TRANSPOWER

Lower South Island: Major Capex Proposal Longlist Consultation

Attachment 2: Demand and Generation Scenarios

November 2026



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Cover image credit: Mercury NZ – Kaiwera Downs Wind Farm

1 Overview

This attachment outlines the demand and generation scenarios we propose to use for our Lower South Island Major Capex Proposal (MCP) investigation. To apply the regulated Investment Test, we must make assumptions about future demand and generation. This attachment sets out those assumptions and explains how they will be used in our analysis. Most of our assumptions are based on the benefit-based charges (BBC) Assumptions Book v3.0 (Assumptions Book)[1], except where more up-to-date, relevant, or region-specific information is available.

We evaluate investment options under a range of market development scenarios. Each scenario represents a plausible future electricity system based on a set of demand, generation, and other key assumptions. Considering multiple scenarios ensures that our economic assessment is robust to a range of potential futures. Each market development scenario includes assumptions about:

- future electricity demand, including assumptions regarding base demand, electric vehicle (EV) uptake, solar PV uptake, distributed energy storage, etc.
- existing, decommissioned and future new generation connected to the national grid
- capital and operating costs for existing and future new generation
- fuel availability, fuel cost, and carbon cost for generation
- grid-connected energy storage.

The Investment Test requires us to use the *market development scenarios* produced by the Ministry of Business, Innovation and Employment (MBIE) or reasonable variations of their scenarios. MBIE's scenarios are called the Electricity Demand and Generation Scenarios (EDGS)[2] and were last updated in July 2024. They consist of five scenarios:

- **Reference:** Current trends continue
- **Growth**: Accelerated economic growth
- **Constraint:** Slower economic growth
- **Environmental:** More ambitious national emissions reduction targets are set than in the Reference scenario
- **Innovation:** Increased rates of development and uptake of new technologies.

For this investigation, we use MBIE's 2024 EDGS as the scenario framework for our demand and generation assumptions. However, the EDGS primarily provide assumptions at a national level, so more detailed regional and GXP-level assumptions are required for this investigation.

For demand, we have used the 2024 EDGS alongside historical data and customer information to develop the regional and GXP forecasts presented in Section 2. For generation, we have used the Assumptions Book v3.0 alongside customer information to develop the more detailed generation assumptions required for our modelling, as discussed in Section 3.

1 Final Assumptions Book v3.pdf
2 Electricity Demand and Generation Scenarios (EDGS)

2 Demand assumptions

This section presents the Lower South Island regional EDGS peak load forecast variations we propose to use for this investigation. For this investigation, we have focused on Lower South Island network demand[3], as this is most relevant to assessing potential transmission constraints associated with new generation and load connecting in the region.

We welcome information on additional load projects in the region, particularly their timing, location and preferred grid connection. We will use these demand forecasts in the next phase of the MCP investigation to evaluate a shortlist of development plans.

2.1 Regional refinements

We have used the 2024 EDGS as a basis for our demand forecasts, with updates to selected assumptions:

- **Regional GXP forecasts:** As the 2024 EDGS demand assumptions are primarily national, we have disaggregated these assumptions to regional and GXP levels, supplemented by updated historical data and information from customers.
- **Peak demand:** We have aligned our national energy forecasts with MBIE's EDGS, but use our own GXP-level demand models to forecast peak demand. These models provide more detailed profiles and better capture how peak demand varies across the scenarios.
- **Process heat:** We have moderated the assumed rate of process heat electrification in early years, placing greater weight on known potential heat electrification projects rather than scenario-level uptake assumptions. This particularly affects the Environmental and Innovation scenarios, where EDGS assumes relatively high rates of electrification.
- **Solar uptake:** We have increased the level of residential and commercial solar uptake to be more in line with assumptions in our Te Kanapu scenarios[4]. The EDGS levels of solar uptake were relatively low.
- **Battery storage:** We have increased the starting levels of solar installations paired with batteries to better reflect current installation levels and uptake.

