, while offering new revenue opportunities through mutually beneficial arrangements with consumers.

Demand response mechanisms are also useful for network operators at the transmission level; Transpower will use ripple control to satisfy system needs on the very worst of grid emergency days. To achieve the demand dynamism necessary in the smart electricity system of the future, flexible resources need to be leveraged more regularly across all levels of the network value chain. Consequently, system operators – at both the transmission and distribution scale – will require greater visibility over the network loads available to be flexed at any given time.

While Transpower has near-perfect visibility at the high-voltage level, and EDBs can see the mid-voltage level relatively well, the low-voltage network is largely operated 'blind'. This issue of network visibility, which exists at the street level, rolls up to create operational challenges at a whole-of-network scale. As such, the system, as it is today, is forced to operate with a wide degree of tolerance built into network capacity margins in case of incorrect forecasts in available discretionary load.

To run a smarter, tighter system in the future, real-time visibility of flexible network capacity will be required across the entire voltage spectrum. In time, this will be enabled by frontloading investment in emerging low-voltage monitoring technologies and system operation platforms that leverage IoT, AI, and other smart capabilities, to schedule and call upon load flexibility in a near-automated manner when the network has and needs it.

101 Transpower identifies that 1 kW from 1 million heat pump devices each could be flexed using smart technology (Transpower, Submission to the Electricity Authority, 2021). BCG analysis finds smart heat pump devices cost NZ ~$100 per system.

While we assess that the pace of current demand-side programs and smart network initiatives are sufficient to meet today's needs, the flexibility required to meet peak demand will increase substantially to 2030 and beyond. The deployment of smart technologies will need to accelerate in the near-term to match the pace of the future system. Ensuring that electricity markets provide the right signals to attract and retain flexible capacity, as well as frameworks to enable increased demand-side participation and flexibility in networks, will be critical.

We acknowledge some practical limitations exist that could inhibit this buildout of new flexible resources on both the supply and demand side of the market, or could see existing thermal peaking capacity exiting the system, including:

- Possible shortfalls in economic incentives for new and existing peaking resources
- Possible shortfalls in widely available contract market products (e.g., price caps) for new and existing peaking resources
- Investment risks associated with building new flexible gas capacity
- Difficulty in slow-start thermal meeting peak demand for the shorter periods of time required to balance intermittent renewables through the 2020s

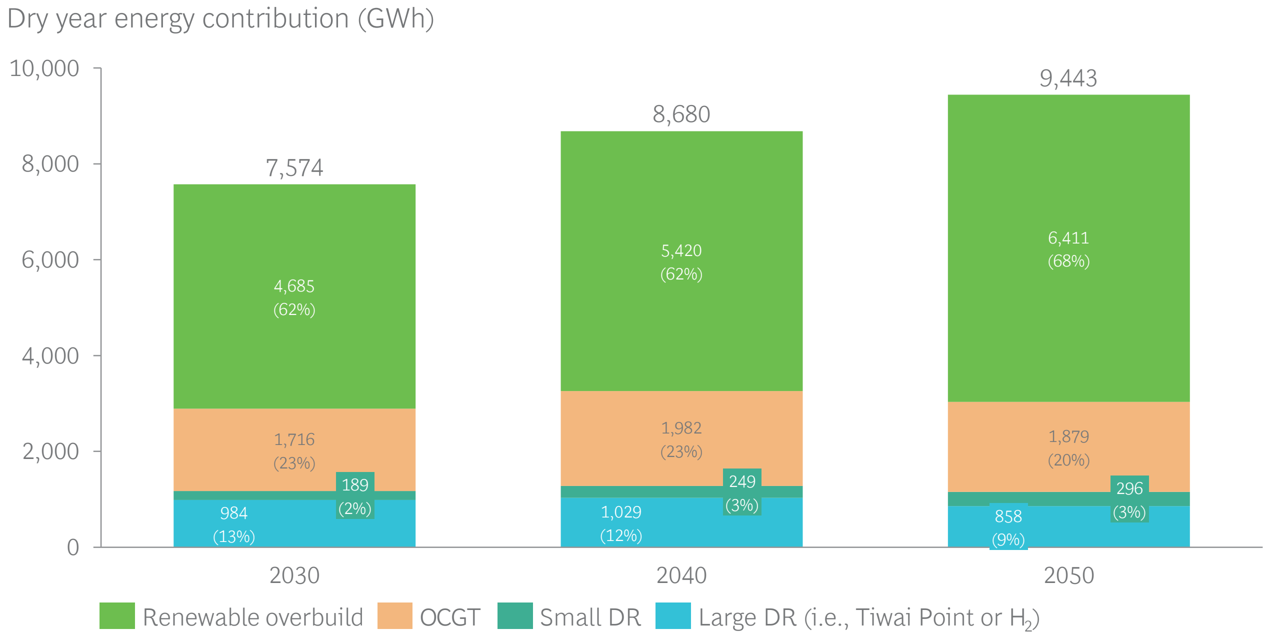
Challenge 3: Ensure sufficient flexible generation and demand energy for dry years

Under the preferred pathway, the modelling illustrates renewable overbuild, gas-fired generation, and large-scale demand response are required to meet energy needs in drier than average seasonal conditions (see Exhibit 83). The modelling emphasises the need to develop a significant portion of the wind and solar capacity that is currently unconsented in the project pipeline. It also highlights the role gas will continue to play in providing dry year cover, and the importance of demand-side flexibility under the preferred pathway.

The pipeline of flexible supply-side and demand-side resources are likely to be sufficient to meet the future system's energy needs in 2030 according to the resource mix determined by our modelling, where:

- 60% of dry year energy needs are met by renewable overbuild, provided primarily by wind and solar. The renewable pipeline and stated development intentions are sufficient to achieve this.
- The remaining 40% is met by gas and/or large-scale demand response. There is enough gas and potential new large-scale demand response projects to achieve this.

Exhibit 83: Contribution to dry energy needs



Note: Dry year energy contribution determined by the difference in spill volumes, gas generation, and demand response volumes between 2008 (wet year) and 1998 (dry year); does not include gas-fired co-generation

Source: Concept Consulting modelling, BCG analysis

We acknowledge that market conditions could realistically lead to an alternative resource mix than that identified by the model and still satisfy dry year energy requirements. However, even under several different but possible market scenarios, we believe the current pipeline of flexible resources will be sufficient to meet the system's future dry year energy needs.

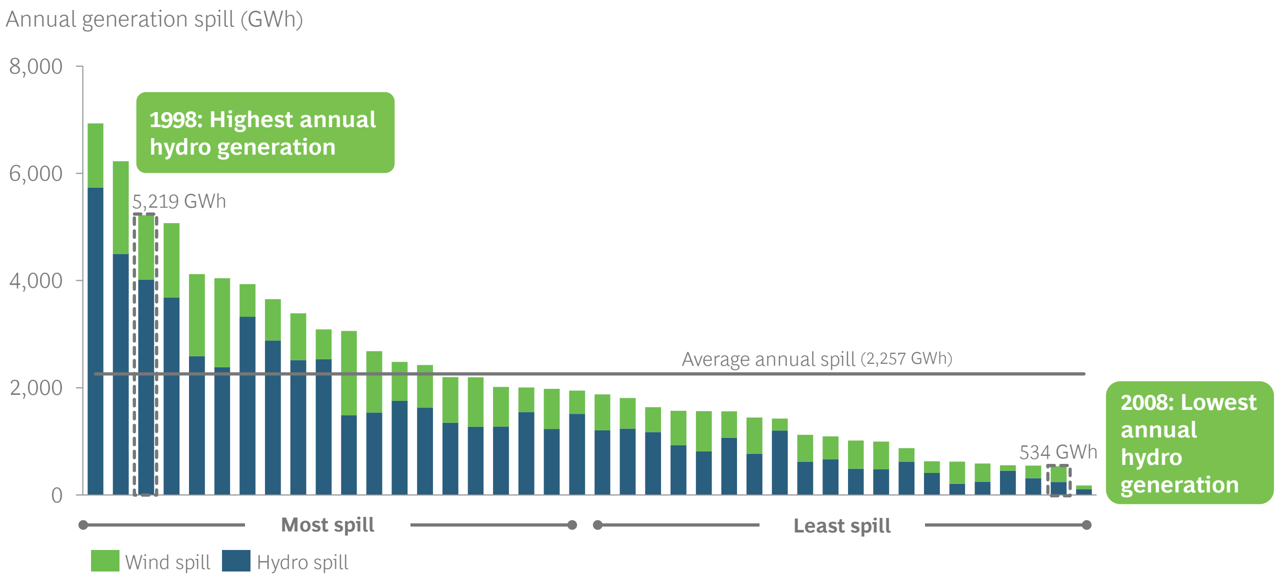
Renewables overbuild to provide dry year cover

Our modelling utilises a resource mix that results in ~5.2 TWh of wind and hydro generation being spilled (generated but not needed nor used) in 2030 under very wet hydrological conditions, which is more than double the 2.3 TWh spilled in an average year (see Exhibit 84). Under very dry scenarios, however, spill volumes fall as low as 0.5 TWh per year.

Some degree of spill is unavoidable at an inter-seasonal level because the incidence of high lake levels and plentiful renewable generation may not necessarily coincide with winter energy needs. However, an overbuild of wind and solar – to the degree necessary to ensure energy adequacy in all the hydrological conditions tested by the model – also creates the need to spill generation. This spill is first induced from hydro dams to keep lake levels within safe capacities. Wind generation is only curtailed as a secondary measure. As such, while most spill comes in the form of hydro generation, it is wind and solar overbuild that induces this degree of energy curtailment.

Our pipeline analysis suggests that investment intentions are sufficient to achieve this degree of renewable overbuild by 2030. In practice, however, the potential for overbuild to depress wholesale electricity prices could undermine investment incentives for project developers.

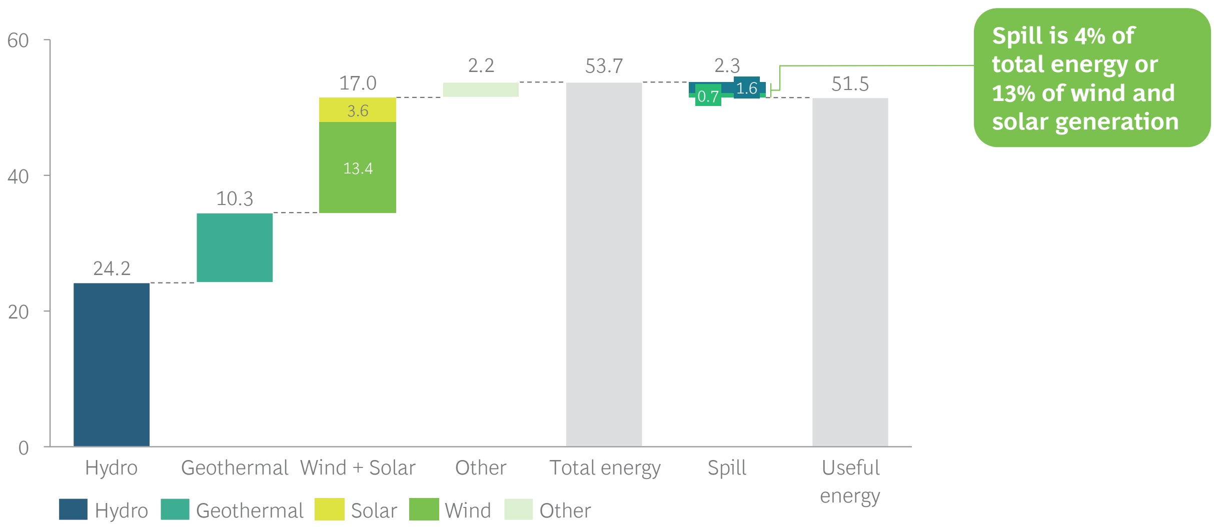
Exhibit 84: **2030 wind and hydro spill for 40 hydrological years**



Note: Shows wind and hydro generation spill in the modelling in 2030 for 40 different hydrological scenarios
Source: Concept Consulting modelling, BCG analysis

The most relevant metric to check whether overbuild is realistic in the model is average (mean) spill, which outlines the average volume of overbuild required. Average spill in 2030 is 2.3 TWh, which equates to 4% of energy being spilled, or 13% of total wind and solar generation (see Exhibit 85). This would require ~500 MW of wind and ~300 MW of solar overbuild, which is achievable in the context of declining wind and solar costs, combined with increasing costs of thermal generation. In the event renewable overbuild does not materialise to the level required, modelling has identified enough gas capacity to fill the remaining dry year energy gap (acknowledging the additional CO_2-e emissions this would bring).

Exhibit 85: **4% of total energy spilt in an average (mean) 2030 year**



Note: 'Other' includes bio energy, cogeneration, gas, and demand response; 'Solar' includes both residential and utility solar
Source: Concept Consulting modelling, BCG analysis

Gas generation to provide dry year cover

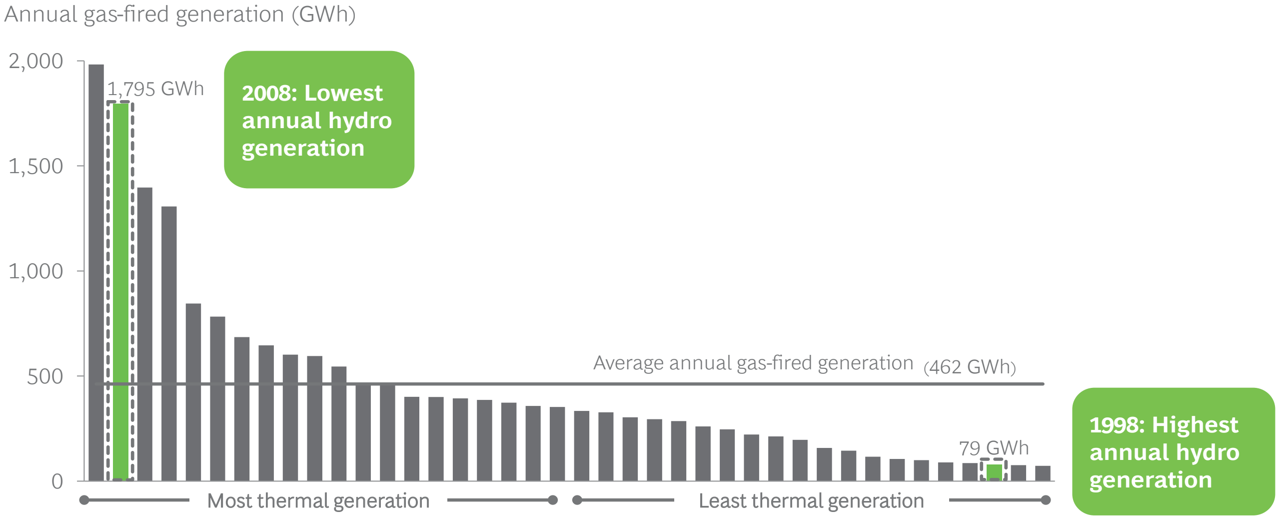
In very dry years, ~1.8 TWh of electricity comes from gas-fired generation – almost 4 times the ~0.5 TWh of generation that comes from gas-fired generation in a year of normal conditions (see Exhibit 86). If these dry hydrological conditions occur in 2030, with the renewable overbuild identified in our modelling, the 700 MW of gas capacity identified by our modelling has an annual utilisation rate of 28%, higher than the 8% utilisation rate with average weather inflows, but lower than the 34% today.

This suggests that gas generation could be further flexed to meet dry year energy needs if renewables are not overbuilt to the degree identified in our modelling. For example, if gas were to provide generation equivalent to the 4% of energy spilled in an average (mean) year, annual gas utilisation rates would increase to ~65%. As such, the model's 700 MW of gas-fired capacity could still feasibly cover dry year risk in a scenario where renewable overbuild is significantly reduced.

To achieve the 700 MW of fast-start gas capacity identified by the model under the preferred pathway, 200 MW of OCGTs will need to be developed over the course of the 2020s. However, as outlined in the previous commentary on 'Peak demand' in Section 7.3, investment and carbon risks may result in insufficient capacities of new gas-fired generation being developed to reliably meet dry year margins under the preferred pathway. In such a scenario, the possibility remains for Huntly's E3P unit to be retained by the system to provide dry year cover instead of via new gas-fired OCGT developments.

In either situation, flexibility in the future market for gas supply will be necessary to have confidence this fuel type can help meet dry year energy needs. As outlined in Section 6, Question 6 (At a glance: The gas transition), additional gas storage and/or gas demand response contracted with Methanex could support security of gas supply in a dry year.

Exhibit 86: **2030 gas-fired generation for 40 hydrological years**



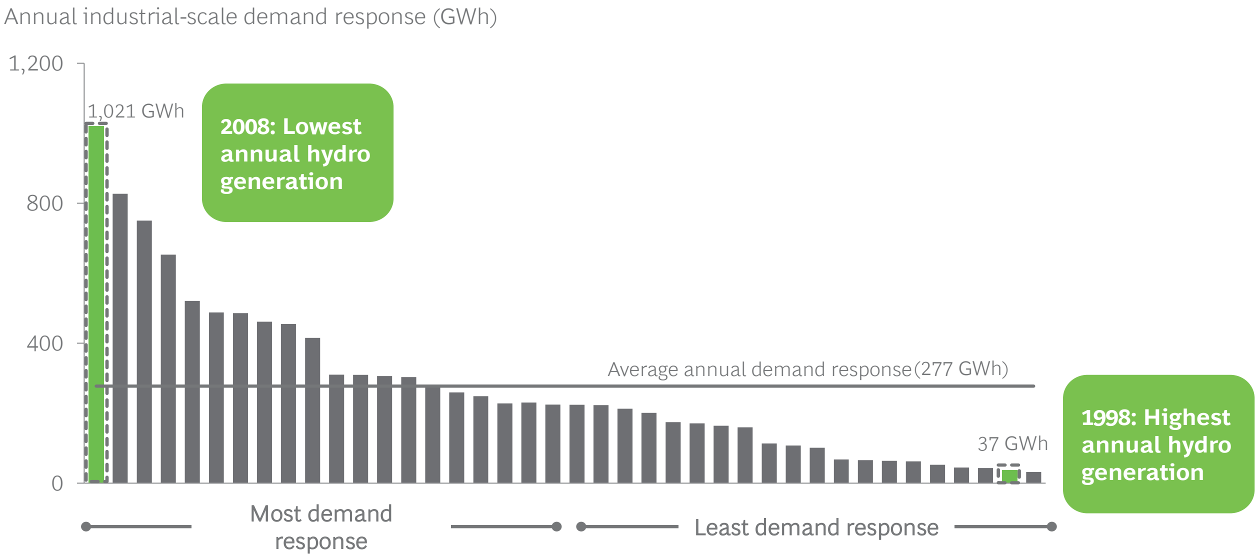
Note: Shows gas-fired generation in the modelling in 2030 for 40 different hydrological scenarios; does not include gas-fired co-generation
Source: Concept Consulting modelling, BCG analysis

Demand-side flexibility to provide dry year cover

Our modelling has also identified the need for up to 1,000 GWh of large-scale demand response to help meet 2030 dry year energy needs (see Exhibit 87). On average, however, it is expected that only 280 GWh will need to be called upon throughout the course of the year.

Today, ~250 GWh of industrial demand response is already contracted to be available for dry year cover as agreed between Meridian and the Tiwai Point aluminium smelter. However, the level of total industrial-scale demand response, which may be provided to the system through various sources, will need to quadruple within this decade to meet 2030 energy needs. Any additional demand-side energy flexibility that can be procured on top of this will further reduce the system's dependency on gas-fired generation and/or renewable overbuild for meeting dry year energy needs.

Exhibit 87: **2030 industrial-scale demand response for 40 hydrological years**



Note: Shows industrial-scale demand response in the modelling in 2030 for 40 different hydrological scenarios
Source: Concept Consulting modelling, BCG analysis

There are already several dry year initiatives underway across the demand-side of the energy sector (see Appendix 2: Decarbonisation Commitments and Initiatives). These include demand response through Southern Green Hydrogen, new flexible data centres, and technology for aluminium smelting demand response.[102]

Additionally, biomass trials at Huntly and the New Zealand Battery Project may also provide alternative, potential solutions to meet dry year needs in the case the modelled level of dry year cover does not eventuate.