2.2 Prudent forecast

In addition to the 'expected' forecasts presented in Section 2.3, we have developed a 'prudent' peak load forecast to represent a reasonable upper bound for demand. We use the prudent forecast to determine the timing of prospective investments, whereas we use expected forecasts to calculate expected benefits of an investment.

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3 Network demand south of Twizel.

4 Te Kanapu Our Energy Scenarios

The five EDGS-based forecasts are expected forecasts, with starting demand levels based on historical trends. However, historical peaks do vary from year to year such that demand could be higher than indicated by the 'expected' starting value. For example, if there were very cold temperatures associated with a 1-in-10-year weather event we would expect that demand could be significantly higher than for an average year. The prudent forecast accounts for this risk.

The prudent forecast was developed by first scaling the Environmental scenario using the ratio between the P90 and P50 probability of exceedance figures derived from regressions of historical demand. This scaling is applied over the first seven years of the forecast to reflect short-term variability in peak demand, after which the scaling ratio remains constant for the remainder of the forecast horizon. As such, the prudent forecast exhibits higher peak demand in the early years relative to the expected forecast, while maintaining the same underlying long-term growth trajectory.

We use the Environmental scenario as the basis for calculating the prudent forecast as it assumes a high level of electrification and includes most new known step loads but excludes some of the more speculative new loads.

2.3 Lower South Island forecast

Figures 1 and 2 present our proposed peak load (MW) and energy demand (TWh) forecasts, respectively, for the Lower South Island region for each of the five EDGS scenarios. Table 1 and Table 2 present the corresponding winter and summer peak load forecasts in 2030, 2040, 2050, and 2060, broken down by the factors contributing to that growth:

- **Base growth:** the underlying growth in demand driven by factors such as population and economic growth
- **Step loads:** new demand that might appear in the future from new developments, such as new commercial and residential developments
- **EV:** the uptake of EVs and the "smartness" of their charging
- **Solar:** the uptake of residential and commercial solar photovoltaic panels
- **Battery:** the uptake of residential and commercial battery storage packs
- **Process heat:** the electrification of industrial processes such as the conversion of coal and diesel boilers to electric boilers and new loads associated with process heat
- **Data centres:** significant new data centre loads.

The assumptions for each of these factors vary across the scenarios, resulting in a range of demand forecasts. For example, average annual base peak growth[5] between 2026 and 2060 ranges from 0.2% to 1.2% across the scenarios. Differences in the other demand components further widen the range of forecast outcomes.

Anticipated new step loads are a key driver of demand growth in the Lower South Island. In particular, the anticipated new Datagrid data centre, electrification of the dairy factory at Edendale, and an additional pot line at Tiwai contribute significantly to demand growth in the early years of all scenarios. Other anticipated loads are less certain, so we have varied their inclusion across the

[5] This is the growth of the peak before the addition of step loads, process heat, EVs, PVs and data centres.

scenarios to capture a range of potential future demand outcomes. This is discussed further in Section 2.4.

Figure 1 shows the peak load forecast (in MW) for the Lower South Island region for the five EDGS variations plus a prudent forecast using the Environmental scenario (refer to section 2.2). Figure 2 shows gross energy demand (in TWh) for the same region. Table 1 and Table 2 provide a breakdown of the peak load forecasts by the factors contributing to the growth. More detail regarding step loads is provided in section 2.4.

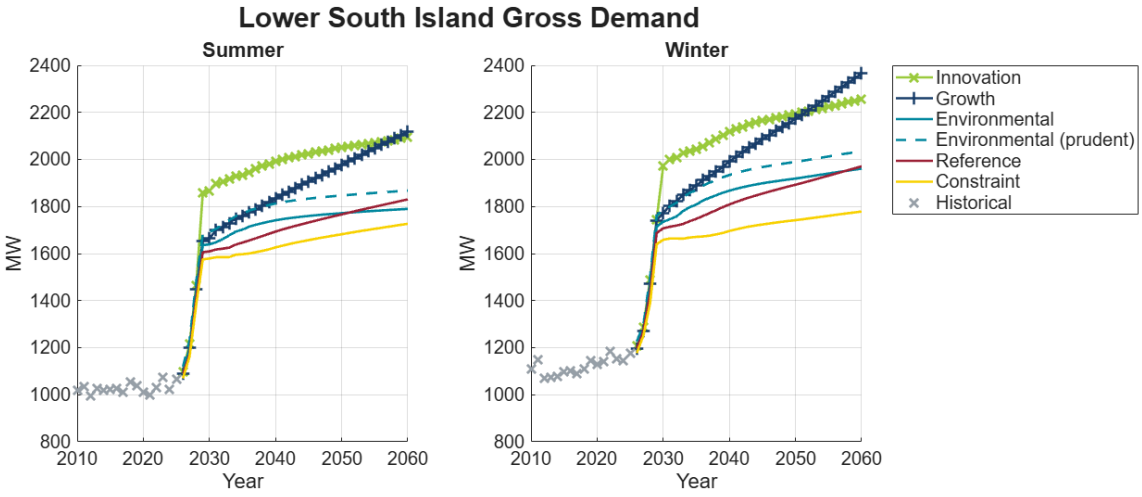

Figure 1: Lower South Island region peak gross[6] demand forecast, in MW

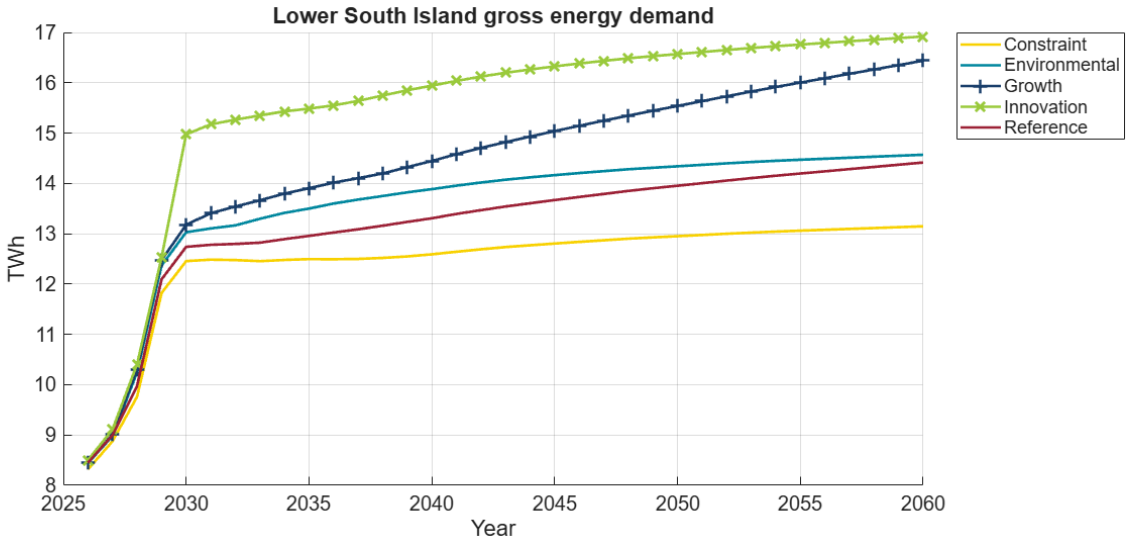

Figure 2: Lower South Island region gross energy demand forecast, in TWh

6 Gross demand is all demand excluding embedded generation.

Table 1: Lower South Island region winter peak demand forecast, in MW

Scenarios	Year	Peak	Base	Step loads[7]	EV	Solar	Battery	Process heat[8]	Data centre[9]
Constraint	2030	1659	1168	173	6.3	-3.0	-3.2	14.4	360
	2040	1696	1175	187	19.3	-4.7	-5.2	26.4	360
	2050	1742	1174	187	49.0	-7.2	-9.0	53.8	360
	2060	1779	1175	187	72.0	-8.9	-14.0	77.2	360
Reference	2030	1707	1192	201	6.2	-3.3	-4.2	14.7	360
	2040	1809	1247	213	23.7	-6.1	-10.8	47.9	360
	2050	1893	1290	213	52.5	-9.8	-20.9	79.7	360
	2060	1970.7	1337.3	213	76.0	-12.0	-31.8	103.2	360
Environmental	2030	1735	1179	214	5.4	-3.7	-5.0	44.7	360
	2040	1867	1238	247	19.3	-8.5	-17.6	93.7	360
	2050	1919	1263	247	37.7	-13.8	-36.8	132.5	360

[7] We show the sum of the maximum demands of each step load rather than the sum of their demand at the time of the regional peak. This gives a clearer indication of the variation in step loads between scenarios. The step load here does not include data centre loads as they are listed separately.

[8] Includes a 30 MW mineral processing load in the Environmental, Growth and Innovation scenarios, and a 200 MW silicon smelter load in the Innovation scenario.

[9] Denotes the forecasted MW demand capacity of data centres, rather than demand at the time of the regional peak.

Scenarios	Year	Peak	Base	Step loads[7]	EV	Solar	Battery	Process heat[8]	Data centre[9]
	2060	1961	1295.5	247	51.6	-16.8	-56.7	156.7	360