We have identified some practical limitations that could inhibit the build of new flexible resources on both the demand- and supply-side of the market to meet dry year needs, including:

- Possible shortfalls in economic incentives for renewable overbuild,
- Insufficient gas security to enable gas to be a key dry year resource, and
- Costs associated with industrial demand response and/or difficulty in striking sophisticated demand-side flexibility contracts.

Challenge 4: Develop sufficient distribution and transmission infrastructure (including smart virtual infrastructure) to enable new electrification, connect new generation sources, and provide flexible capacity

Transmission

The renewables pipeline will need expansions and upgrades to New Zealand's electricity networks. From a transmission perspective, we forecast $8.2 billion of investment is required in the 2020s. Proposed grid improvements under Transpower's Net Zero Grid Pathways will commence projects this decade to increase capacity in the HVDC link, the central North Island, and the Wairakei Ring – all critical future transmission points in a world with more electrification, renewables penetration, and South Island generation.[103]

Through to 2050 regional transmission development will become increasingly important to enable renewable projects to be developed in locations that have high quality renewable resources, but insufficient transmission access. Transpower is investigating the potential for Renewable Energy Zones (REZs) to develop regional transmission. The Electricity Authority is also investigating First Mover Disadvantage rules for the Transmission Pricing Methodology (TPM) which may help regional transmission development.

We assess that it is highly likely there is sufficient transmission planned this decade for increased renewable generation and electrification under Transpower's Net Zero Grid Pathways program. However, we note that timely delivery of this transmission will be critical.

102 Further work would be required to evaluate the potential for demand response at data centres. Some of these facilities require a reliable supply of electricity.

103 Transpower, Net Zero Grid Pathways 1 Major Capex project (Staged) Investigation, 2022

Distribution

As the electricity system becomes more dynamic and distributed, it will need to accommodate multi-directional flows and more distributed resources (with greater levels of unpredictability and intermittency). The ability of networks to incorporate smart assets is important, and enabling mechanisms such as low voltage visibility, Advanced Distribution Management Systems (ADMS), and distributed energy resources will be critical to the electricity sector of the future.

The timing of this expenditure is important. As discussed in Section 6, Question 3, a proactive approach to investing in the network is required to accommodate demand uncertainty and drive uptake of new smart technologies, which have downstream benefits in terms of reducing peak demand and investment requirements over the longer term.

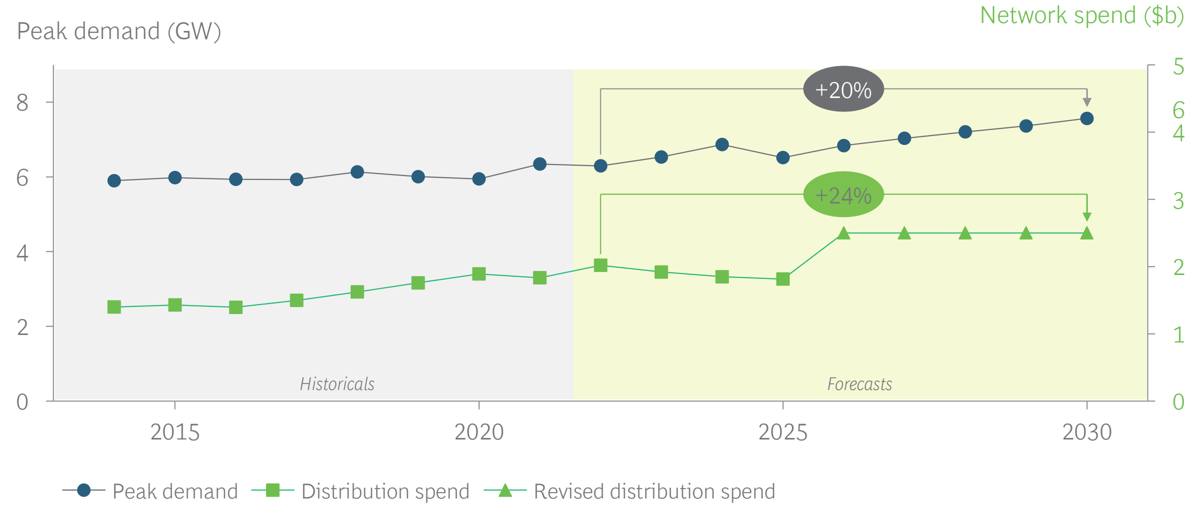
The electrical distribution businesses (EDBs) are currently in the process of integrating emissions reduction plans into their Asset Management Plans (AMPs). The Commerce Commission expects that EDBs will "play a key role in enabling decarbonisation" by responding to changing consumer demand and harnessing the opportunities presented by new technology and services.[104]

Emissions reduction plans are expected to have a sizeable impact on network investment. This will differ depending on the individual requirements of the EDB (for example, industrial consumers, population density, local geography, quality of existing network, existing network headroom, local generation and storage facilities, and local demand response and flexibility). Moreover, differences in the uptake of electrification are anticipated between urban and rural centres, which affect the degree of network investment required. EV uptake is expected to be greater in the cities, where range anxiety is less of a factor; conversely greater demand for electrification of process heat is expected in regions. This highlights the need for a whole-of-sector view to ensure each EDB can invest efficiently in its own network, noting their unique challenges and needs.

Distribution network expenditure is projected to increase, as peak demand increases. Exhibit 88 shows that distribution spend will need to increase from ~$2.0 billion in 2022, to $2.5 billion from 2026 onwards through the next Default Price-quality Path (DPP) period to build distribution infrastructure ahead of the rapid electrification in the following years. This spend requirement represents a 30% increase in 2026–2030 relative to 2021–2025. This spend growth exceeds peak demand growth in the 2020s, outlined in Exhibit 88. However this ahead-of-time investment will be important to prepare networks for electrification and to support investment in smart system enablers that will lead to longer-term savings.

104 Commerce Commission, Review of Electricity Distribution Businesses' 2021 Asset Management Plans in relation to decarbonisation, 2021

Exhibit 88: **Historical and forecast peak demand and distribution expenditure**



As discussed in Section 6.2, it is estimated that $15.2 billion of CAPEX and $6.8 billion of OPEX will be required over the next decade to enable new electrification, connect new generation sources, and provide flexible capacity.

We assess that it is highly likely that this ~30% increase in spend in 2026–2030 relative to 2021–2025 is sufficient for increased electrification provided it is supported by regulatory allowances. We also note that smart network initiatives are occurring at a sufficient pace. However, the pace of change required to enable a smart system is likely to accelerate over the next 8 years and the sector will need to increase efforts to achieve what is needed by 2030.

The step-change increase in investment will be accompanied by a large amount of activity. Building transmission and distribution infrastructure will necessitate a significant growth to the workforce over several years. This will deliver economic and socio-economic benefits across New Zealand.

We acknowledge that there may be some practical limitations that could inhibit this new transmission development, new distribution development, and smart network virtual infrastructure development, including:

- An overly restrictive RMA for network infrastructure, particularly for transmission infrastructure
- Long planning and approval lead times
- A regulatory regime that favours capital (physical build) solutions over operating (smart virtual) solutions
- Lack of sufficient funding flexibility mechanisms for distribution networks
- First mover disadvantage
- Lack of innovation funding and low voltage visibility funding
- Outdated equipment standards.

8 Policy, market, and regulatory recommendations to support the future electricity sector and achieve the preferred pathway

The electricity sector will evolve significantly over the coming decades. The future sector will deploy a range of new technologies, have a more dynamic supply profile, face increasing electricity demand, and involve a broader set of market participants.

This section discusses recommendations for policy, market, and regulations to support the future electricity sector, achieve the preferred pathway (Pathway 2: Smart system evolution) and meet the 4 energy system challenges outlined in Sections 5 and 7 of this report. Most of these recommendations are also relevant to the implementation of the other pathways outlined in Section 6.

Overview of the recommendations:

Recommendation theme	Energy system challenge addressed	Recommendations
1 Support accelerated renewables development	Renewable generation	a. Ensure consenting frameworks enable rapid deployment of renewables (high priority) b. Develop mechanisms to mitigate supply chain risks c. Improve opportunities for Iwi investment that provide community benefits d. Facilitate a deeper power purchase agreement (PPA) market
2 Encourage the right energy and capacity mix	Peak flexible resources Dry year flexible resources	e. Consider mechanisms to improve energy and capacity assurance: Recommended for implementation: • Deepen contract and derivative markets, including for demand-side (high priority) • Implement an emergency reserve scheme • Inflation index scarcity pricing • Inflation index the Customer Compensation Scheme charge • Improve forecasting • Improve tracking, monitoring, and visibility of markets and price formation Strongly recommended for further investigation: • Assess an Operating Reserve Demand Curve to enable increased reserve cover (high priority) • Assess a 30-minute reserve service Recommended for further investigation: • Assess a day-ahead market • Assess a limited dispatch mandate • Assess a retailer reliability obligation
3 Scale transmission and distribution network investment	Networks	f. Accelerate transmission development to enable renewable generation (high priority) g. Scale distribution investment to enable electrification (high priority) h. Consider options for Renewable Energy Zones

4 Enable a smart electricity system	Networks (virtual networks) Peak flexible resources	i. Improve distribution peak pricing signals and smart managed tariffs (high priority) j. Establish a framework for the formation of competitive flexibility markets (high priority) k. Update regulatory frameworks to support virtual network investment, including implementing total expenditure (TOTEX) funding (high priority) l. Mandate default off-peak electric vehicle charging (high priority) m. Enable network investment in key aspects of orchestration, including visibility and operations
5 Drive decarbonisation through electrification	General	n. Extend Clean Vehicle Standards to signal a ban on internal combustion engine (ICE) vehicle imports o. Extend GIDI funding (if required) p. Improve the Emissions Trading Scheme (ETS) in line with New Zealand's emissions targets
6 Enable the implementation of this roadmap	General	q. Deliver this whole-of-sector roadmap, including coordination with the National Energy Strategy (high priority) r. Implement a sector workforce development strategy

To support the sector to implement these changes, we have developed a roadmap for the 2020s (see Exhibit 89). It includes near-term actions to 2025 and medium-term actions from 2026–2030. This report has focused on actions in the 2020s because this is the critical decade for action and the uncertainty beyond 2030 makes it difficult to anticipate the policy, market, and regulatory evolutions needed in the longer term.

Exhibit 89: Roadmap for priority recommendations in the 2020s

Recommendation theme	2022-2025	2026-2030
Support accelerated renewables development	• Ensure consenting frameworks enable rapid deployment of renewables	• Continue to ensure consenting frameworks enable rapid deployment of renewables
Encourage the right energy and capacity mix	• Progress work to deepen contract markets • Progress investigations into mechanisms to extend reserves • Implement an emergency reserve scheme • Inflation index scarcity pricing and Customer Compensation Scheme	• Implement deepened contract markets • Implement mechanisms to extend reserves • Review efficacy of emergency reserve scheme • Review price signals to assess sufficiency
Scale up transmission and distribution network investment	• Accelerate approvals and consenting for key enabling transmission projects • Scale distribution funding for 2026-30 to enable electrification	• Deliver key enabling transmission projects • Implement efficient distribution funding flexibility mechanisms to enable investment where unforeseen needs arise
Enable a smart electricity system	• Improve distribution peak pricing signals and smart managed tariffs • Establish a framework for the formation of competitive flexibility markets • Update regulatory frameworks to support virtual network investment • Mandate default off-peak electric vehicle charging	• Continue to improve distribution peak pricing signals and smart managed tariffs • Implement roadmap for formation of competitive flexibility markets • Implement TOTEX funding framework and innovation mechanisms • Increase network investment in orchestration, including visibility and operations
Drive decarbonisation through electrification	• Further improve the ETS and policies to support transport and heat decarbonisation	• Extend Clean Vehicle Standards to signal a ban on internal combustion engine (ICE) vehicle imports • Extend and expand GIDI funding if required
Enable the implementation of this roadmap	• Develop joint industry statement of intent and action plan • Incorporate roadmap into National Energy Strategy	• Deliver this whole-of-sector roadmap and continue to monitor progress • Evolve and update roadmap as context evolves

Recommendation theme 1: Support accelerated renewables development

Our preferred pathway, Pathway 2: Smart System Evolution, requires significant investment in new renewables, with a projected 4.8 GW of utility-scale renewables capacity required by 2030. As indicated in Section 7.3, the pipeline for renewables appears strong. However, impediments such as consenting restrictions, supply chain constraints, potential constrained transmission and distribution networks, and investment uncertainty pose risks to fulfilling this pipeline. Furthermore, the right regulatory and market environment for renewables could speed up this pipeline and help New Zealand reduce its emissions earlier.

We recommend 4 actions to support the required investments in renewables to achieve our roadmap and preferred pathway:

a. Ensure consenting frameworks enable rapid deployment of renewables (high priority)

b. Develop mechanisms to mitigate supply chain risks

c. Improve opportunities for Iwi investment that provide community benefits

d. Facilitate a deeper power purchase agreement (PPA) market

a. Ensure consenting frameworks enable rapid deployment of renewables (high priority)

New Zealand's Resource Management Act (RMA), currently being revisited, poses the greatest risk to achieving the 4.8 GW of utility-scale renewable investment required this decade to achieve the roadmap. Regulatory processes, including consents and approvals, that support the projected investment required will be key to efficient renewables development and affordable electricity.

The structure and implementation of the RMA's replacement will be important to renewables development in New Zealand. Changes to the consenting regime may impact the speed and cost of new renewable developments by:

- Blocking projects that would otherwise have been consented, resulting in more expensive projects filling the 'gap'
- Increasing the overall cost per unit of projects through more arduous requirements (for example, the need to reduce the number of wind turbines on a wind farm to gain consent)
- Reducing the size of wind turbines and associated infrastructure, resulting in smaller renewable power plants
- Making repowering of existing wind farms more difficult where it is proposed that newer, better wind turbine technology is used

A more challenging consenting regime would have direct economic consequences. Modelling by Concept Consulting indicated that in a mid-range scenario – an environment where every 5th project can no longer gain consent, and the cost of remaining projects increases by 5% – the national cost of renewables development would increase by $791 million over the next 20 years. Further, because this would both increase the cost of renewables but also force consumers to pay for more expensive existing generation, the total cost to consumers was estimated at over $3 billion.

Avoiding these cost outcomes requires a replacement of the RMA that is fit-for-purpose and meets the needs of a rapidly growing electricity sector. It must be supportive of modern technologies, and appropriately consider the benefits of renewable electricity development (not just its use of resources).

It is imperative that the RMA is improved to support, rather than prohibit, the development of renewable energy and that consenting is easy and fast.

In their *Whakamana i Te Mauri Hiko Report*, Transpower highlights that the RMA's replacement should support 3 primary outcomes: grant approvals for the investments required to decarbonise the economy; grant approvals much faster; and reduce uncertainty around consenting outcomes.[105]

The primary ways the Natural and Built Environments Act (one of the 3 laws proposed to replace the RMA), or other legislation, can support these outcomes include:

- Reflecting the value of renewable electricity and associated transmission connections in addressing climate change and actively promoting lower emissions
- Ensuring greater cohesion between national policy statements regarding the value of renewable electricity and decarbonisation to New Zealand
- Aligning policy and investments to enable local government to make effective decisions that support climate change mitigation and adaptation
- Aligning resource management processes, other national and local government instruments, and settings for transmission and distribution investment decisions to the required pace for build

Review and update legislative and permitting frameworks to support offshore wind

The potential for offshore wind to contribute to New Zealand's decarbonised energy requirements is significant, however the technology is relatively immature. Today, there are no offshore wind farms in New Zealand, and the frameworks for consenting and permitting offshore wind developments are in progress.

Furthermore, due to the location of offshore wind, these farms will be influenced by several pieces of existing legislation, which need to be reviewed to adequately consider offshore wind developments. As highlighted by Venture Taranaki's Offshore Wind Discussion paper:

> *In a New Zealand context, any offshore development will be framed by several pieces of legislation including the Resource Management Act, Marine and Coastal Area Act and Exclusive Economic Zone Act, and associated regulations, and their corresponding interrelationships with the Treaty of Waitangi. It is noted that much of New Zealand's waters out to 12 nautical miles (including Taranaki waters) are subject to claims of Customary Marine Title under the Marine and Coastal Area Act. The Crown Minerals Act which regulates offshore petroleum activities will also have implications for any offshore wind development in Taranaki waters.*[106]

While continuing to develop consenting frameworks for offshore wind, we recommend government continues to review other legislative and regulatory systems to ensure an enabling framework for offshore wind.

105 Transpower, Whakamana i Te Mauri Hiko, 2020
106 Venture Taranaki, Offshore Wind Discussion Paper, 2021

b. Develop mechanisms to mitigate supply chain risks

Supply chains are significantly constrained, leading to higher prices and more prolonged delays for renewable energy equipment like solar panels and wind turbines. This poses a significant risk to achieving the 4.8 GW of utility-scale renewable development required this decade to achieve the roadmap.

Unfortunately, it is unlikely to make economic sense for New Zealand to develop its own large-scale domestic manufacturing capability for renewable energy equipment – limiting the solutions available to these supply issues.

Improving certainty, visibility, and time to procure material equipment will ameliorate the supply chain risk. This can be achieved, in part, by amending consenting processes and timelines to enable earlier equipment procurement. We recommended that as part of the implementation of this roadmap, the sector and government discuss and implement mechanisms to address supply chain constraints.

c. Improve opportunities for Iwi investment in renewables that provide community benefits

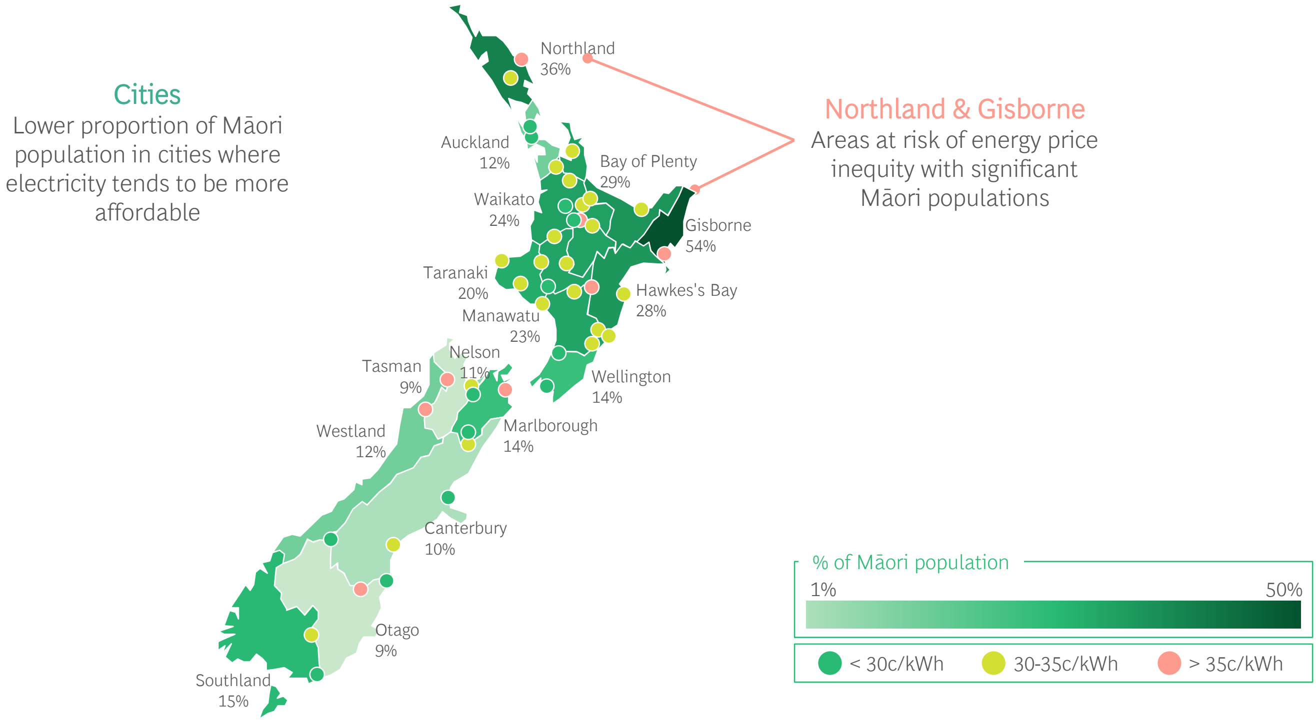
The large quantities of renewable generation required present opportunities for Iwi to invest in renewable energy, particularly where projects are hosted on their whenua (land).