Growth	2030	1772	1213	217	6.7	-3.5	-5.2	44.8	360
	2040	1990	1367	279	27.9	-8.1	-18.8	57.5	360
	2050	2173	1507	279	60.1	-11.5	-34.8	93.5	360
	2060	2366	1668	279	88.6	-13.1	-51.9	119.2	360
Innovation	2030	1973	1190	246	5.6	-3.5	-5.0	244.9	360
	2040	2117	1252	309	20.0	-9.2	-17.8	281.9	360
	2050	2194	1293	309	40.6	-14.8	-37.2	331.2	360
	2060	2255	1339	309	57.0	-18.0	-57.0	357.8	360

Table 2: Lower South Island region summer peak demand forecast, in MW

Scenarios	Year	Peak	Base	Step loads[10]	EV	Solar	Battery	Process heat[11]	Data centre[12]
Constraint	2030	1579	1066	168	7.1	-9.8	-2.6	16.4	360
Constraint	2040	1626	1085	182	20.2	-11.7	-5.6	30.3	360
	2050	1682	1102	182	46.8	-19	-9.3	54.1	360
	2060	1727	1119	182	65.6	-24.2	-14.3	74.9	360
Reference	2030	1609	1080	189	6.8	-10.4	-3.9	16.5	360
	2040	1694	1126	200	22.9	-14.5	-12.4	49.4	360
	2050	1767	1171	200	45.1	-23.1	-22.5	75.8	360
	2060	1830	1217	200	61.9	-29.8	-34.1	96.5	360
Environmental	2030	1639	1072	201	5.7	-11.5	-4.6	46.6	360
	2040	1742	1116	233	18.0	-20	-20.4	94.1	360
	2050	1772	1138	233	30.5	-33.1	-38.7	125.9	360

[10] We show the sum of the maximum demands of each step load rather than the sum of their demand at the time of the regional peak. This gives a clearer indication of the variation in step loads between scenarios. The step load here does not include data centre loads as they are listed separately.

[11] Includes a 30 MW mineral processing load in the Environmental, Growth and Innovation scenarios, and a 200 MW silicon smelter load in the Innovation scenario.

[12] Denotes the forecasted MW demand capacity of data centres, rather than demand at the time of the regional peak.

Scenarios	Year	Peak	Base	Step loads[10]	EV	Solar	Battery	Process heat[11]	Data centre[12]
	2060	1790	1158	233	39.2	-42.9	-59	147.1	360
Growth	**2030**	1665	1094	203	7.1	-11	-5.0	46.6	360
	2040	1834	1206	265	26.4	-20.6	-20.8	62.5	360
	2050	1976	1324	265	49.9	-31.3	-37.3	91.9	360
	2060	2118	1454	265	69.5	-41	-55.9	114.3	360
Innovation	**2030**	1866	1079	227	5.8	-10.7	-5.1	246.9	360
	2040	1991	1129	289	18.9	-20.7	-20.8	286	360
	2050	2050	1172	289	33.4	-35.5	-38.4	324.6	360
	2060	2093	1215.1	289	43.8	-46.4	-59.2	348.2	360

2.4 Step loads

Table 3 sets out capacities of major new load developments that we expect to connect in the region and that we have incorporated into our demand scenarios[13]. We have varied the inclusion of these step loads across scenarios to capture a broad range of demand futures. The Innovation scenario includes all identified step loads, reflecting greater electrification of industry, while other scenarios exclude some developments considered less likely to proceed.

Where a step load is included across all scenarios based on its likelihood, we may test a sensitivity in which it does not eventuate. Large step loads can materially affect the timing and scale of the investment need, so testing pathways with and without them helps us identify investments that are common across different demand futures and therefore potentially low regret.

We intend to update our forecasts as new information becomes available, including through this consultation. We welcome information on potential new significant loads in the region, including their expected capacity, location, timing, and demand profile (e.g., when and how the new load would vary by day and season).

Table 3: Major step loads in the Lower South Island region by scenario[14]

Point of connection (POC)	Year	Constraint	Reference	Environmental	Growth	Innovation
Balclutha • Meat processing • Industrial development	**2030**	5	5	7	7	7
	2035	5	5	7	7	7
Brydone • Daiken Southland	**2030**	0	0	0	0	10
	2035	0	0	0	0	10
Cromwell • Mining • Tourism and accommodation • Residential subdivisions	**2030**	14.6	19.9	19.9	19.9	19.9
	2035	19.3	24.6	24.6	24.6	24.6
Edendale 33 kV	**2030**	0	0	0	0	0

[13] Information on potential new step loads has been provided by distribution companies through our annual Transmission Planning Report forecast customer survey process and is supplemented by information provided directly by stakeholders.

[14] All load amounts are in MW. This table excludes Points of Connection (POCs) with less than 5 MW cumulative step loads by 2035.

Point of connection (POC)	Year	Constraint	Reference	Environmental	Growth	Innovation
• Meat processing • Dairy load	**2035**	0	0	10	10	10
Frankton • Tourism and accommodation • Commercial development	**2030**	1	10.6	13.3	15.7	22.9
	2035	1	10.6	13.3	15.7	22.9
Gore • Meat processing	**2030**	0	6.5	6.5	6.5	6.5
	2035	0	6.5	6.5	6.5	6.5
Halfway Bush (Aurora) • Healthcare • Meat processing • Industrial electrification	**2030**	8.5	9.5	9.5	9.5	13.5
	2035	8.5	9.5	9.5	9.5	13.5
Invercargill 33 kV • Industrial development • Hydrogen transport	**2030**	8.7	11.7	17.3	17.3	217
	2035	8.7	13.2	18.8	18.8	219
Invercargill 66 kV • Dairy electrification	**2030**	0	0	0	0	0
	2035	0	0	0	30	30
North Makarewa • Residential subdivisions • Hydrogen and electric aviation	**2030**	0	0	2.6	2.6	2.6
	2035	0	0	9	9	9
North Makarewa • Datagrid	**2030**	360	360	360	360	360
	2035	360	360	360	360	360
Naseby • Industrial development	**2030**	0	0	0	0	8
	2035	0	0	0	0	8
Puna Awa • Dairy load	**2030**	83	83	83	83	83
	2035	92	92	92	92	92