There have been successful commercial partnerships with Māori landowners. For example, Mighty River Power (now Mercury) formed several partnerships in the 2000s and 2010s including the Kawerau, Ngatamariki, Nga Awa Purua, Mokai, and Rotokawa Geothermal Power Stations. In future, there is the opportunity for more substantial partnerships to be developed with increased Iwi equity stakes.

Throughout the energy transition, we recommend the sector and government consider how to improve energy inequities for Māori, and whether new power stations that are owned or co-owned by Iwi can assist with this.

Exhibit 90 below illustrates energy inequity for Māori. The 2 regions with the highest relative proportion of Māori population – Northland and Gisborne – also have high electricity prices. Furthermore, in cities where electricity prices tend to be lower, Māori tend to have a lower relative proportion of population.

Exhibit 90: **Māori population and retail electricity price**



Note: Retail electricity price is calculated as average quarterly price over a five year time period; population proportion figures use 2018 data.
Source: Stats NZ; MBIE; BCG analysis

It may be possible for Iwi investments in generation projects to provide local Māori with lower cost energy by establishing a community retailer that receives power from the local project via a PPA.

Distributed and localised energy solutions like distributed solar and batteries can also improve Māori energy equity and enable greater self-sufficiency of energy production for Iwi. In August 2020, the New Zealand Government implemented a $28 million Māori and Public Housing Renewable Energy Fund to trial small-scale renewable energy technologies.[107].

107 Ministry of Business, Innovation and Employment, Māori and Public Housing Renewable Energy Fund, 2020

d. Facilitate a deeper power purchase agreement (PPA) market

For independent renewable generators, some certainty around future returns is often a requirement for a final investment decision. This is often achieved by signing long-term, fixed-price contracts (e.g., 10-20 years) for some or all the output of a renewable asset with one or more counterparties. These contracts are referred to as PPAs.

These agreements can benefit both signatories: PPAs provide steady and certain income for new generation projects and reduce project risk so investors may accept a contract price at a discount to spot prices. This can also provide the off-taker with a steady, certain, and competitive price and secures their electricity supply over the long term.

New Zealand's PPA market is relatively shallow and is currently led by members of the Major Energy Users Group (MEUG). Outside of this group, PPA use is limited. However, there are potential benefits of PPAs to commercial energy consumers and developers.

MBIE's report Accelerating renewable energy and energy efficiency outlined 4 potential options for a new PPA market to encourage further investment.[108] These are summarised below:

A	**Contract matching service**	Provide seed funding via a tender to set up and operate a contract matching service that could provide information, resources, a network of energy buyers and project developers, inexpensive training, and advice on PPA requirements. This would address information barriers or lack of legal and contracting expertise.
B	**State sector-led**	State sector entities could electrify, aggregating off-takers like councils and hospitals, alongside corporate entities. This could be coordinated within a state sector decarbonisation program and administered alongside the Government's electricity contract.
C	**Government guaranteed contracts**	Government could guarantee/underwrite PPAs to lower the contract strike price. This option could target small businesses and community projects with significant local co-benefits, such self-sufficiency, grid resilience, and reduced electricity bills. It may also support regional economic development.
D	**Clearing house**	A platform could both buy and sell PPAs, acting as a contract clearing house. The platform could aggregate and match supply and demand, without requiring one-to-one contract matching, hedging any residual exposure to electricity prices. This would only be made accessible to new loads and new renewable electricity generation projects.

Of the above options, each have their own advantages and drawbacks. We do not recommend Option C as it would be distortionary and could lead to perverse outcomes. However, options A, B, and D could facilitate a deeper PPA market with further investigation.

108 Ministry of Business, Innovation and Employment, Discussion document: Accelerating renewable energy and energy efficiency, 2019

Case study: Melbourne Renewable Energy Project

Under this project, 14 members of a buying group combined their purchasing power to support the construction of the 80 MW windfarm at Crownlands, near Ararat, owned and operated by Pacific Hydro. This is the first time in Australia that a group of local governments, cultural institutions, universities, and corporations collectively purchased renewable energy from a newly built facility. The new windfarm in regional Victoria began supplying energy to power town halls, bank branches, universities, and streetlights across Melbourne. The City of Melbourne council is now powered by 100% renewable energy.

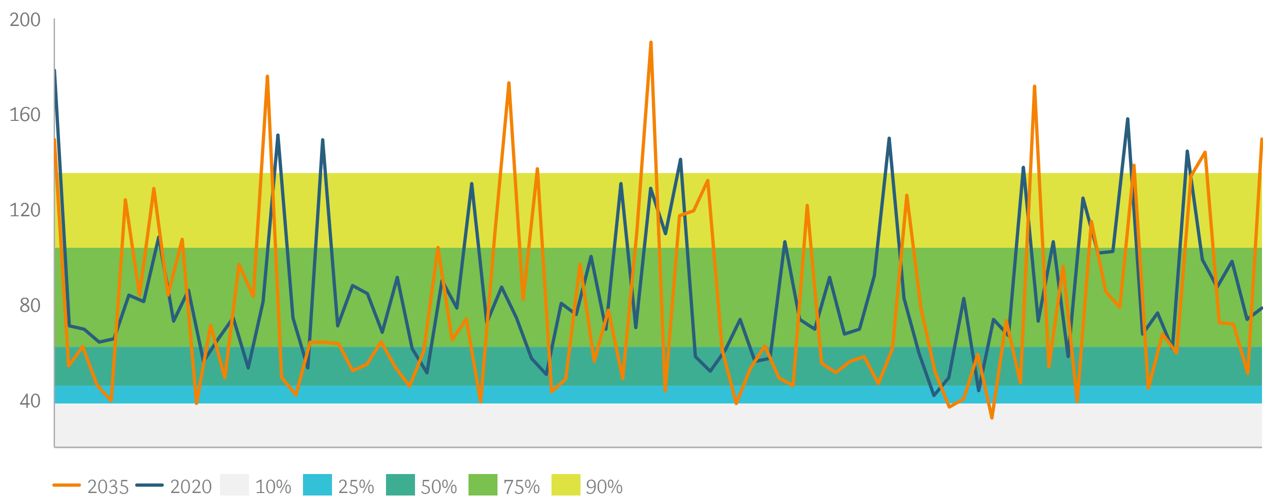
Recommendation theme 2: Encourage the right energy and capacity mix

Market transition context:

The future electricity system is likely to experience greater volatility as the technology mix evolves, particularly as the electricity system nears 100% renewable electricity (see Exhibit 91). As intermittent renewable generation increases, traditional dispatchable capacity will provide less baseload energy. Meanwhile, intermittent renewables will create greater unpredictability around when, and for how long, dispatchable assets will be required.

Exhibit 91: **Projected increase in price volatility under a 100% renewables pathway in 2035 vs 2020**

2020 current system vs 2035 100% renewable pathway annual price distribution $/MWh



Source: Concept Consulting

This leads to the following dynamics through the transition:

1. **Declining value of existing slow-start thermals:** Unpredictable daily demand and weather dependent supply will challenge existing slow-start generators to provide capacity at short notice. Furthermore, operators of slow-start generators may rationally decide to not start, even with sufficient notice, where the chance that they are required is low. These slow-start units, which are used to derive spot market revenue from dry years and peak periods, will be more reliant on dry years for revenue, which occur infrequently. This will likely be an issue in the transition in the 2020s until slow-start capacity can be replaced.

2. **Increasing need for new fast-start capacity:** New fast-start capacity will be needed to support increasing peak demand and intermittent supply. Batteries, open cycle gas turbines (OCGT), and dynamic demand response, among other fast-start resources, could provide the required flexibility in the 2020s. However, the cost of batteries is not yet economic to deploy them at a very large scale, there is significant carbon risk to developing new OCGT plants, and the smart system enablers for dynamic demand response are only emerging. These issues are likely to be resolved by 2030, as technology costs, technology solutions, and system smarts for fast-start capacity evolve significantly – but present an issue for the 2020s.

3. **Increasing need for demand-side solutions:** Increased demand-side flexibility has been touted for decades as a solution to meeting peak demand but has not substantially materialised. One reason is that customers are often exposed to smoothed or flat tariffs, which can mute the incentive to respond to peaks. Another reason is that the system smarts and markets have not yet evolved to enable broad-based, near real-time demand-side participation in markets.

4. **Lower utilisation of peaking capacity:** In a market with 98%+ renewable electricity, flexible supply-side resources will be required for fewer, but higher priced, events. As the use of these peaking assets will be low and inter-year revenue volatility may increase, mechanisms may be required to smooth infrequent, high price events into longer-term contracts to provide a better long-term signal for investment.

In theory, New Zealand’s energy-only market should provide the required signals to overcome these challenges. A shortage of capacity should drive up electricity prices, increasing the incentive for generators and retailers to invest in new flexible resources.

Existing mechanisms in New Zealand also reinforce signals for capacity. For example, swaption contracts signal the value that market participants place on different types of capacity and provide regular revenue for assets that would otherwise rely on spot market events for revenue. Retailers are also incentivised to hedge with peaking and dry year generators to mitigate risk across their customer books.

In practice, however, market uncertainty can create a significant barrier for generators seeking to maintain flexible assets and develop new ones. This is compounded by political realities – the political palatability of sustained periods of elevated wholesale market prices, or more frequent blackouts, may be in stark contrast to the economic value ascribed to these outcomes by the wholesale power market.

The future of energy-only markets

BCG has written extensively in recent months on the future of electricity markets at close to 100% renewable electricity.[109,110,111] Our view is that, in the New Zealand context, the energy-only market is the right solution for the foreseeable future. This is assisted by the fact that New Zealand does not have significant subsidies for new renewables or storage, which can mute the efficacy of the energy-only price signal.

A range of potential mechanisms have been deployed globally to underpin investments and deliver energy capacity. When considering these mechanisms for New Zealand, we are cognisant that New Zealand already has a well-functioning electricity market that has delivered good trilemma outcomes. Its comparatively pure, energy-only electricity market has sent price signals that have incentivised efficient investment for more than 2 decades.

However, energy-only markets will need to evolve significantly to ensure that price signals maintain sufficient investment through the transition towards 100% renewable electricity. This will be important to address the following outcomes:

- The price signal for investment in peaking and dry year solutions incentivises new investment
- Price signals and market arrangements can increase demand-side contribution to meeting peak demand and energy needs
- The system is incentivised to meet unexpected declines in intermittent renewable generation
- Slow-start thermal plants are committed to starting when needed
- In the event of an emergency, all available resources are used before resorting to cutting off consumers' power

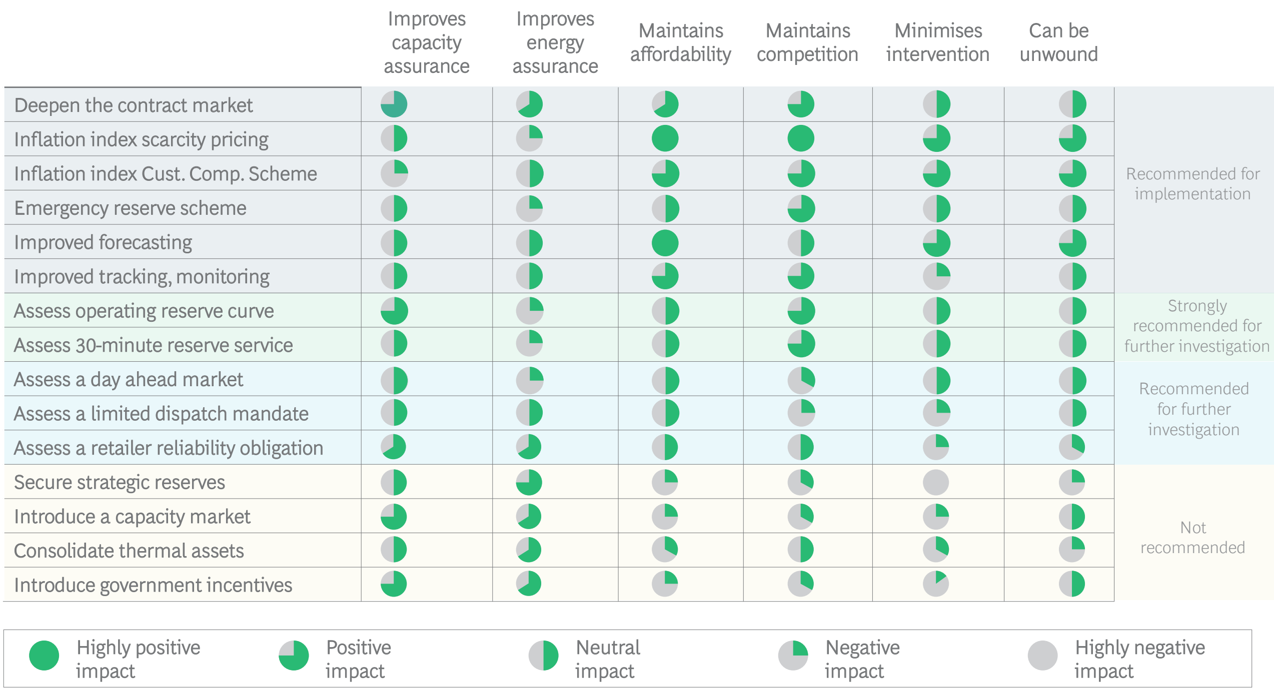
We recommend implementing the mechanisms that enhance and improve the energy-only market and improve monitoring to assess whether these mechanisms are working effectively, with the fewest drawbacks. If these mechanisms are insufficient, further mechanisms can be implemented.

109 BCG, Why your company needs to be an electricity trader, 2021
110 BCG, Will electricity be free? Not when you really need it, 2022
111 BCG, Is electricity pricing running out of gas, 2022

e. Consider mechanisms to improve energy and capacity assurance

We outline 15 potential mechanisms that may address capacity and energy assurance as New Zealand's electricity sector transitions (see Exhibit 92). We also consider the extent these mechanisms require significant upfront or ongoing intervention, as well as outcomes that are potentially difficult to unwind.

Exhibit 92: **Comparison of mechanisms to improve capacity & energy assurance**



Recommendation

Deepen contract and derivative markets, including for demand-side (high priority)

Assists with: Providing revenue adequacy to existing flexible resources, providing revenue adequacy to new flexible resources, and assisting increased demand-side participation.

This is the most sensible, least regrets reform that we recommend takes place. To have a well-functioning energy-only market, it is important that the contract market evolves through time to continue to provide sufficient optionality for market participants to appropriately manage their risk.

The contract market is a way of providing additional market-based revenue streams for flexible assets while maintaining an energy-only market. Contracts are already used within the New Zealand electricity sector, as generators and retailers hedge their risk across a range of supply and demand scenarios. A well-cited example in New Zealand is the swaption agreements held between hydro and thermal generators to balance wet year hydroelectricity and dry year thermal supply coverage.

The key benefit of leveraging contracts to drive appropriate capacity and energy assurances is that it is a market-driven approach; there is minimal regulatory burden required and the market can innovate and drive administration costs down.

Through the 2020s, the electricity system will transition quickly from one that consists primarily of baseload, mid-merit, and flexible resources today, to one that consists of mostly intermittent and flexible resources in the future. This will change hedging and contract market requirements. For example, baseload contracts may not provide the level of sophistication needed for some market participants in future with this more dynamic and volatile electricity system.

BCG analysis has also identified that, as more 'price opportunist' resources like batteries, short-duration storage, and time-critical demand response like EVs and household response enter the electricity system, longer-term contracts will become increasingly important for price formation in energy-only markets.[112]

Additionally, as most peaking assets transition to lower rates of utilisation, with fewer high price events it will be important to have mechanisms that can smooth out revenue to provide a longer-term price signal. This will assist with supporting investment in new peaking capacity.

The creation of new tradeable options, as well as the lengthening of contracts and futures beyond 3 years, may provide new opportunities for market participants to incentivise and remunerate their forward energy requirements. Cap contracts are an example of a tradable option that is popular in Australia (see At a Glance below), which this report identifies as something that should be implemented in New Zealand.

At a glance: Cap contracts in Australia provide a substantial portion of generator revenue

Cap contracts (contracts that represent an option to call on generation capacity when power prices hit a certain level) are a mechanism that can underpin investment in developing new capacity and maintaining existing capacity. As highlighted on the website of the Australian Energy Market Commission, under a cap contract:

- A fixed volume of energy is traded during a fixed period for a fixed price but only when the spot price exceeds a specified price.
- The standard cap contract traded in the market is a '$300 cap'. This means the seller of a cap is required to pay to the buyer the difference between the spot price and $300/MWh every time the spot price exceeds $300/MWh during the specified contract period. Note that, in New Zealand, the right price level would need to be investigated and it could be higher than $300/MWh.[113]

In exchange for the option to call on the cap, the buyer of the cap contract pays ongoing revenue to the provider of the contract. Often this revenue can cover or exceed the generator's fixed costs, providing a stable revenue stream to underpin the investment in the asset. Therefore, the generator only requires additional revenue that covers variable generation costs (i.e., the cost of fuel) and some incremental margin for an adequate return on investment.

Similar contracting mechanisms exist in New Zealand as swaptions, however, they are largely bilateral. Making these available to the open market would increase liquidity, enable improved hedging for retailers, and provide broader revenue opportunities for generators. This is one key difference between the ASX listed futures and options between New Zealand and the much more liquid contract market of Australia. However, for the market to deepen and cap contracts to be viable on the open market, existing generators may need to offer greater capacity into the market, an issue that has been raised previously by the ASX.

112 BCG, Is electricity pricing running out of gas, 2022
113 Australian Energy Market Commission, Spot and contract markets, 2019

The types of contracts that are likely to be required are:

- **Cap contracts:** A call option for generation or demand capacity over a certain price for a fixed period of time.
- **Time limited cap contracts:** Time limited call options for generation or demand capacity over a certain price. This will be very valuable when shorter duration demand response and batteries emerge at scale. Some of these resources may only be able to provide ~1 hour of sustained response, which may not work under standard cap contracts. Time limited cap contracts would assist with promoting demand-side participation in markets.
- **Super peak contracts:** Contracts that supply during defined peak periods. For example, this could include winter evenings in New Zealand. Super peak contracts have already emerged in Australia.[114]
- **Sleeves:** Flexibility contracts to firm intermittent generation. Sleeving contracts can be used in conjunction with renewable energy PPAs to provide a firmed renewable supply.

Improving the liquidity and tenure of the contract market may also bring other benefits. Liquidity is generally recognised to reduce market costs (i.e., both cost of transaction and cash holding requirements), ultimately lowering power bills.

To enable the development of these contracts, some new market evolution may be required. This can include market-making arrangements or other means to establish the necessary frameworks to ensure new contracts are able to be established with sufficient liquidity.

We recommend that government, regulators, and the sector consider options that encourage the deepening of the contract market as a low-regret intervention.

Deepen contract market	Impact	
Improves capacity assurance	Somewhat positive	• Should improve mechanisms for market to contract (and incentivise) required capacity yet limit central control over outcomes
Improves energy assurance	Somewhat positive	• Should improve mechanisms for market to contract (and incentivise) required energy yet limit central control over outcomes • Maintains strong price signals for dispatch from energy-only market
Maintains energy affordability	Somewhat positive	• Limited regulatory overhead required to implement • Increased liquidity may encourage new entrants which may lower costs
Maintains market competition	Somewhat positive	• Increased liquidity may encourage new market entrants
Minimises intervention	Neutral	• Limited regulatory oversight required; price-setting completed by market • May require some level of intervention to ensure sufficient capacity is offered into the contract market
Can be unwound	Neutral	• Difficult to unwind but minimal downside to maintaining deeper market

114 Renewable Energy Hub, New era for renewables as first new super peak firming contract signed, 2020

Recommended mechanism

Implement an emergency reserve scheme

Assists with: Ensuring all resources are available in a system emergency and incentivising meeting peak demand by apportioning costs to participants if emergency reserves are needed

A critical component of operating an efficient power system is ensuring that all available resources are in use at the time of an emergency. While this sounds simple in theory, in practice, 'shaking the tree' to access all available resources on the system is often more difficult. One important step is for the system operator to improve visibility of discretionary load on the system to enable improved emergency management. We understand that Transpower has this activity underway.[115]

An additional and complementary way to ensure all resources are available is to implement an emergency reserve scheme, which enables unscheduled load and generation (i.e., load and generation that does not actively participate in the electricity market) to be activated in an emergency event where supply falls short of demand. Modelling under the preferred pathway identified that up to 300 MW of involuntary demand response would be required for one hour per year in 2030. An emergency reserve scheme could formalise contracts to ensure that this short period of need is supplied by emergency demand response that is contracted through an emergency reserve. This would ensure that no involuntary demand would be required for a modest cost of covering one hour of additional capacity per year.

By targeting unscheduled load and generation, a reserve scheme enables resources that are outside of the market to be captured within the market, which ensures that additional resources that exist today can be utilised.

Australia's Reliability and Emergency Reserve Trader[116]

Australia's Reliability and Emergency Reserve Trader (RERT) is a mechanism that enables the system operator AEMO to maintain power system reliability and system security using reserve contracts:

- If AEMO assesses that forecast reliability and security will be outside a relevant market standard, and it considers there is no market resolution to it, then it may choose to procure RERT reserves.
- AEMO maintains a panel of RERT providers who can provide resource commitment at short notice (3 hours to 7 days) and medium notice (7 days to 10 weeks). If AEMO predicts longer-term shortages, it can procure long-term RERT reserves (10 weeks plus).

115 Electricity Authority, 9 August 2021 demand management event, 2022

116 AEMO, Reliability and emergency reserve trader (RERT), 2021

In New Zealand, this would be a pragmatic way to provide Transpower as system operator with a mechanism to cover any forecast shortfalls to meet system reliability needs. One way to ensure an emergency reserve is more effective is to apportion the costs paid to these emergency reserve resources to retailers. This provides an economic disincentive for retailers to enter a situation where emergency reserves are needed and is likely to increase the incentive to develop or contract with flexible peak resources that reduce the need for emergency reserves.

Emergency reserve scheme	Impact	
Improves capacity assurance	Somewhat positive	• Ensures emergency capacity is available when needed • Provide stronger incentive for retailers to hedge for peaks as the cost of the scheme would be apportioned to them if it is needed
Improves energy assurance	Neutral	• Does not impact incentives for energy
Maintains energy affordability	Neutral	• Likely to come at some cost but should be modest if only used to cover highly rare events
Maintains market competition	Somewhat positive	• Open tender for system operator enables most cost competitive resources to provide services
Minimises intervention	Neutral	• Requires some intervention to establish the mechanism but is run by competitive tenders by the system operator if required once established
Can be unwound	Neutral	• Could be unwound but market may develop dependence on it

Recommended mechanism
Inflation index scarcity pricing

Assists with: Providing revenue adequacy to existing flexible resources, providing revenue adequacy to new flexible resources and assisting demand-side participation.

Efficient energy-only markets require sufficiently high price ceilings to send efficient price signals for peaking resources. This will become much more important as peaking resources will rely on fewer, but higher price events to generate revenue adequacy. There is no price ceiling in the New Zealand electricity market except for in the event where there is emergency load shedding. In this instance scarcity pricing is implemented which puts in place a price floor of $10,000 per MWh and a price ceiling of $20,000 per MWh. According to the Electricity Authority this is designed to deliver “improved revenue certainty for providers of last resort resources (generation and demand response), while also giving more assurance to wholesale purchasers that spot prices in emergency load shedding will not settle well above the level expected”.[117]

117 Electricity Authority, Scarcity pricing, 2015

Scarcity pricing was implemented in June 2013 and has remained flat in nominal terms, leading to declines in real terms. If scarcity pricing was inflation indexed to today's dollars this would lead to an updated $12,200 price floor and a $24,400 price ceiling. This would provide a consistent price signal each year in the event where supply falls short of demand. We recommend inflation indexing occurs and that scarcity pricing is updated annually to adjust with inflation.

Inflation indexing price ceilings occurs in the National Electricity Market (NEM) in Australia. While the NEM price ceiling is not a scarcity price, it is a useful comparator example.

Inflation index scarcity pricing	Impact	
Improves capacity assurance	Somewhat positive	• Should send stronger price signals for capacity
Improves energy assurance	Neutral	• Maintains strong price signals for dispatch from energy-only market
Maintains energy affordability	Somewhat positive	• Limited regulatory overhead required to implement • Increased capacity signals may lower overall costs
Maintains market competition	Neutral	• Does not impact competition
Minimises intervention	Neutral	• Limited regulatory oversight required; price-setting completed by market
Can be unwound	Somewhat positive	• Relatively easy to unwind or change

Recommended mechanism
Inflation index the Customer Compensation Scheme charge

Assists with: Providing revenue adequacy to flexible resources for meeting dry year energy needs

The Customer Compensation Scheme (CCS) is a mechanism that charges electricity retailers $10.50 per customer per week of electricity supplied when an Official Conservation Campaign (OCC) is triggered in a dry year. An OCC is a last resort mechanism that asks consumers to conserve energy use in a dry year. The CCS serves as a disincentive for entering an OCC as this is an undesirable outcome for consumers.

The CCS was implemented in 2011 and has remained flat in nominal terms and has declined in real terms. Inflation indexing the CCS to today's dollars would lead to a charge of $13.10 per customer per week. Increasing the compensation payment would increase the incentive for retailers to hedge their exposure to this price through agreements with generators. We recommend inflation indexing occurs and that the CCS is updated annually to adjust with inflation.

As more intermittent generation enters the electricity system, and 95%+ renewables is achieved this decade, the value of slow-start thermal power plants for meeting peak demand will decline significantly as there will be an increasing need for faster, more responsive flexible assets to come in and out of the market to balance intermittency. However, slow-start thermal power stations will still be required for most of this decade to provide dry year support. If the reduction in peaking revenue makes the economic case tenuous for slow-start thermals to remain in the market, then this could compromise New Zealand's ability to have sufficient dry year cover through the transition to new dry year solutions.

The OCC charge is an existing mechanism that could be ramped up even beyond the recommended inflation indexed level to provide a stronger incentive for dry year cover. This would also lead to greater contracting by retailers to cover dry year. It would be a relatively elegant way to dial up the incentive for dry year cover, ensure slow-start thermals remain in the market for long enough, and incentivise the development of new renewable dry year solutions. This would ensure a market driven approach to solving dry years.

One implication of increasing the OCC charge is that it may necessitate increased market-making in dry year contracts to ensure that independent retailers are able to hedge their increased exposure effectively. Genesis Energy already appears to be commencing this dry year market making which is encouraging through an expression for interest for Market Security Options.[118] Another implication to consider is how an increased OCC may impact hydro generator risk tolerance and the impact this would have on hydro spill.

CCS inflation indexation	**Impact**	
Improves capacity assurance	Neutral	• This measure would not influence capacity outcomes
Improves energy assurance	Positive	• Improved incentives for energy to cover dry years
Maintains energy affordability	Somewhat negative	• The price of the increased charge would likely be reflected through additional dry year contracts and physical dry year resource
Maintains market competition	Neutral	• The mechanism still relies on a market driven approach to solving dry year
Minimises intervention	Neutral	• Centrally directive but is only a change to an existing mechanism
Can be unwound	Positive	• Relatively easy to discontinue with some risk of having set a market precedent

118 Radio New Zealand, Genesis Energy calls for interest in market security options, 2022

Recommended mechanism

Improved forecasting

Assists with: More accurate signalling of electricity spot market and reserve market resource requirements

As more weather dependent intermittent generation like wind and solar enters the electricity system, more accurate forecasting will become increasingly important to signal resource needs and to ensure efficient system operation. If system needs are able to be more accurately defined ahead of time, this will assist some slower-start resources (including some demand response that requires notice of minutes to hours) to make more informed commitment decisions in anticipation of need.

This will become even more critical if new reserves markets like 5-minute and 30-minute reserves are implemented to assist with providing additional resource cover ahead of time to balance intermittent renewables.

One example of improved forecasting is United Kingdom's system operator National Grid collaborating with the Alan Turing Institute to use advanced data and analytics to deliver a 33% improvement in its solar forecasting.[119] Several improvements to electricity forecasting have been recommended in New Zealand, including disallowing persistence forecasting from wind generators.[120] Through time, increasingly sophisticated forecasting will be needed to signal the needs of a more dynamic and variable system.

Improved forecasting	Impact	
Improves capacity assurance	Somewhat positive	• Provides greater signals to capacity about need
Improves energy assurance	Somewhat positive	• Provides greater signals to energy about need short-duration (minutes to days) need
Maintains energy affordability	Positive	• Improved forecasting will lower system costs as it more accurately defines resource needs, reducing need for additional redundancy
Maintains market competition	Neutral	• Increased information will assist all participants
Minimises intervention	Somewhat positive	• Is a simple mechanism implemented by the system operator
Can be unwound	Somewhat positive	• Unlikely to be need to unwind better forecasting

119 The Energyst, National Grid and Alan Turing Institute improve solar forecasting, 2019

120 Electricity Authority, 9 August 2021 demand management event, 2022

Recommended mechanism

Improved tracking, monitoring, and visibility of markets and price formation

Assists with: Better informed purchasing and selling of electricity to assist with deepening contract and derivative markets

An important element of efficient markets is good information. Improved tracking and monitoring of market performance will assist with identifying if and how the energy-only market is falling short of sending sufficient price signals for investment.

Improved visibility of price formation will assist market participants with making more informed buying and selling decisions, particularly as it relates to a deepened contract and derivatives market. In many international electricity markets, price formation is usually simpler to determine than in New Zealand as the market resources that bid into the market are often short-run marginal cost driven (i.e., coal and gas). In New Zealand, hydroelectricity forms a significant portion of generation, and its pricing is often based on more complex water option values that incorporate lake levels, forecast demand, generation, and rainfall.

This can make it difficult for some purchasers of electricity to make informed decisions. For example, it may not be apparent to an industrial consumer how a PPA sleeve should be priced to firm a wind farm PPA offtake.

In time, access to improved price formation information will assist with the formation of a deeper contracts and derivatives markets.

Improved tracking and monitoring	Impact	
Improves capacity assurance	Somewhat positive	• Enables improved information for market participants to hedge and invest
Improves energy assurance	Somewhat positive	• Enables improved information for market participants to hedge and invest
Maintains energy affordability	Neutral	• Likely to be some cost to comply with requirements
Maintains market competition	Somewhat positive	• Increased liquidity may encourage new market entrants
Minimises intervention	Somewhat negative	• Will require rules to require information disclosure
Can be unwound	Somewhat positive	• Can be unwound if it proves to be of low value

Strongly recommended for further investigation: Assess an Operating Reserve Demand Curve to enable increased reserve cover (high priority)

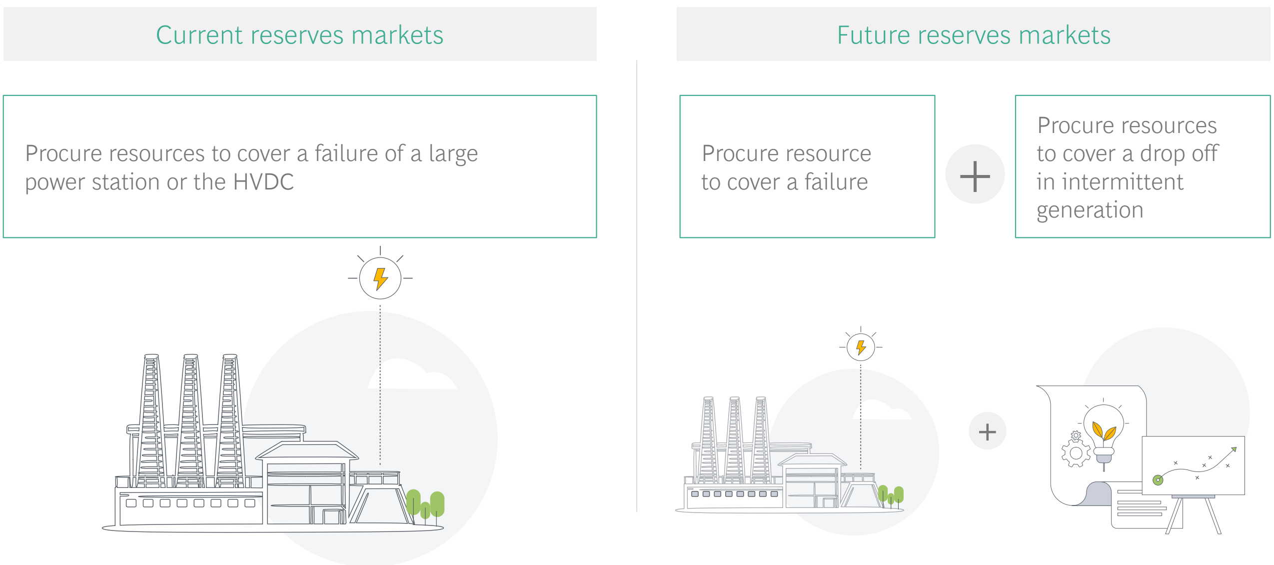
Assists with: Ensuring enough fast-start capacity to balance intermittency and providing additional revenue streams for flexible resources to send sufficient price signals for investment

Today, New Zealand has fast instantaneous reserves (FIRs) and sustained instantaneous reserves (SIRs) to balance the electricity system in the event of a sudden increase or decrease in load and/or generation. FIRs must be provided within 6 seconds of a contingent event (or one second after the frequency falls to 49.2 Hz for interruptible load) and sustained for 60 seconds. SIRs must be provided within 60 seconds after a contingent event occurs and sustained for at least 15 minutes.[121] The level of reserve carried is enough to cover the most credible contingent event, which is usually either the sudden failure of a large generating plant or the HVDC link. As well as providing a very valuable service to the electricity system, this also provides an additional revenue stream for fast-start load and generation.

In future, it is likely that increased and different types of reserves will be required to manage evolving and more dynamic system conditions during the transition to close to 100% renewable electricity. In time, the most credible contingent event in terms of size could be a sudden, unexpected drop in weather dependent generation, which would even exceed the failure of a large power station or the HVDC. To make matters more complex, a system with appropriate risk management will provision reserves for both potential drops in weather dependent generation and a failure of a large power station at the same time (see Exhibit 93).

On August 9th, 2021, this was the exact set of circumstances that, amongst other drivers, led to a blackout. At almost the same time that Tokaanu hydro power station lost 200 MW of generation due to a weed blockage, wind generation fell off by 200 MW.[122] In a similar set of circumstances, the August 9th, 2019, Great Britain blackout was caused by the simultaneous failure of a gas power plant and an offshore wind farm. While the offshore wind farm production decline was not caused by a sudden drop off in wind speeds, this event had broadly the same effect.[123]

Exhibit 93: **Illustration of how increasing levels of intermittent generation will require increased reserves cover**

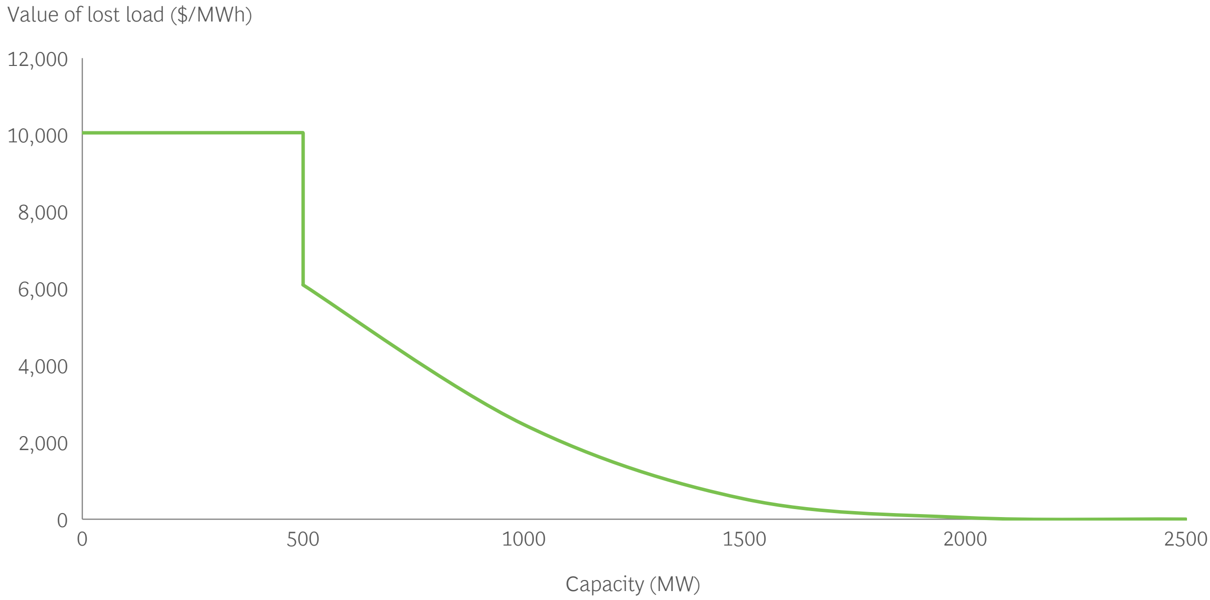


121 Electricity Authority, Review of instantaneous reserves market project, 2018
122 Ministry of Business, Innovation and Employment, Investigation into electricity supply interruptions of 9 August 2021, 2021
123 Department for Business, Energy & Industrial Strategy, GB power system disruption – 9 August 2019, 2019

Provisioning reserves for intermittent generation is not simple. For example, carrying reserves at all times for the total level of intermittent generation in the market would be cost prohibitive and impractical. A more economic carrying of intermittency reserves would determine the level of reserve required based on system conditions (i.e., how tight the system is running) and based on probabilistic assessments of the likelihood and level of intermittent generation that could decline.

This will require a deeper and more sophisticated reserve market and more sophisticated forecasting. An Operating Reserve Demand Curve (ORDC) enables a dynamic way to price reserves at different levels. ORDCs are currently implemented in Texas' ERCOT market and in the United States' eastern seaboard Pennsylvania – New Jersey – Maryland market.

Exhibit 94: Illustration of an Operating Reserve Demand Curve



The price of the reserves outlined in the above Exhibit 94 and the level of reserves procured can follow the probabilistic assessment of the volume of reserve needed. Professor William Hogan, the research director for the Harvard University Electricity Policy Group, identifies that operating reserves are often only held at a minimum level, and that system reliability can be improved if more reserves are available at different prices.[124]

An ORDC would increase the reliability of the electricity system and enable it to adapt to integrate more intermittent resources effectively. Importantly, the ORDC would also provide an additional layer of revenue for fast-start peaking resources, which would assist with ensuring that there is sufficient incentive for flexible resources to be developed.

124 Hogan, Electricity scarcity pricing through operating reserves: An ERCOT window of opportunity, 2012

Operating Reserve Demand Curve	Impact	
Improves capacity assurance	Positive	• Enables improved reserve cover to meet peak needs
Improves energy assurance	Neutral	• Enables greater peak cover which could provide energy when not needed for reserves
Maintains energy affordability	Neutral	• Likely to be some cost but would be a cost efficient way to provide more reserves to meet evolving system needs
Maintains market competition	Somewhat positive	• Is a market-based mechanism that complements the energy-only market
Minimises intervention	Somewhat positive	• Ensures capacity investments are still driven by the market
Can be unwound	Neutral	• Can be unwound if it proves to be of low value

Strongly recommended for further investigation
Assess 30-minute reserve service

Assists with: Ensuring enough medium-start capacity to balance intermittency, including demand response

Another mechanism to balance intermittency is a longer notice reserve service. In Texas' ERCOT market there is a 30-minute reserve product for medium-start capacity that can be started or interrupted within 30 minutes. It is designed primarily to cover net load (load minus wind minus solar) forecasting errors.[125] As outlined already, there will be a requirement for much more sophisticated forecasting in future with increased levels of intermittent weather dependent generation. However, even with improved forecasting, there are still likely to be errors as it is impossible to perfectly predict weather.