Point of connection (POC)	Year	Constraint	Reference	Environmental	Growth	Innovation
Tiwai • Industrial load	**2030** [15]	50	50	80	80	80
	2035	50	50	80	80	80

Q10. **Do you consider our demand assumptions appropriate for this investigation? If not, what changes would you suggest?**

Q11. **Are you aware of any planned or potential industrial, commercial, residential or other developments that could significantly affect electricity demand in the region and are not reflected in our assumptions? If so, please provide any information that could help inform our demand forecasts, such as the location, timing, capacity, likelihood and/or stage of commitment, and load profile of such development.**

[15] Post producing our forecasts we became aware of a recent announcement that this change is expected from October 2027. We intend to incorporate this change into our finalised forecast for this project.

3 Generation assumptions

This section presents information relating to the generation assumptions that we propose to use for this project. We welcome any information regarding additional generation projects in the region, especially on project timing, location and preferred grid connection.

Generation assumptions apply to our:

- **OptGen generation expansion plan model**, which determines the location, timing, and technology of new (modelled) generation.
- **SDDP wholesale market model**, which simulates the wholesale electricity market by calculating a least cost optimal dispatch over the study horizon.

We use these models to evaluate the net electricity market benefit of different investment options.

For generation assumptions, we propose to base our analysis on the assumptions set out in the benefit-based charges (BBC) Assumptions Book v3.0.[16]

We have already identified some variations we intend to apply from Assumptions Book v3.0. These relate directly to the region under investigation and are listed below:

- Adding Puke Kapo Hau/Mahinerangi stage 2 wind farm (192 MW) as a committed project
- Updating our generation stack to include the latest information from our customer pipeline
- Including the uplift of capacity for the Waitaki Power Station when it is upgraded.

Q12. Do you agree with our proposal to use our BBC Assumptions Book v3.0 variations as the basis for our market scenarios for this investigation?

3.1 Existing generation

Existing generation in the Lower South Island region is listed in Table 4 and summarises both plant locations and installed capacities. We assume that these generators will continue to operate throughout the investigation period, and that the following wind farms will be repowered at the end of their technical life:

- White Hill (capacity increase to 97 MW in 2037)
- Mahinerangi stage 1 (capacity increase to 40 MW in 2041).

[16] Assumptions Book | Transpower: The Assumptions Book contains inputs and assumptions we use to calculate benefit-based charges customer allocations under the transmission pricing methodology.

We also assume that the capacity of the Waitaki generator, which represents the Waitaki Power Station, increases to 120 MW in 2036 in line with the upgrade plan recently announced by Meridian[17,18].

Note that some of the generators in Table 4 are not directly connected to the transmission grid but are embedded in the distribution grid. Smaller embedded generation below 10 MW is included in GXP demand forecasts as a reduction in gross demand.

Table 4: Existing Lower South Island generation

Type	Modelled Transmission Node[19]	Modelled Generator Name	Installed Capacity (MW)
Wind	HWB220	Mahiner_s1	36
Wind	NMA220	WhiteHill	58
Wind	GOR110	KaiwDwns1	43
Wind	KIW220	W_KaiweraDow	152
Hydro	OHA220	OhauA	264
Hydro	OHB220	OhauB	220
Hydro	OHC220	OhauC	220
Hydro	BEN220	Benmore	570
Hydro	AVI220	Aviemore	220
Hydro	WTK220	Waitaki	105
Hydro	CYD220	Clyde	432
Hydro	MAN220	Manapouri	800
Hydro	ROX220	Roxburgh1_5	200
Hydro	ROX110	Roxburgh6_8	120
Hydro	HWB220	Waipori1A	12
Hydro	BWK110	Waipori4	8
Hydro	BWK110	Waipori3	7
Hydro	HWB220	Waipori2A1	19
Hydro	BWK110	Waipori2A2	19

[17] No other hydro upgrades will be included in our existing generation model.