A 30-minute reserve product would reduce the risk of forecasting errors and will also enable an important value stream for generation or load that takes slightly longer to respond. This is particularly important for demand response, as some industrial processes like aluminium production cannot be dialled up and down in seconds. Providing improved notice for these resources to schedule response will enable improved demand-side participation in markets.

Another positive aspect of this market is that it would increase the revenue signal for peaking capacity, which will further incentivise peak resources.

30-minute reserve service	Impact	
Improves capacity assurance	Somewhat positive	• Enables improved information for market participants to hedge and invest
Improves energy assurance	Somewhat positive	• Enables improved information for market participants to hedge and invest
Maintains energy affordability	Neutral	• Likely to be some cost to comply with requirements
Maintains market competition	Somewhat positive	• Increased liquidity may encourage new market entrants
Minimises intervention	Somewhat negative	• Will require rules to require information disclosure
Can be unwound	Somewhat positive	• Can be unwound if it proves to be of low value

125 Argonne National Laboratory, Survey of U.S. ancillary services market, 2016

Recommended for further consideration

Introduce a day-ahead reserve market

Assists with: Supporting unit commitment for slow-start thermal through the transition

A day-ahead market is a voluntary, financially binding forward electricity market in which buyers and sellers bid to trade volumes of electricity for the following day. While actual energy supply and demand is handled by a separate balancing market, the forward market allows users to bid to supply the following day's generation in advance. These bids can be settled either through the supply of generation or through financial settlements. Day-ahead markets are present in most European and North American markets, the merits and drawbacks of which are outlined below.[126]

Advantages of day-ahead markets

- Allows generators to schedule slower-start units better to meet forecast demand.
- Increases system reliability by providing sufficient notice for plants to be scheduled.
- Provides market signals to demand-side management providers, encouraging greater participation.
- Reduces the impact of uncertainty in real-time market prices, because a smaller proportion of generation is exposed to real-time price volatility.
- Allows market-based redistribution of risk.

Disadvantages of day-ahead markets

- Pre-dispatch already telegraphs expected market outcomes, therefore any scheduling improvement may be limited.
- If the proportion of fast-start generation increases, the market signals for slower-start generation may not be needed.
- The implementation cost for the new market may be significant.
- The day-ahead market still requires a real-time balancing market.
- The new market will not be needed if the real- time market has minimal volatility.

The benefits of a day-ahead market in New Zealand may be limited because:

- The system operator already provides updated forecasts one day ahead of demand.
- The extent to which the day-ahead market can provide clearer price signals will be increasingly limited as intermittent renewables increase the unpredictability of residual load requirements.

As such the introduction of a day-ahead product would be better to focus specifically on day-ahead reserves, which could provide a more targeted mechanism to pre-schedule slow-start thermals one day in advance, but without requiring the entire system to shift to a day-ahead market.

We believe this option is worth further consideration but, on the balance of evidence, consider it may be difficult to implement effectively.

126 Australian Energy Council, Day ahead markets: A new hope or a phantom menace, 2017

Day-ahead market	Impact	
Improves capacity assurance	Neutral	• Limited impact on capacity investments expected
Improves energy assurance	Somewhat positive	• Day-ahead market may increase predictability of energy contributions a day ahead, and provide clearer signals to slow-start generation; impact likely limited • Residual load requirement will remain unpredictable due to renewables intermittency reducing assurance
Maintains energy affordability	Somewhat negative	• May reduce ability to centrally manage dispatch for optimal price outcomes however impact on affordability expected to be limited
Maintains market competition	Neutral	• Limited impact anticipated
Minimises intervention	Somewhat negative	• Requires development of new market interface however principles of existing wholesale market are maintained
Can be unwound	Negative	• Challenging to unwind market once implemented

Recommended for further consideration

Develop a limited dispatch mandate

Assists with: Supporting unit commitment for slow-start thermal through the transition

A more volatile wholesale market is likely to increase the frequency of events where a generator (particularly those with long ramp up times) is not adequately incentivised to dispatch, despite electricity being required. For example, there is a cost to ramp up slow-start thermal assets, and these assets need to operate for a sufficient period of time at sufficient prices to recoup this cost.

Under these situations, the system operator could direct the asset to dispatch and compensate them accordingly. A mechanism could be established to provide the system operator with a limited number of calls per year of slow-start thermal to come online for a short period of time (a situation that may otherwise be uneconomic for the generator) to ensure system capacity. This could be achieved by providing a small payment pool to the system operator that is levied against electricity consumers.

It is important to note that, if applied, this is likely to only be a transitory mechanism for the 2020s to ensure that slow-start thermal units can provide capacity when needed through the transition to 2030. As more economic forms of fast-start storage and demand response come online in the late 2020s and 2030s, the need for such a mechanism is unlikely.

This intervention employs existing market mechanisms and is a relatively direct measure to influence energy assurance. If highly targeted - for example, by providing up to 10 calls per year from the system operator - it could also be quite a pragmatic and low-cost solution to addressing potential future slow-start thermal unit commitment issues in a highly renewable electricity system.

However, there is a risk that this mechanism could create perverse incentives for generators to underbid their capacity into the wholesale market to receive compensation once directed to generate. We recommend that this intervention is further considered if it is confined to a limited and highly targeted use.

Dispatch mandate	Impact	
Improves capacity assurance	Positive	• This measure would ensure that capacity from slow-start thermal can be called a limited number of times per year
Improves energy assurance	Neutral	• This measure should not be designed for prolonged energy supply
Maintains energy affordability	Somewhat negative	• Risk of market inefficiencies that prevent more economic technologies being built • Risk of perverse incentives for generators not to bid into the wholesale market • Targeted application via existing processes should minimise cost of management
Maintains market competition	Somewhat negative	• Risk of market inefficiencies that prevent more economic technologies being built • Risk of perverse incentives for generators not to bid into the wholesale market
Minimises intervention	Somewhat negative	• Centrally directive however minimal additional regulatory oversight required
Can be unwound	Positive	• Relatively easy to discontinue with some risk of having set a market precedent

For consideration

Introduce a retailer obligation

A retailer obligation usually involves a central entity (i.e., the system operator) forecasting demand for capacity in the future and then obligating retailers to write a certain amount of capacity certificates based on their anticipated load. Retailers buy certificates from producers through auctions or intra-group trade with the price of the certificates (capacity) set by the market. An example of this is Australia's Retailer Reliability Obligation.

Australia's Retailer Reliability Obligation[127]

Australia's Retailer Reliability Obligation (RRO) is a targeted example of a retailer capacity obligation. Under this scheme:

- The Australian Energy Market Operator (AEMO) identifies potential reliability gaps in each NEM region in the coming 5 years using its Electricity Statement of Opportunities. If AEMO identifies a material gap 3 years and 3 months out, it will apply to the regulator to trigger the RRO.
- When this occurs, liable entities are on notice to enter sufficient qualifying contracts to cover their share of a one-in-two-year peak demand. A Market Liquidity Obligation placed on generators ensures there are contracts available to smaller market customers by requiring certain generators in each region to make contracts available to the market.
- If AEMO is required to procure additional resources to address the shortfall in capacity, entities whose share of load is not covered by qualifying contracts will be required to pay a portion of the costs for the Procurer of Last Resort, up to an individual maximum of $100 million.

A retailer obligation would provide capacity assurance, and, depending on the structure of the obligation and penalties, could encourage retailers to diversify their 'capacity certificates' to cover a range of events (i.e., both peak capacity and dry year events). If implemented similarly to the Australian scheme outlined above, government intervention can be minimised, leaving market participants to determine optimal arrangements and technology solutions.

This obligation, however, could become complex to administer, particularly if reconciling capacity and certificates across inter-temporal periods – for example, when comparing a high capacity but shallow

127 Australia Government Department of the Environment and Energy, Retailer reliability obligation factsheet, 2019

storage solution against a low capacity but deep storage solution (e.g., a 400 MW/400 MWh lithium-ion battery vs a 100 MW/100 GWh pumped hydro storage system).

If it becomes apparent that a deepened contract market and other recommended actions are insufficient to support capacity, a retailer obligation would be the one of the most logical next steps to support capacity.

The assessment below assumes a scheme that focuses on specific capacity obligations. We recommend that a retailer obligation be one of the interventions considered to support capacity as the market transitions.

Retailer obligation	Impact	
Improves capacity assurance	Positive	• Depending on scheme, retailers can be adequately incentivised to cover both dry year and peak demand capacity requirements
Improves energy assurance	Somewhat positive	• Depending on scheme and extent of penalties for curtailment, retailers may be incentivised to ensure energy is provided when required
Maintains energy affordability	Somewhat negative	• Market-led pricing solutions drive competition to reduce costs, potential increase in market liquidity may create opportunities for new entrants • Some risk of over-procurement if system operator over-forecasts requirement • Some administrative burden will increase costs
Maintains market competition	Neutral	• Limited impact on competition expected
Minimises intervention	Negative	• Complex market to administer if looking to reconcile capacity and certificates, particularly intertemporally • The scheme could be potentially deployed in targeted areas or applications only
Can be unwound	Somewhat negative	• Extent to which reserve can be unwound is limited by length of contracts; adequate signals would need to be provided to the market to compensate

Not recommended

Secure strategic reserves

Strategic reserves refer to the central procurement of generation capacity that can only be deployed at the discretion of the central body; it cannot participate in the wholesale market. Here we outline 2 forms of strategic reserves: contracted contingency reserves and reserve portfolios. The primary difference between these forms is the style of procurement.

Contingency reserves are where a central body contracts with generators (or flexible demand) to provide reserve capacity. Today, Transpower manages a contingency reserves market to provide a safety net against unexpected events. The amount of reserve is calculated based on "N-1" – this means that the system is planned such that, for any one credible event (for example, one unit of the North-South Island HVDC interconnector going down, or one unit of a peaking plant becoming out of service) the system has sufficient contingency. The system operator compensates providers of reserves for the revenue they would have otherwise received from the wholesale market. Increasing the 'safety net' provided by contingency reserves would be one way to improve energy and capacity assurance using existing regulatory mechanisms, or a new reserve scheme could be developed.

New Zealand's 2004-2010 Reserve Energy Scheme

New Zealand's Electricity Commission operated a reserve market from 2004-2012. The Commission was responsible for managing the electricity sector so that electricity demand could be met in a 1-in-60 dry year without national power conservation campaigns. It attempted this by contracting generators to provide dry year reserve generation capacity and fuel.

The scheme was discontinued in 2010. The 2009 Electricity Market Review found the scheme had several perverse effects and probably did not improve overall security of supply. Concerns were that the scheme:

Reduced the incentive for market participants to manage their own risks (because the Commission is expected to manage those risks as a last resort).

Reduced the incentive for investment in peaker plants and for demand-side responses (because Whirinaki's fixed costs are recovered by a levy on all consumers).

Incentivised lobbying to change the rules relating to reserve energy (e.g., on dispatch of Whirinaki and to contract for additional reserve capacity), creating uncertainty.

A reserve portfolio refers to government specifically underwriting the continued operation of a portfolio of reserve assets. Traditionally, this has referred to a central body owning or at least underwriting the continued operation of thermal generation assets that would otherwise have exited the market. This is the approach taken by Belgium and Germany today and one option raised by MBIE in their Accelerating Renewable Electricity Generation and Infrastructure discussion paper.[128] This mechanism could also apply to government ownership of new assets or non-thermal assets.

Belgium's Strategic Reserve Program[129]

Belgium set up a strategic reserve program in 2014 to provide coverage for electricity during winter. The program aimed to provide electricity security while power stations were shutting across the country. It was distinct from existing balancing reserves used to cover sudden shocks or residual imbalances. The program was designed and administered by Belgium's system operator, Elia.

Procured reserves fell into one of 2 categories:

- Generation reserves (SGRs) coming from generators
- Demand reserve (SDRs) came from flexible demand resources

SGRs were only allowed from generators that had already shut down or signalled their intention to cease activities, to minimise interference of the reserve with the electricity market. The reserve program covers expenses to keep the capacity/flexibility available, as well as the cost of generation as needed.

In 2021, the European Commission approved the replacement of the strategic reserve with a capacity mechanism which would not be limited to capacity providers who were set to close their facilities.

128 Ministry of Business, innovation and Employment, Accelerating renewable electricity generation and infrastructure, 2019
129 Elia, The strategic reserves – a mechanism to cover structural shortages, 2019

Strategic reserves can be designed so they do not undermine private investment incentives – however, it is difficult to achieve in practice. In reality, private companies are likely to consider the strategic reserve when making investment decisions for new capacity, therefore reducing their propensity to invest. This was one of the reasons New Zealand discontinued its reserve energy scheme in 2010. Implementing a strategic reserve with appropriate penalties for market participants when the reserve is activated may help resolve this. However, on the balance of evidence, we do not recommend a strategic reserve given the previous issues in New Zealand.

Strategic Reserves	Impact	
Improves capacity assurance	Somewhat positive	• Capacity is reserved for deployment at system operator discretion, however risk that market participants underinvest as a result
Improves energy assurance	Positive	• System operator can deploy reserve as necessary (however for efficiency may require that reserve is fast-start capacity only, precluding CCGT)
Maintains energy affordability	Negative	• Moderate cost associated with securing reserve
Maintains market competition	Somewhat negative	• Reduces incentives for market participants to invest in capacity for risk mitigation
Minimises intervention	Very Negative	• Targeted new market required, along with new powers for system operator
Can be unwound	Somewhat negative	• Extent to which reserve can be unwound is limited by length of reserve contracts; adequate signals would need to be provided to the market to compensate

Not recommended

Consolidate thermal assets

The mooted consolidation of thermal assets would involve combining all thermal assets into a single entity, 'ThermalCo'. This entity would operate under the mandate to provide risk management products to cover peaking and dry year needs. This model may deliver operational efficiencies and better manage long-term reduction in thermal generation through central operation. It would also allow for more efficient procurement of fuel resources (i.e., natural gas). By reducing the extent to which these assets down-bid one another, market prices could more accurately reflect total operating costs and reduce 'missing money' issues for thermal generation. However, ThermalCo raises some prospective concerns:

- **Solution for existing thermal capacity only:** Capacity mechanisms may still be required to attract investment in other firming technologies as thermal energy is phased out.

- **Competitive risks:** ThermalCo and any legislated protections it receives to be economically viable for owners may create competitive issues that reduce new market entrants and ultimately slow investment in low-emissions alternatives.
- **Requires sector coordination to execute:** ThermalCo would require significant coordination and alignment between competing generation companies to execute.
- **Limitations in incremental value:** The sale of 'insurance' in the form of risk management products can be executed by the market in its current form, without a solution such as ThermalCo.
- **Shareholder response:** Without some government underwriting or advantageous market rules, there would be considerable risk attached to a thermal-only generation company, and shareholders may take issue with other generators divesting responsibility for high emissions assets. The attempted de-merger of thermal assets by AGL in Australia and resulting backlash presents a case study of the risks of this approach.[130]

For these reasons, we do not recommend ThermalCo as an intervention.

Consolidate thermal assets	Impact	
Improves capacity assurance	Somewhat positive	• Maintenance of existing capacity may be improved however ThermalCo operator may be under no obligation to maintain this capacity
Improves energy assurance	Somewhat positive	• Ability for centralised thermal operator to manage bids into the market for peaking load may be more straightforward vs competition across multiple assets
Maintains energy affordability	Somewhat negative	• Operational benefits of maintaining thermal assets together • However, potentially higher costs as due to lack of bid competition
Maintains market competition	Highly negative	• Centralisation of thermal assets reduces competitiveness • Risk that presence of ThermalCo and supporting regulatory environment disincentivises other potential new entrants
Minimises intervention	Very negative	• Without significant government intervention ThermalCo is unlikely; furthermore, significant regulatory oversight would be required to limit market power issues
Can be unwound	Highly negative	• Consolidation of thermal assets into a single portfolio would be difficult to unwind without then again breaking up the assets, likely at further loss of value

130 The Guardian, AGL dumps demerger plan, yielding to Mike Cannon-Brookes, 2022

Not recommended

Introduce a capacity market

A capacity market runs alongside the energy market. While energy markets compensate assets for the electricity they generate, a capacity market compensates assets for being available to generate. The basic premise of a capacity market is to provide an additional revenue stream to assets that may only infrequently generate electricity (often sufficient to partially or fully cover fixed costs), thereby reducing the perceived risk to revenues. As capacity markets present an additional revenue stream for generators, the energy market typically sees supressed price spikes.

Capacity markets are common, particularly in parts of the US and Europe. Because the level of built capacity is controlled by the central buyer (typically the regulator or market operator) capacity markets provide high capacity assurance. However, capacity markets bring challenges as highlighted by Concept Consulting in their 2020 report, ***Capacity Markets and Energy-only Markets: A Survey of Recent Developments***.[131]

These challenges are:

- Price signals for assets to generate when required are weaker than in an energy only market, potentially eroding assurance of energy supply.
- Capacity markets are prone to over-procurement leading to higher costs. Western Australia's capacity market caused an estimated 23% overbuild in 2016-17 representing a $116 million incremental cost per year.
- Considering New Zealand's intertemporal capacity requirements (i.e., short duration peak capacity and inter-year energy), a New Zealand capacity market would need to factor different types of capacities to meet both peaking and dry year needs, adding complexity. This would make it difficult to, for example, have a central agency compare the relative value of a high capacity, but shallow storage solution against a low capacity but deep storage solution (e.g., a 400 MW/400 MWh lithium-ion battery vs a 100 MW/100 GWh pumped hydro storage system).
- Central decision-making and prescription may erode innovation within the sector and weaken incentives to select the most cost-effective mix of supply/demand response options.

Because of the significant government intervention required to set up a capacity market, and concerns around their effectiveness in providing both capacity and energy assurance, we do not recommend a capacity market as one of the core interventions for consideration by government.

131 Concept Consulting, Capacity markets and energy-only markets – a survey of recent development, 2020

Capacity markets	Impact	
Improves capacity assurance	Positive	• High capacity assurance as dictated by regulator/system operator but may not always be the right amount or type of capacity
Improves energy assurance	Neutral to worsened	• Capacity assurance contributes to energy assurance (without required capacity, zero assurance of energy) • Wholesale energy price signals weakened by capacity payments
Maintains energy affordability	Negative	• Bias toward over-procurement • Additional costs for set up
Maintains market competition	Somewhat negative	• Reduces market innovation • Potential for market to prop up otherwise unviable existing assets rather than introducing better technologies
Minimises intervention	Highly negative	• New market required • New mandate for regulation required • Capacity markets must be set and adjusted centrally
Can be unwound	Negative	• A transitionary capacity market would be difficult to administer, as its limited longevity would inflate capacity bids

Not recommended
Introduce government incentives

Another option to encourage energy capacity is to directly incentivise new capacity, or the maintenance of existing capacity. Incentives could be highly targeted to existing players or upcoming projects, be awarded on an auction or application basis, or target specific types of capacity (i.e., to invest in more fast-start or to maintain existing slow-start).

An example of a direct government incentive is the Australian UNGI program. Legislated in 2021 by the government at the time, the Underwriting New Generation Investments (UNGI) program is an interim measure intended to reduce entry barriers for new firm generation in the medium-term by underwriting them. However, the program faced scrutiny over its 'technology agnostic approach' which was criticised for supporting fossil fuels without factoring in the long-term climate costs.

A direct incentive, rather than a capacity market, would be intended as a limited program to spur an initial or short period of investment, rather than being an ongoing contribution or market. Once the required capacity is built, the direct incentive would cease. However, there are several difficulties with these incentives:

- While the incentives can be wound back it creates an ongoing threat of potential future intervention, which can crowd out investment in future capacity
- The government needs to 'pick winners' to select the right type of capacity at the right price. Given the evolving nature of different flexibility solutions and needs (short, mid, and long-term duration), it can be difficult to compare relative economics of different types of flexibility
- The government needs to stipulate a level of required capacity, which can often be inefficient

Due to the potential for this intervention to create distortions, we do not recommend them for consideration.

While we do not recommend direct government incentives, we do support innovation funding (e.g., through organisations such as Ara Ake) and green investment financing (e.g., through Green Investment Finance). These mechanisms can assist with deployment of early-stage technologies and solutions to meet capacity and energy needs. In many instances, this can assist with proof of deployment for technologies and can 'crowd in' necessary private sector investment.

Direct incentives	Impact	
Improves capacity assurance	Positive	• Can directly prescribe level and type of capacity introduced but may have long-term impacts
Improves energy assurance	Somewhat positive	• Assurance depends on level of commitment required from participants, and extent to which incentives are targeted at capacity that can provide energy when required
Maintains energy affordability	Negative	• High potential to create distortions in the wholesale electricity market • Risk of incorrect central decisions encouraging investment in the wrong assets
Maintains market competition	Somewhat negative	• Risk that resultant distortions in the wholesale electricity market lessen competition (depending on form of incentive)
Minimises intervention	Negative	• High intervention required from government
Can be unwound	S	• An incentive program can be ceased with little effort or timebound • While in theory the mechanism can be unwound, the future threat of its re-implementation can stifle subsequent investment

Recommendation theme 3: Scale transmission and distribution network investment

In all pathways there is a clear need for a significant scaling up of transmission and distribution infrastructure investment to at least $30 billion in the 2020s. The investment in transmission is predominantly to enable renewable generation but will also accommodate increasing electrification. As the transmission system moves from connecting large, centralised power stations to more distributed, large-scale renewables, infrastructure will need to evolve.

The investment in distribution infrastructure is predominantly to enable increased electrification but will also be required to accommodate distributed generation and multi-directional power flows. Section 6.4, Fundamental Question 3 outlined the clear preference for investment to occur ahead-of-time to avoid delaying decarbonisation and increasing net power prices.

This section focuses on physical infrastructure. Virtual infrastructure (e.g., virtual network assets like demand-side flexibility) will also need to significantly scale and is outlined in Section 8.4.

We recommend 3 actions to scale transmission and distribution investment:

f. Accelerate transmission development to enable renewable generation (high priority)

g. Scale distribution investment to enable electrification (high priority)

h. Consider options for renewable energy zones

f. Accelerate transmission development to enable renewable generation (high priority)

Minimise the risk of network investment timing constraining renewables growth

Globally, several transmission networks have struggled to keep pace with significant increases in renewable energy deployment. This has led to transmission grid constraints, which have stalled the energy transition. [132] While New Zealand is yet to experience this significant increase in renewable energy in our networks, our modelling, the whole-of-sector view analysis, public announcements, and Transpower's enquiries pipeline data illustrate that a large increase in renewable deployment is inevitable in the 2020s and 2030s.

In simple terms, transmission networks have delayed the energy transition in other countries for 2 main reasons (see Exhibit 95):

1. Transmission companies and regulators often predict that transmission projects are required later than they are needed
2. It often takes transmission companies longer to deliver the transmission projects than originally planned due to regulatory approval, consenting, and supply chain delays

Exhibit 95: **Simplified, illustrative axample of how transmission has been delivered too late in other jurisdictions**

Transpower's Net Zero Grid Pathways program has identified the key transmission projects that need to be developed by 2035. Two themes may put these timelines at risk: prolonged consenting processes, and protracted approvals processes.

Two actions to address this are:

1. Ensure that enabling consenting elements for renewables are equally reflected in consenting elements for networks

Transpower has identified that "currently, consenting and land access timeframes for large projects can be in the order of 3–7 years before the 2–3 years of build

132 Recharge News, Transmission issues to delay renewable power's supremacy in Australia - Rystad, 2021

can be commenced".[133] Consenting timelines going forward need to be faster for transmission projects to be developed in a timely manner. This report has already discussed the need for significant updates to the RMA that reduce timelines for consenting of renewable generation; this need applies equally to networks as it does generation assets.

As outlined, to improve the consenting environment for renewable generation, the National Policy Statement for Renewable Energy Generation needs to be improved to give greater weight to the enabling rather than prohibitive elements of consenting. Similarly, the National Policy Statement for Electricity Transmission would need to be commensurately upgraded with the same enabling aspects as the National Policy Statement for Renewable Energy Generation. It is recommended that RMA reform addresses the inadequacies of the RMA processes that lead to lengthy consent processing.

2. Streamline approval processes to accelerate the delivery of networks

As articulated by Transpower in their 2021 submission to the CCC:

"To increase our pace of delivery, we will need to make decisions and commit to investments in circumstances where, in the last 2 decades, we might have waited for better information…This implies shifting the framework [under which network investment decisions are made] to:

- *Investing in network capability*
- *Creating options for further electrification and renewable generation*
- *Having frameworks in place to proactively make decisions where inaction due to uncertainty is an unacceptable outcome"*[134]

This is essentially proposing that the investment framework needs to be considered more on a probabilistic, ahead-of-time basis, rather than a deterministic, just-in-time basis. We agree with this in an environment of increased uncertainty as outlined in Section 6, Fundamental Question 3.

Specifically, we recommend that policy:

- Codifies the shift from a deterministic, just-in-time investment framework to a probabilistic, ahead-of-time investment framework.
- Considers a mechanism to fast-track investments early in the Commerce Commission approval process when the benefits far outweigh the costs on a probabilistic basis.
- Enables the Commerce Commission to have greater consideration of the benefits of decarbonisation in its investment tests.

133 Transpower, Submission to the Climate Change Commission on the Commission's first emissions budget and advice to the Government, 2021

134 Transpower, Submission to the Climate Change Commission on the Commission's first emissions budget and advice to the Government, 2021

g. Scale distribution investment to enable electrification (high priority)

This roadmap identifies that $22 billion is required in distribution sector investment in the 2020s to enable electrification and integrate distributed energy resources. This represents a 30% increase in total expenditure (TOTEX) in 2026–30 relative to 2021–25 and a significant increase in growth CAPEX. Transpower has identified that "Transpower and distribution lines companies must directly support and enable rapid electrification. If one part of the supply chain is not prepared with either the equipment, expertise or planning, the electrification of our economy will stumble at the start."[135] We agree with this sentiment and have identified that distribution spend will need to increase significantly to enable this electrification.

It is also likely that unforeseen additional investment may arise within regulatory periods and the regulatory framework needs to be able to adjust for this in a timely manner.

There are a number of ways that the increased need for distribution investment and flexibility can be achieved:

- **Alter the network investment framework approach:** Similar to the need on transmission networks the investment framework will need to adjust to one that is made more on a probabilistic, ahead-of-time basis, rather than a deterministic, just-in-time basis. This change in paradigm for network investment could lead to improved enablement of electrification in the second half of the 2020s.
- **Enable the Commerce Commission to consider emissions reductions in regulating EDBs**: This would increase the likelihood of funding being approved for network investment that enables electrification.
- **Evaluate mechanisms for EDBs to amend plans within a regulatory period**: Due to rapid electrification, distribution networks will require timely funding flexibility mechanisms. To achieve this, the new re-opener for unforeseen CAPEX requirements, and guidelines around contingent projects, should be reviewed to ensure they accommodate the increasing likelihood for network requirements.

135 Transpower, Transpower electrification roadmap, 2021
136 Transpower, Renewable energy zones, 2022

h. Consider options for renewable energy zones

Renewable energy zones (REZs) are one mechanism to align transmission investment with development appetite for renewables in highly resourced but insufficiently connected regions. In Australia, REZs are currently under development. For example, New South Wales' first REZ in Central-West and Orana saw Expressions of Interest equivalent to 27 GW compared to the planned 3 GW zone. Similar approaches in New Zealand may help align transmission and generation investment. Transpower has already consulted on a potential REZ pilot in Northland, although the project remains a concept at this stage.

In 2021, Transpower identified that, out of 11 GW of wind and solar generation that investors may consider building in the next 30 years, around 6 GW could be built under current market arrangements and regulatory processes for developing new transmission. The remaining 5 GW was in regions where high connection costs or the first-mover disadvantage could inhibit investment under current processes and regulatory frameworks.[136] These areas were mostly identified in regional parts of the country that are joined to the grid via connection, rather than interconnection assets.

To ensure there is enough transmission to connect all the required renewable generation by 2050, the sector will need a mechanism to easily enable regional transmission development. Renewable energy zones are a potential solution.

Recommendation theme 4: Enable a smart electricity system

A smarter, more flexible electricity system will save ~$10 billion on an NPV basis to 2050. Our roadmap highlights the need for 2 GW of demand flexibility in 2030 and 5.8 GW of demand flexibility in 2050. As electrification and the level of intermittency increases on the system, networks and power flows will become increasingly complex and multi-directional, and demand-side and storage flexibility will become much more valuable. To deliver this, the electricity system will need to become much smarter.

The electricity system of the future will be able optimise millions of energy resources and appliances in real-time by leveraging smart system enablers like full network visibility (down to the household), automation, AI, Internet of Things, smart communications, and platforms. However, as we transition to this state, which could take at least 2 decades, it is important to consider how markets, regulations, policies and standards will need to evolve.

These smart system enablers will emerge in networks this decade, but until then, networks and operators may need to rely on more manual, targeted means of accessing network flexibility in the 2020s. With increasing peak electricity demand putting pressure on the system's physical infrastructure, flexibility will be important. It may delay the need for infrastructure development and reduce costs for consumers.

Additionally, retailers will also need to increasingly use demand-side and storage flexibility to hedge their customer books to meet peak demand. In some instances, this will be a risk management tool for retailers. In other instances, it will be a revenue opportunity as retailers who face the underlying time-of-use price of electricity can use flexibility to arbitrage against the flatter pricing profiles they offer.

To transition to a smarter electricity system, we recommend 5 actions:

i. Improve distribution peak pricing signals and smart managed tariffs (high priority)

j. Establish a framework for the formation of competitive flexibility markets (high priority)

k. Update regulatory frameworks to support virtual network investment, including implementing total expenditure (TOTEX) funding (high priority)

l. Mandate default off-peak electric vehicle charging (high priority)

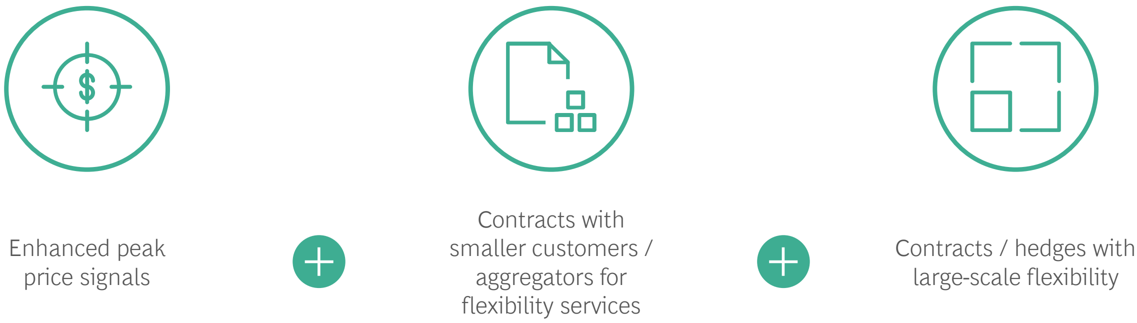
m. Enable network investment in key aspects of orchestration, including visibility and operations

We have provided a number of potential solutions to enabling flexibility as we believe it is important to provide optionality while flexibility markets are still nascent. As the smart capabilities of the system develop and new markets for flexibility emerge, it will become clearer which solutions are more preferable, and how policy, markets and regulation can evolve to support these. The main solutions for enabling flexibility in networks are outlined in Exhibit 96 below.

Exhibit 96: **Several solutions needed to enable a smart electricity system and ensure consumers and networks can benefit from flexibility**

For flexibility accessed by retailers, we expect increasing sophistication will be required across retail pricing, contracting for flexibility, and hedges with flexibility providers. These options for retailers accessing flexibility are outlined in Exhibit 97.

Exhibit 97: **Several solutions needed to enable a smart electricity system and ensure consumers and retailers can benefit from flexibility**



i. Improve distribution peak pricing signals and smart managed tariffs (high priority)

Distribution pricing signals

Pricing is critical for providing the right incentives for market participants and consumers to optimise their flexible assets to manage peaks. Today, many distribution companies have tariffs that promote peak vs off-peak shifting, although this can be improved and more targeted. A shift to time-of-use-pricing with greater differences between off-peak and peak periods will provide clearer price signals for the use of network capacity. Pricing distribution capacity in line with costs is desirable as it is efficient for those who benefit from distribution investment to pay for it.

As peak demand increases due to electrification, this will put pressure on physical network infrastructure. Clearer pricing signals will promote efficient use of the network during peak periods, ameliorating the infrastructure needed, and easing the transition.

With increased peak prices, off-peak periods (e.g., midnight to 6am) can be priced lower. This will incentivise more efficient demand shifting of technologies that can achieve this (e.g., batteries and electric vehicles).

In time, we expect more time-of-use-pricing to emerge in retail, which will enable the price signal from distributors to be passed more effectively to the end consumer.

Efficient pricing should provide much of the required incentive for retailers and consumers to optimise their use of the distribution network and promote flexibility in distribution networks.

Load control tariffs

Despite pricing sending a strong signal for retailers and consumers, there are times when inefficiencies or frictions result in the desired demand response not being provided. In some instances, consumers have flat retail tariffs or are not actively engaged in managing their energy demand.

Load control tariffs are an efficient way for networks to provide pricing signals coupled with smart control to ensure large-scale, dynamic demand response. Today, load control tariffs are used for hot water ripple control and are the most important demand management tool in the electricity system.[137] It is estimated that around 50% of customers have ripple control, equating to roughly 15% of New Zealand's peak demand.

EECA estimates that the total annual cost of providing ripple control ranges between $10 and $27 per kW of controllable load compared to $130 per kW per year to provide additional peak distribution capacity, making this virtual network solution 80-90% lower cost than a physical network solution.

Consumers also benefit from this. Consumers on a night-only tariff will have their water heated between 11pm and 7am and often pay a reduced rate for electricity in return for allowing network companies to manage their hot water systems.

In the 2030s, we predict that electric vehicles will overtake hot water ripple control as the largest demand-side flexibility opportunity. By 2050, we predict electric vehicle demand-side flexibility will be 3 times greater than hot water ripple control. As such we believe it is critical that effective EV load control tariffs emerge quickly to enable networks to efficiently manage peak demand and to avoid or defer physical network build.

The Electricity Authority has stated that it "considers separate load control tariffs to be an appropriate and cost-reflective way to approach mass EV charging and hot water heating, consistent with the distribution pricing principles". We agree with this sentiment and consider load control tariffs to be an effective tool for managing appliance-specific demand-side flexibility at scale.

j. Establish a framework to form competitive flexibility markets (high priority)

Improved distribution pricing is an effective mechanism for signalling the need for flexibility, while load control tariffs are an effective way for distributors to contract and directly access flexibility. Improving these 2 elements will be critical to ensuring distributors can more effectively manage peak demand and save $6 billion in avoided or deferred physical infrastructure on an NPV basis by 2050.

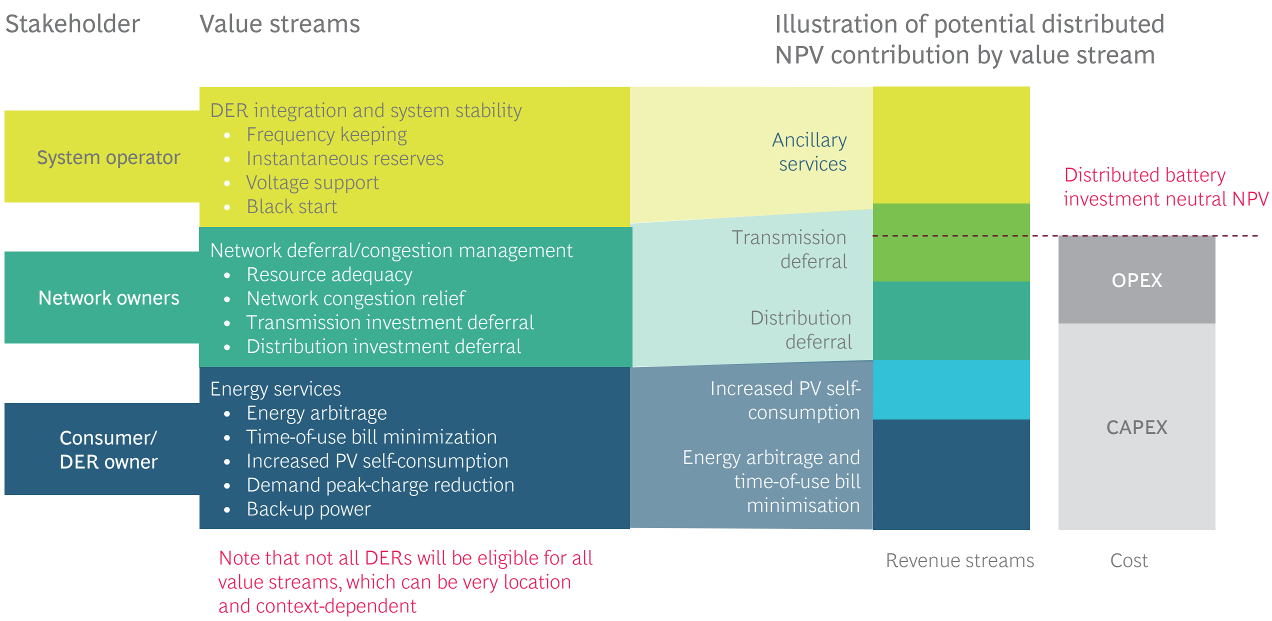
However, there is also an opportunity for contracted flexibility response that pays flexibility providers (e.g., customers, retailers, aggregators, virtual power plant providers etc.) for services they provide to flexibility buyers (e.g., distributors, retailers, the grid owner, and the system operator). Because a flexible resource like a battery or an EV can provide valuable services to more than one buyer (e.g., to provide peak response for retailers or peak response for distribution networks), it is important to consider how markets and system coordination can evolve to ensure that a resource is not locked out to one flexibility buyer and value stream. Enabling resources to participate across more than one value stream will ensure that flexibility

137 Energy Efficiency & Conservation Authority, Ripple Control of Hot Water in New Zealand, 2020

suppliers can maximise the value of their resources and the benefits to the entire electricity system can be increased.

The concept that flexible solutions can 'value stack' or compete and be compensated for a range of flexibility services to be economically viable is illustrated below in Exhibit 98 by Transpower.[138]

Exhibit 98: Value streams differ by stakeholder



Source: Transpower

We see the opportunity for load control tariffs and contracted flexibility to work together to enable flexibility, rather than one or the other. As such, it will be critical to understand how resources that provide flexibility to distributors via load control tariffs can also provide services like peak demand response to retailers.

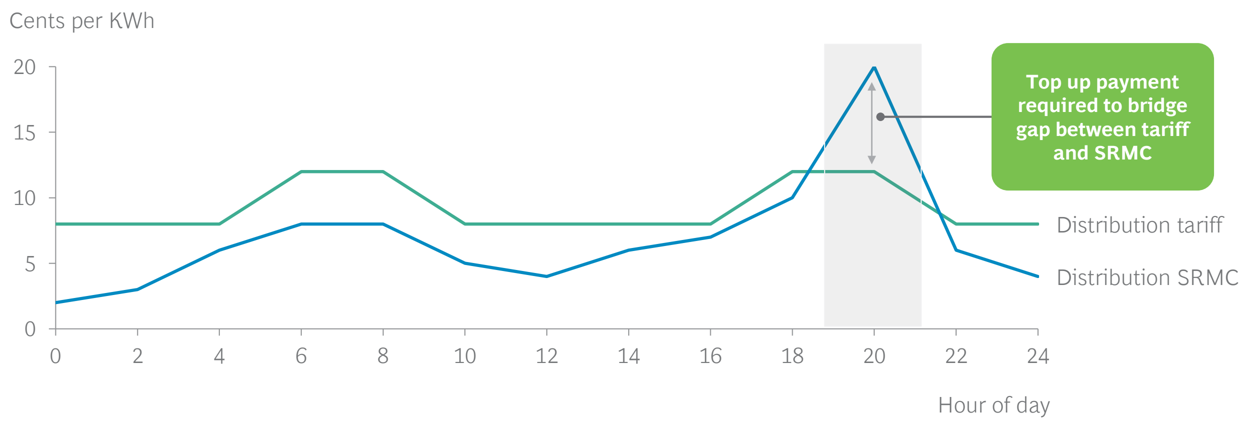
Flexibility markets will enable broader opportunities for flexibility providers to access value streams and monetise services they provide.

A distributor's requirement for flexibility services may arise because peak, shoulder, and off-peak distribution pricing is sometimes insufficient to send the right price signals to consumers – it may lack granularity to

138 Electricity Authority, Developing Flexibility Markets in New Zealand, 2021

send real-time, short-run marginal cost signals. One solution for this issue, as outlined earlier, is load control tariffs. Another option is to use flexibility payments to 'top up' payments between the peak network tariff and the real-time short-run marginal cost (SRMC) experienced by the distribution network (see Exhibit 99).

Exhibit 99: **Illustration of potential need for top up flexibility payments**



Source: International Energy Agency, BCG analysis

Top up payments can broadly be achieved by 4 different types of flexibility contracts:

- **A fixed availability payment with service level agreements:** This provides for distribution companies to call on a resource under certain conditions in line with agreed service level agreements. In this instance the resource is guaranteed to be available to the distributor within certain parameters.
- **A voluntary fixed response payment that pays for response supplied when requested:** Under this model flexibility suppliers can voluntarily choose to provide flexibility services at a pre-agreed price when services are requested.
- **A blended fixed + flexible model:** Whereby flexibility suppliers are provided with an availability payment plus a variable component when flexibility services are requested, within agreed service level agreements.
- **An hours-ahead or near real-time auction model:** Whereby flexibility services are auctioned up to an agreed quantity and pricing is dynamic based on bids received. This is the model Transpower has used, with a pay-as-bid auction, for its demand response platform.

With flexibility contracts, distributors, the grid owner, and retailers can all use these mechanisms to contract for flexibility, which enables value stacking across different revenue streams for flexibility providers.

Developing competitive flexibility markets

The UK is leading the world in flexibility markets. In the 2021/22 financial year, distributors procured 3.7 GW of flexibility resources.[139] On a pro-rated basis, this would be an impressive 500 MW of capacity in the New Zealand's electricity system – nearly 50% of the non-EV demand-side flexibility needed under our preferred pathway by 2030.

The below UK energy regulator OFGEM's 2021 Smart System's Flexibility Plan has been adapted below to provide possible initiatives that could be considered in New Zealand.[140]

Theme	Priority initiatives
Facilitating flexibility from consumers	• **Enable flexibility suppliers:** Update the Code to allow flexibility suppliers to participate in the electricity market.[141] • **Code of conduct:** Develop a code of conduct for flexibility traders to enhance consumer confidence. • **Review smart meter standards:** Ensure smart meter specifications are adaptable to future flexibility service requirements. • **Smart tariff information:** Develop a tool allowing consumers to compare smart tariffs. • **Cyber security:** Work with the electricity sector to develop cyber security standards that give consumers the confidence to engage. • **Consumer protection:** Put frameworks in place to protect consumers who participate in smart energy, support consumers to participate who might otherwise struggle to do so, and do not unduly penalise customers who cannot participate. • **Flexibility consideration in future initiatives:** Adequately consider flexibility resources in future market mechanisms. • **Opportunity sizing:** Work with the electricity sector to develop processes to size and locate value of flexibility services (i.e., work with EDBs to publish network congestion points).
Removing barriers to flexibility on the grid	• **Standards:** Work with the sector to develop a standardised technical arrangements roadmap including equipment and connection standards. • **Data requirements and access:** Set standards for, and support facilitation if needed, for data sharing across flexibility market actors (e.g., network providers, retailers, flexibility traders and metering equipment providers) aligned with MBIE's consumer data right. • **Equal access:** Ensure fairness in connection approach for distributed energy resources and storage across regulatory mediums and network operators.

139 UK Energy Networks Association, Britain breaks flexibility records for four years running – almost 4GW tendered in 12 months, 2022

140 UK Government, Smart systems and flexibility plan, 2021

141 The Code refers to the Electricity Industry Participation Code

Theme	Priority initiatives
Reforming markets to reward flexibility	• **Network charging reform:** Incentivise and allow network providers to send forward-looking price signals that reflect the value of avoided load to those that can act (likely retailers and flexibility providers rather than consumers). • **Product and procurement standardisation:** Facilitate sector-led development of standardised products and procurement processes to reduce overhead costs and reduce barriers to entry for participants across the 29 EDB geographies. This may extend to the eventual establishment of common procurement platform like OFGEM's Piclo platform. • **Right to play:** Review existing arrangements for procurement of services that could be provided by flexibility markets and ensure that eligibility of these services is included (i.e., in relevant ancillary markets).
Delivering the framework	• **Monitoring:** Develop monitoring criteria to maintain progress around the implementation of the framework and identify areas for further support.

We note that Ara Ake's FlexForum Flexibility Plan 1.0 has some of these elements.[142] Several initiatives are also being discussed by groups including the Electricity Authority Innovation Participation Advisory Group and the ENA's Network Transformation Roadmap. While strong sector engagement and collaboration is crucial, it is important that a central body drives this framework for flexibility markets and monitors its execution.

The UK has successfully developed the critical market architecture for flexibility markets, including:

- Standardised flexibility products (e.g., fast response vs slow response, short duration vs long duration, pre-contingent vs post-contingent)
- Standardised flexibility contracts
- Standardised flexibility procurement platform (Piclo)
- Standardised flexibility rules

This fundamental market architecture (products, contracts, procurement platform, and rules) has shaped the UK flexibility market and lowered transaction costs and barriers to entry for both buyers and sellers of flexibility. It has also outlined clear service level agreements that assure network owners of resource response when required. A similar exercise to develop this core market architecture needs to occur in New Zealand.

However, it is important to note that this took a while for the UK to develop. The first Smart Systems and Flexibility Plan was launched in 2017 and was developed by the UK Government and OFGEM (the regulator of gas and electricity markets) with the UK's energy sector. It set out a vision and suite of actions to drive a net zero energy system. The UK's experience demonstrates that flexibility markets take a number of years to develop and require collaboration across multiple stakeholders. It is recommended that the development of flexibility markets are significantly accelerated in New Zealand to assist with achieving the 2 GW of additional demand-side, smart system response required by 2030 in Pathway 3.

142 Ara Ake, A Flexibility Plan 1.0, 2022

k. Update regulatory frameworks to support virtual network solutions, including implementing TOTEX funding (high priority)

Supporting investment in virtual network solutions (i.e., flexibility rather than physical assets) is an issue that regulators are grappling with globally. One of the issues is that spend allowances for networks are often provided in a split of CAPEX (i.e., including physical network solutions) and OPEX (i.e., including virtual network solutions). As a result, OPEX is often used to pay for virtual network solutions in instances where this saves a greater level of CAPEX on physical infrastructure. This gives rise to 2 main issues:

- If total expenditure or TOTEX can be saved in a scenario where the OPEX allowance is exceeded, it is unlikely to occur, even if this enables greater reductions in CAPEX.
- Spending a dollar on CAPEX provides greater returns to network owners than spending a dollar on OPEX – this CAPEX bias is a known phenomenon in electricity network regulation.

The Commerce Commission's 2020–25 Default Price Pathway made some headway in addressing this issue by aligning incentives for OPEX and CAPEX savings. However, we do not consider this sufficient to incentivise large-scale shifting of CAPEX to OPEX to enable virtual network solutions.

We propose that:

- The CAPEX bias is continued to be removed. We recommend adopting a TOTEX approach as employed by OFGEM in the UK.
- Until a TOTEX approach is implemented, we recommend adjusting the base-step-trend OPEX spend assessment to include adequate forward-looking considerations, accounting for factors like increased cyber security costs and non-network solutions.

Opportunity for TOTEX-based pricing methodology

TOTEX-based regulatory pricing methodologies for network providers are relatively new but have already been deployed across multiple electricity regulatory regimes including the UK, Germany, the Netherlands, and Italy. There are 2 main considerations for regulators in adopting a TOTEX-based regime:

- Concerns around biases of network providers toward CAPEX over OPEX spend
- Changes in the technological environment, whereby less capital-intensive options are becoming increasingly available to reliably meet time-varying demands for network services

The approach involves setting TOTEX allowances to replace separate allowances for CAPEX and OPEX for EDBs. The regulator approves an overall TOTEX allowance based on benchmarking and devises an appropriate capitalisation rate (portion of TOTEX that is capitalised). Regulators often disaggregate TOTEX spend into categories for benchmarking and assessment. These categories can be more closely aligned to the individual needs of EDBs based on their existing networks, community, and geographic requirement.

Frontier Economics' 2017 case study on OFGEM's transition to a TOTEX-based pricing provides some insights about the regulator's approach.[143]

OFGEM previously employed the building blocks approach to investment regulation with separate allowances set for CAPEX and OPEX. OFGEM found that the previous system created a bias toward reducing OPEX spend over reducing CAPEX spend for the following reasons:

- Differences in incentive rates between OPEX and CAPEX savings
- Preference of companies to grow their regulated asset base (RAB) as perhaps their true cost of capital was lower than the regulatory allowance
- Perception that OFGEM would see underspent CAPEX as a sign of diminishing network reliability

In response OFGEM implemented the below changes:

- Common treatment of all costs
- Development of a capitalisation parameter to apportion spend that can be added to the regulated asset base
- Increased weight on TOTEX benchmarking vs other benchmarking parameters
- Deployment of detailed activity-based accounting guidelines to allow for the comparison of companies in a granular, disaggregated manner

TOTEX-led pricing can provide EDBs with greater freedom to make efficient OPEX-CAPEX trade-offs and to increase spend on virtual network solutions that save CAPEX for physical network infrastructure. It can also reduce focus by the regulator on second-guessing EDB's business decisions and a greater focus on setting an appropriate overall cost allowance.

143 Australian Energy Market Commission, Totex expenditure frameworks, 2017

Another important element that will assist with the delivery of virtual network solutions is innovation funding and support. The $6 million funding for recoverable cost for innovation projects in the Commerce Commission's 2020-25 Default Price Pathway has made initial progress in this area. However we believe that this level of funding needs to increase to enable the adoption of virtual network solutions.

At a glance: Supporting innovation in regulated networks

In highly regulated sectors such as electricity networks, 2 measures are often required to unlock innovation:

1. **Funding support:** 3 forms of funding can be deployed: 1) directly fund initiatives; 2) allow participants to claim a portion of innovation spend as part of their regulated cost base; 3) mandate that participants perform a certain level of innovation activity.
2. **Regulatory sandboxes:** A regulatory sandbox is a framework within which participants can test innovative concepts in the market under relaxed regulatory requirements at a smaller scale with appropriate safeguards in place. Sandboxes allow innovators to test new ideas that are only partially compatible with the existing legal and regulatory framework. They also allow regulators to learn about innovations and develop the regulatory environment to accommodate them. Electricity regulatory sandboxes have been deployed across Australia, Austria, Germany, Italy, the Netherlands, Great Britain, and the US.

- UK regulator, OFGEM, offers 3 innovation delivery vehicles for network operators: the Innovation Link, the Strategic Innovation Fund, and the Energy Company Obligation offset.
  - The Innovation Link helps organisations understand the regulatory implications of their propositions and how to adapt their approach for today's markets. It also offers a regulatory sandbox environment.
  - The Strategic Innovation Fund is a £450 million fund for network innovation from 2021-2026.
  - The Energy Company Obligations offset requires suppliers to promote initiatives such as helping vulnerable households to heat their homes.

l. Mandate default off-peak electric vehicle charging (high priority)

The roadmap to our preferred pathway requires 1 million EVs in 2030 and 4.3 million by 2050. This uptake has significant benefits for New Zealand's emissions profile but represents a sizeable incremental demand on the electricity network.

The roadmap to Pathway 2 (our preferred pathway) requires 0.5 GW of EV battery capacity flexibility in 2030, and 3.7 GW by 2050 (equivalent to roughly 3 Huntly power stations). This contribution to flexible capacity could be even higher if vehicle-to-grid technologies (V2G) emerge at scale over the coming decades. The capability to manage and coordinate this significant level of flexibility is still nascent. As outlined by EECA, "smart and energy-efficient EV charging holds the greatest potential to reduce peak electricity demand in New Zealand."[144] As EVs emerge

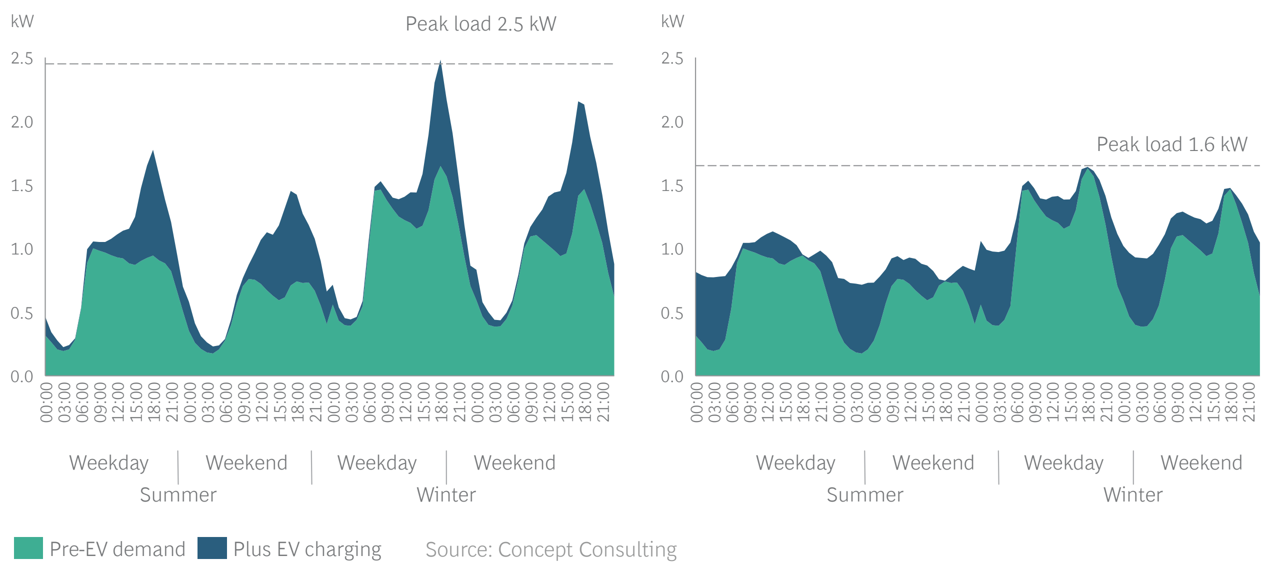
144 Energy Efficiency & Conservation Authority, Improving the performance of electric vehicle chargers, 2022

as the most dominant form of flexibility on the electricity system, it is important that policy, markets, and regulations ensure they do not contribute significantly to new peak demand growth.

The most effective way to drive EV charging away from peaks is to mandate smart chargers and to have their default setting set to charging during off-peak times. The UK Government has implemented these changes and from June 2022, new home and workplace chargers must be smart chargers that have default settings that limit their ability to function from 8am to 11am and 4pm to 10pm.[145]

We strongly recommend that similar smart charging legislation is introduced in New Zealand by 2025 to avoid EVs having a significant impact on peak demand. Smart chargers allow EV charging to be managed in a similar manner to ripple control today. Exhibit 100 demonstrates the impact of 'smart' vs 'passive' charging on the network. Modelling by Concept Consulting in 2018 estimated that EV-linked peak demand will increase to 3,000 MW by 2050 in a passive charging scenario, compared to 500 MW in a managed charging scenario. Under these scenarios, smart charging could reduce growth transmission and network costs by up to $6.1 billion to 2050.[146]

Exhibit 100: **Household demand contribution from an electric vehicle**



Source: Concept Consulting

Vector has also found that smart EV charging could improve the management of its network. As part of its EV smart charging trial, Vector found that 100 cars using a 7 kW charger could result in network load as low as 100 kW or just 1 kW per charger.[147] This is lower than the theoretical 700 kW of charging provided by 100 7 kW chargers due to diversity in charging patterns and the ability of smart chargers to optimise charging patterns.

Consumers are also unlikely to notice that their EV is being charged 'smartly'. Analysis of over 1 million home charging sessions in Texas, US, indicated that drivers typically plug their vehicle in for over 12 hours, but the actual charge time is less than 2.5 hours, providing ample opportunity to optimise time-of-charging to support the network with no impact on the consumer.[148]

145 UK Government, Complying with the Electric Vehicles (Smart Charge Points) Regulations 2021, 2022

146 Concept, Driving change – Issues and options to maximise the opportunities from large-scale electric vehicle uptake in New Zealand, 2018

147 Energy Systems Integration Group, Webinar: EV Smart Charging Trial, 2022

148 Bloomberg, Governments seek smart charging options, 2021

m. Enable network investment in key aspects of orchestration

Operating a much smarter and flexible electricity system will require more sophisticated network operations. Today, Transpower has good real-time visibility of demand and supply across the country at a high voltage level (i.e., on large transmission assets). Distribution networks also have good real-time visibility of demand and supply on some of their largest assets like zone substations, which can provide electricity to an entire suburb. However, distribution networks do not have great visibility of their network at a low voltage level, including what is occurring on streets in real-time. This is largely due to technology and costs. In the past it has made economic sense to have smart monitoring systems across the largest system assets, but it has been difficult to justify this cost down to a household and street level.

However, as the cost of smart devices and network management systems continue to decline, improving low voltage visibility is becoming more cost effective. The benefits of this visibility will also increase as more distributed energy resources (DER) are added to the network and electrification occurs. Of particular importance will be the ability to see EV charging patterns and demand at a street level to manage the network more effectively. To improve visibility of low voltage networks, distribution networks will require allowances to invest in technologies to enable this.

Visibility, while important, is only one part of the puzzle for orchestrating distributed energy resources (DER). Orchestration is the ability to see and manage DER in real-time to maintain system stability. Orchestration also allows distribution networks to utilise DER to reduce peak demand, reducing the need for additional physical infrastructure build on their networks.

Another key element for orchestration is operations, which enables a network to send signals to households or devices to respond when required. This is usually enabled by a software and communications platform like an Advanced Distribution Management System (ADMS) and smart DER devices (e.g., a smart EV charger) which can receive communications from the ADMS to provide required responses. Several distribution networks in New Zealand already have an ADMS.

When combined with the mechanisms to provide consumers with compensation for the services they provide to the electricity system, outlined in recommendations i to k, orchestration can deliver improved outcomes for both consumers and the electricity system.

Orchestration will also be important to enable improved use of DER for value stacking flexibility services. For example, if retailers act as aggregators to provide DER response for wholesale energy services, it will be important for this to occur in a way that operates within network stability constraints. One way to achieve this is through the development of dynamic operating envelopes which provide near real-time boundaries within which a distribution network can operate and sets effective limits on the level of DER response that can occur at one time to maintain system stability.[149]

While the term Distribution System Operator (DSO) is nascent and evolving, many of these developments – improved visibility, real-time operations at a low voltage level, and dynamic operating envelopes – are likely to be a part of a DSO journey. Some of this work is underway as part of the ENA's Network Transformation Roadmap. The first step on this journey will be investment in low voltage visibility and operations platforms like ADMS to enable the smart system of the future.

149 Australian Renewable Energy Agency, Dynamic Operating Envelopes Workstream, 2022

Recommendation theme 5: Drive decarbonisation through electrification

Under our preferred pathway, there would be approximately 22 TWh of incremental electricity demand in New Zealand by 2050 through the electrification of transport, process heat and buildings. Most of the technologies required to achieve this level of electrification already exist. However, 3 challenges may otherwise constrain the pace of electrification across these sectors:

1. Whole-of-life economic gap: In some cases, it may be less economically attractive to electrify existing processes than to remain with incumbent solutions from a whole-of-life perspective.

2. 'Sticker price' economic gap: In other cases, while it may be economically attractive to electrify from a whole-of-life perspective, the upfront cost of converting presents an economic or perceptual barrier. This is particularly so for private consumers who may be more influenced by the upfront capital cost of purchasing an EV than its lifetime cost factoring in vehicle life, fuel costs, efficiency, etc.

3. Readiness of the electricity sector: The readiness of the electricity sector to accommodate the additional load from electrification may also present a challenge.

We outline 3 areas where government policy has, and can further, encourage electrification:

n. Extend Clean Vehicle Standards to signal a ban on internal combustion engine (ICE) vehicle imports

o. Extend GIDI funding (if required)

p. Further improve the Emissions Trading Scheme (ETS) in line with New Zealand's emissions targets

n. Extend Clean Vehicle Standards to signal a ban on ICE vehicle imports

With nearly 70% of all transport emissions coming from cars, SUVs, utes, vans, and light trucks, it is important that appropriate incentives are in place for private consumers and light vehicle fleet operators to choose EVs. While the lifetime cost of EV ownership is already nearing or surpassing equality with ICE vehicles today, the up-front capital cost (or 'sticker price') of buying an EV today is significantly higher than the price of an ICE vehicle. Addressing this gap is important to influence consumers to buy EVs.

The Clear Car Act makes headways in driving uptake of EVs both through consumer incentives and clear policy directives to car importers. However, there are 2 ways New Zealand could do more:

- Signal a future ban on the import of internal combustion engine (ICE) vehicles.
- Extend the Clean Car standard to provide a longer-term signal for the tightening of standards.

These measures would provide additional certainty to enable consumers, vehicle manufacturers, and importers to transition effectively.

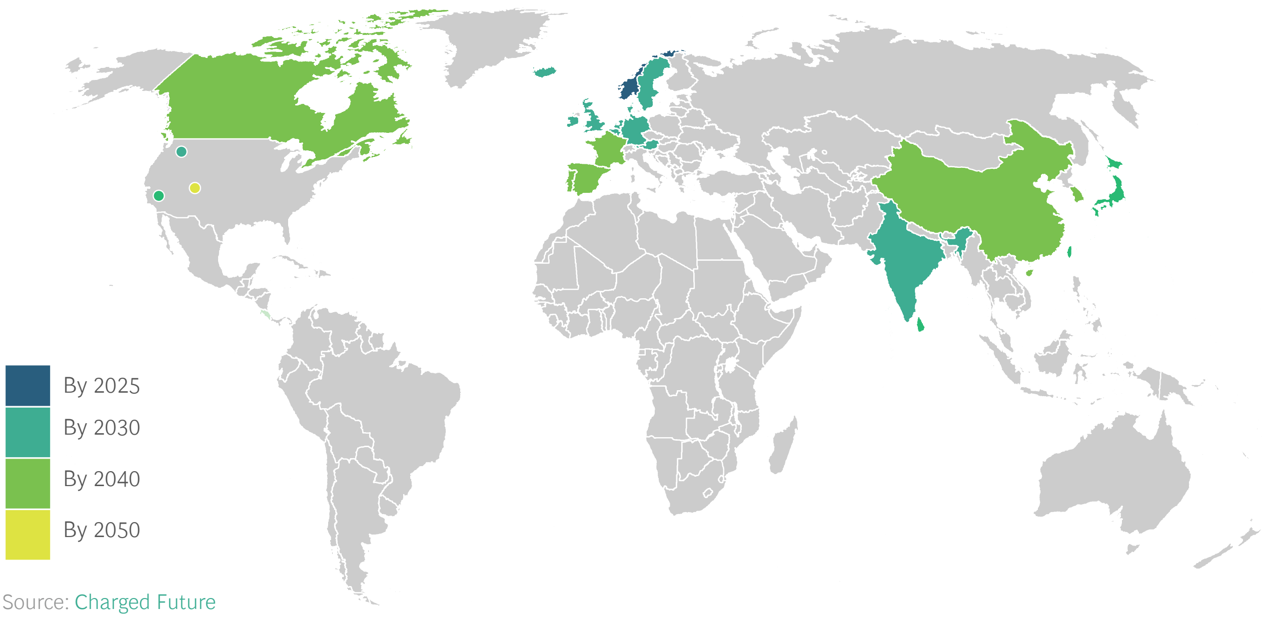
Signal a future ban on ICE vehicles

As of 2021, 31 countries and US states have made public commitments to ban the sale of ICE vehicles, outlined in Exhibit 101.

New Zealand signed a non-binding pledge to ban the sale of new ICE vehicles by 2040 or earlier at COP26 in 2021. This indicates the intention of the Government to announce such a ban. The CCC also recommended that light ICE vehicles be phased out in the early 2030s in its vision for New Zealand.

To date, however, there have been no formal announcements. To minimise the risk of higher cost outcomes for New Zealand, timing a ban with bans from other countries with right-hand-drive vehicle markets would be appropriate. Based on recent

Exhibit 101: 31 countries and US states with ICE vehicle bans



Source: Charged Future

announcements (including UK bringing forward its ban to 2035 and Japan introducing a ban for 2035), this suggests a ban of no later than 2035 would be appropriate.

Extend the Clean Car Standard to signal a tightening of standards

The current Clean Car Standard only outlines targets for the coming 5 years. While the standard will likely be reviewed and extended periodically, providing long-term signals (while subject to change) would allow the automotive industry to plan the transition more effectively. Ideally, the Clean Car Standard would provide an indicative roadmap on the tightening of emissions requirement through to an eventual ban on ICE vehicle imports.

o. Extend GIDI funding (if required)

The original $69 million GIDI fund helped fund 53 major industrial decarbonisation projects that expect to save a total of 7.5 million tonnes of CO_2 over their lifetime. This equates to an abatement cost of ~$9/tonne or ~$25 total abatement cost including the $117 million industry contribution which represents a highly efficient outcome for the Government, considering the current New Zealand carbon price of ~$87/tonne.

Of the projects approved to date, 28 projects involved electrification, often replacing existing high carbon heat sources with electric heat pumps. The fund is now into Round 4 and forms part of a $650 million expansion to be administered over 4 years.

Depending on how successful the next 4 years of GIDI funding is, there is the option to further expand and extend funding to achieve rapid decarbonisation of industrial heat by 2030.

p. Improve the Emissions Trading Scheme (ETS) in line with New Zealand's emissions targets

New Zealand needs a clear cost associated with emissions within the market; the country's reformed Emissions Trading Scheme (ETS) already provides an overarching market mechanism to support this outcome. The ETS reforms, finalised in June 2020 as part of the Climate Change Response (Emissions Trading Reform) Amendment Act, legislated broad reforms to better incentivise businesses to reduce emissions, including:

- A cap on emissions under the ETS as well as the associated regulatory settings for implementation including auctioning volumes and rules
- Provisions for long-term phasing-down of free emissions allocations currently provided to emissions-intensive and trade-exposed industries
- Reforms to the forestry sector including simplified accounting measures
- A levy/rebate system and carbon price applicable to biogenic emissions from agriculture, to run in parallel with the ETS from 2025

The price of NZUs has increased significantly since the reform, sending a strong economic signal to decarbonise. To drive further improvements to the ETS, it will be important to regularly review the limit on the number of units available for auction, the trigger price for the cost containment reserve and the auction reserve price. This will ensure that the price signals sent by the ETS remain sufficient.

Recommendation theme 6: Enable the implementation of this roadmap

This report has outlined a roadmap that will deliver a decarbonised energy system with improved affordability and improved energy security. However, for this to be delivered it will require a concerted effort across the sector, government, and other key stakeholders.

We outline 2 recommendations to drive this forward:

q. Deliver this whole-of-sector roadmap, including coordination with the National Energy Strategy

r. Implement a sector workforce development strategy

q. Deliver this whole-of-sector roadmap, including coordination with the National Energy Strategy

To support the future electricity system this roadmap needs to be delivered. It also needs to feed into the National Energy Strategy. For this roadmap to drive real change, we propose the immediate next steps:

1. The sector develops and signs a commitment that demonstrates broad support for the roadmap and outlines concrete next steps to ensure its effective implementation.
2. The sector establishes a tracking and monitoring mechanism to effectively measure progress against the roadmap and to jointly hold itself to account against its commitment.
3. The sector engages in constructive dialogue with government and other key stakeholders on its commitment to understand common points of alignment and potential differences.
4. The sector incorporates the commitment and stakeholder feedback in its engagement on and submissions to the National Energy Strategy.

It is also important that a forum is established and facilitated for the sector to enable this commitment in a way that mitigates competition concerns.

Part of the roadmap will also need to consider the workforce transition to enable a significant scale up of electricity infrastructure to be developed.

r. Implement a sector workforce development strategy

The electricity sector workforce in New Zealand is estimated to comprise 8,000 roles today across generation, transmission, distribution, retail, and contract service providers. The 2022 sector-funded research Re-Energise – Ngā Mahi A Māui, a workforce development strategy estimates that the sector will require 700 additional engineers, technicians, and trade workers per year to grow and replace workers who leave the sector. In their report *Crafting a path for New Zealand's 100% renewable Energy Market*, Contact Energy estimated that a more renewable based energy market could support 350 new permanent jobs and 7,500 construction jobs over the next 10 years.[150]

The skills and composition of those employed within the sector will also change as the technologies deployed across the system vary and the functions of various participants within the system change. The *2021 Race for 2030 Developing the future of the energy workforce* report highlights some of the workforce shifts we might anticipate throughout the energy transition:[151]

- Shifting renewable-energy focused jobs in design, manufacturing, and installation (up to 80% of jobs today) to renewable-energy jobs in operation and maintenance (up to 50% of jobs by 2030)
- Increasing demand for a 'digitally-enabled workforce' within the sector including data specialists, cyber security specialists, and software programmers
- Increasing requirements for 'green job' skills encompassing environmental awareness and an understanding of sustainability concepts

The Race for 2030 report also highlighted some of the global skill shortages already being experienced as the electricity sector transitions, including but not limited to solar PV certified electricians, construction managers, EV infrastructure engineers and specialist truck drivers.[152]

Compounding the challenge for the future workforce, 3 issues already exist in New Zealand's electricity sector:

1. **An ageing workforce:** According to Infometrics, a quarter of the electricity sector workforce is aged 55+ years, which is represents a large number relative to the rest of the New Zealand economy. At the same time, Transpower's Whakamana i Te Mauri Hiko report indicates that the sector has historically experienced low turnover rates since the 1960s, meaning workforce development processes have been designed to replace small numbers only.[153] The silver lining to the 'silver economy' is that it contributes to New Zealanders living longer, healthier, and more active lives.[154]
2. **Talent attraction challenges:** With New Zealand reaching record low unemployment of 3.2% in the December 2021 quarter, the 5th equal lowest in the OECD, there is fierce competition for talent. The electricity sector faces challenges in recruiting local new talent for several reasons including:
   - Vocational training, which represents a major pathway into the electricity sector, is not seen as attractive to young New Zealanders, with schools biasing toward university pathways

150 Contact Energy, Crafting a path for New Zealand's 100% renewable electricity market, 2021
151 Race for 2030, Opportunity Assessment Reports, 2021
152 Race for 2030, Opportunity Assessment Reports, 2021
153 Re-Energise, Workforce Development Strategy, 2022
154 BCG, Navigating Future Uncertainty in New Zealand with Megatrends, 2022

- For those that do opt for vocational training, other sectors (e.g., construction) and regions (e.g., Australia) compete for employees and are seen to provide more attractive opportunities.

3. **Risks to supply of migrant workforce:** Historically, much of the sector's workforce gap was filled through the migrant workforce. However, a signalled shift in the Government's immigration policies will reduce the availability of lower-skilled offshore workers. The exclusion of roles such as cable jointers from the Essential Skills List, and the salary cap rise from $55,000 to $79,560, will limit the ability to hire offshore for base field roles. COVID-19 and resulting border restrictions have exacerbated this challenge.

The 2022 Re-Energise report lays out a workforce development strategy consisting of 13 recommendations under 4 strategic goals:[155]

Strategic goals	Recommendations
Facilitating flexibility from consumers	1. Build a platform for sector growth 2. Build a platform for sector discovery 3. Raise the profile 4. Develop community-focused campaigns
Design for intuitive career pathways	5. Highlight careers and pathways 6. Build interoperable standards and competencies
Build a resilient workforce	7. Find a united vision and shared approach 8. Commit to growth 9. Build a platform for rapid training and upskilling 10. Design for workplace diversity
Partner with Māori	11. Inspire Māori to enter the sector and thrive within it 12. Develop cultural leadership 13. Build partnerships

As the sector transitions, we also recommend that existing staff are retrained and redeployed into new areas of need.

The workforce challenges confronting the electricity sector as it decarbonises will likely be similar to those experienced across the country as New Zealand transitions to a low emissions economy. MBIE has established a Just Transitions Unit to coordinate this transition.[156] We recommend the electricity sector workforce strategy is executed in alignment with the Just Transitions Unit.

155 Re-Energise, Workforce Development Strategy, 2022
156 Ministry of Business, Innovation and Employment, Just Transition, 2022

9 Conclusion

Aotearoa New Zealand's future is electric. As this report sets out, by increasing renewable electricity and electrifying transport and heating, New Zealand can take great strides towards our decarbonisation ambition. It is estimated that 3.8 Mt CO_2-e can be abated through renewable electricity generation and 18.4 Mt CO_2-e through electrification annually by 2050. This constitutes ~5% and ~22% of New Zealand's total gross emissions today.

New Zealand's electricity sector will make a meaningful impact, but decarbonising won't be easy. Increasing renewables, both to decrease reliance on fossil fuels and meet increasing demand for electricity, involves planning, consenting, building, connecting, and operating more generation, storage, and network infrastructure than ever before.

To meet New Zealand's peak energy demand, the system will need a combination of open cycle gas turbines (possibly running on biofuels in the future), batteries, other storage, smart demand, and demand response. And in dry years, when hydroelectricity capacity is limited, demand will need to be met through renewable overbuild, open cycle gas turbines (possibly using biofuels), other storage technologies and demand response – particularly from large industrial consumers. New Zealand will also need electricity networks that can support an expanded, more distributed system, underpin smart demand, and meet the changing needs of consumers.

Our modelling shows that electrification will significantly advance New Zealand's decarbonisation. As well as unprecedented investment to build the infrastructure of the future energy system, it will take effective policy – policies to drive uptake of electric vehicles, heat pumps and industrial processes.

To ensure a smooth transition for consumers, businesses, and the sector, we've recommended the following priorities for the sector and government:

1. Support accelerated renewables development
2. Encourage the right energy and capacity mix
3. Scale transmission and distribution network investment
4. Enable a smart electricity system
5. Drive decarbonisation through electrification
6. Enable the implementation of this roadmap

If successfully implemented, the New Zealand electricity sector will make the maximum possible contribution to the country's decarbonisation. This in turn will mean affordable and reliable energy for consumers and prosperity for generations to come.

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The report would not be as comprehensive, nor would BCG have been able to present a holistic, whole-of-sector view in the way it has if these parties had not engaged so constructively with BCG. It is testament to what can be achieved to address one of the most pressing challenges of our time through the hard work and engagement of a diverse set of stakeholders.

Glossary

In this section, we have endeavoured to clarify all acronyms / technical terminology that have been used throughout the report. The table below is intended to serve as a reference when reading through the report.

Term	Description		
ADMS	Advanced Distribution Management Systems	**FSR**	Future Security and Resilience
AEMO	Australian Energy Market Operator	**GDP**	Gross Domestic Product
AI	Artificial Intelligence	**GIC**	Gas Industry Company
AMP	Asset Management Plan	**GIDI Fund**	Government Investment in Decarbonising Industry Fund
BCG	Boston Consulting Group	**Greenhouse gases**	Carbon dioxide, methane, nitrous oxide, and hydrofluorocarbons. These gases all cause changes in the earth's atmosphere.
BEV	Battery Electric Vehicle	**Gross emissions**	The greenhouse gases that an economy produces, ignoring carbon offsets (e.g., from forestry)
c/kWh	Cents per kilowatt hour	**GST**	Goods And Services Tax
CAPEX	Capital Expenditure	**GW**	Gigawatt
CBD	Central Business District	**GWh**	Gigawatt Hours
CCC	Climate Change Commission	**Huntly**	Refers to Huntly Power Station
CCGT	Combined Cycle Gas Turbines	**HVDC**	High Voltage Direct Current
CCS	Customer Compensation Scheme	**ICCC**	Interim Climate Change Committee
CCD	Clean Car Discount	**ICE**	Internal Combustion Engine
DER	Distributed Energy Resources	**IEA**	International Energy Agency
ECNZ	Electricity Corporation of New Zealand	**IoT**	Internet Of Things
EDB	Electrical Distribution Business	**IPAG**	Innovation & Participation Advisory Group
EECA	Energy Efficiency & Conservation Authority	**IRA**	Inflation Reduction Act
ENA	Electricity Networks Association	**Kt**	Kilotonne
ENZ	Concept Consulting's Whole of Economy Model	**Lake Onslow**	Refers to the Lake Onslow pumped hydro project
ERCOT	Electric Reliability Council of Texas	**LCOE**	Levelised Cost of Energy
ERP	Emissions Reduction Plan	**LV**	Low Voltage
ETS	Emissions Trading Scheme	**MBIE**	Ministry For Business, Innovation, and Employment
EV	Electric Vehicle	**MDAG**	Market Development Advisory Group
FIR	Fast Instantaneous Reserves	**MEUG**	Major Energy Users Group
		MREP	Melbourne Renewable Energy Project

Mt	Mega tonne	**PPA**	Power Purchase Agreement
MW	Megawatt	**PV**	Photovoltaic(s)
MWh	Megawatt Hours	**RAB**	Regulated Asset Base
NEM	National Electricity Market (Australia)	**Rankines / Rankine units**	A type of steam turbine currently in use at Huntly power station
Net emissions	The greenhouse gases that an economy emits minus those gases taken out of the air, e.g., by new forestry planted	**RERT**	Reliability And Emergency Reserve Trader
NI	North Island	**Residual load**	The amount of electricity that cannot be met by intermittent renewable capacity (e.g., wind and solar)
NPV	Net Present Value	**REZ**	Renewable Energy Zones
NREL	National Renewable Energy Laboratory	**RMA**	Resource Management Act
NZ	New Zealand	**RRO**	Retailer Reliability Obligation
NZEM	New Zealand Wholesale Electricity Market	**SIR**	Sustained Instantaneous Reserve
NZU	New Zealand Unit	**SRMC**	Short Run Marginal Cost
OCC	Official Conservation Campaign	**Tiwai Point**	Refers To Tiwai Point Aluminium Smelter
OCGT	Open Cycle Gas Turbines	**Tonne (t) CO_2-e**	The unit for measuring the climate impact of the greenhouse gases and stands for tonnes of carbon dioxide equivalent. Each of the different greenhouse gases has a different impact on the atmosphere, so a weighting is given to the other gases so that we have an idea of the overall impact of greenhouse gases emitted.
OECD	Organisation For Economic Co-Operation and Development	**TOTEX**	Total Expenditure
OFGEM	Office Of Gas and Electricity Markets (UK)	**TWh**	Terawatt Hours
OPEX	Operating Expenditure	**UNGI**	Underwriting New Generation Investments
ORC	Concept Consulting's Electricity Market Model	**VPP**	Virtual Power Plant
ORDC	Operating Reserve Demand Curve	**VRE**	Variable Renewable Electricity
PJ	Petajoule	**WEC**	World Energy Council
PJM	Pennsylvania - New Jersey - Maryland (US Eastern Seaboard Market)		

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