[18] Meridian to upgrade Waitaki Power Station | NZX announcement

[19] We model the AC transmission network down to 66 kV in SDDP. Generation which connects below this level is represented at a nearby model node. Hence, the node labels do not correspond to the actual nodes in the system and do not indicate the connection voltages of the respective plants.

Hydro	BWK110	Waipori2A3	19

3.2 Committed generation

In our generation expansion modelling we include 'committed' generation projects which we judge will be commissioned. The timing of this build is exogenously specified in the generation expansion model based on publicly reported development schedules. The conditions by which a project is considered committed are specified in clause D8(1) of the Capex IM. Based on these criteria, the committed generation projects we are aware of are shown in Table 5.

Table 5: Committed Lower South Island generation

Type	Modelled Transmission Node	Modelled Generator Name	Installed Capacity (MW)	Expected Commissioning Year
Wind	HWB110	W_Mahinerang (PukeKapoHau)	192	2030

3.3 Potential generation

The Lower South Island has significant potential for the development of new wind and solar generation, including solar paired with BESS. This potential is reflected in considerable interest from both established and prospective generators, with more than 2,500 MW of generation projects in the investigation or delivery stages of Transpower's connection queue.

Our generation stack comprises the candidate generation projects included in the generation expansion model. From these candidates, the model determines a least-cost capacity expansion plan, selecting the mix of generation required to meet forecast demand at the lowest overall cost.

Table 6 summarises the Lower South Island candidate projects included in the stack for this investigation. Our full generation stack also includes candidate projects in other regions of New Zealand. The table provides the terms used in our modelling and is in line with the information provided in the Assumptions Book. In some cases we have associated generation projects with the closest existing node, but if built these projects may be connected to a new node.

Our generation stack draws on the Generation Stack Report produced by Beca and Concept[20] and has been updated to include projects reflected in Transpower's connection pipeline. We welcome feedback on whether the candidate projects and assumptions we propose to use for the Lower South Island region are appropriate for this investigation, including indicative project timing, assumed capacities, costs, capacity factors, and any relevant project updates.

[20] 2025 Generation Stack Report

Table 6: Lower South Island region generation stack (with costs expressed in 2025 NZD values)

Type	Name[21]	Modelled Transmission Node	Max Build Capacity (MW)	Capital cost if constructed in 2025 ($/kW)	Fixed O&M costs if constructed in 2025 ($/kW/yr)	Average Capacity Factor	Earliest Commissioning Year
Wind	Southland	TMH220	380	3,704	43.5	40.0%	2029
Wind	Kaihiku	TMH220	300	3,594	43.5	40.0%	2029
Wind		INV220	500	3,400	43.5	43.0%	2031
Wind		TMH220	375	3,400	43.5	40.0%	2031
Wind		INV220	259	3,400	43.5	43.0%	2031
Wind		MAN220	700	3,400	43.5	43.0%	2032
Wind		INV220	375	3,400	43.5	43.0%	2032
Wind		HWB220	250	3,400	43.5	40.0%	2032
Wind		NMA220	250	3,400	43.5	43.0%	2032
Wind		NMA220	196	3,400	43.5	43.0%	2032
Wind		WTK220	130	3,499	43.5	40.0%	2032
Wind		INV220	42	3,102	43.5	43.0%	2032
Wind		NMA220	35	3,336	43.5	43.0%	2032
Solar		ROX220	450	1,900	27.4	22.1%	2028
Solar	The Point	TWZ220	357	1,975	27.4	24.1%	2028
Solar		NSY220	310	1,900	27.4	22.1%	2028
Solar		NSY220	300	1,900	27.4	22.1%	2028
Solar		TWZ220	300	1,975	27.4	24.1%	2028
Solar	Twizel Solar Farm	TWZ220	255	1,975	27.4	24.1%	2028
Solar		OHA220	252	1,975	27.4	24.1%	2028
Solar		NSY220	220	1,900	27.4	22.1%	2028
Solar		TWZ220	400	1,900	27.4	24.1%	2030
Solar		GOR220A	140	1,900	27.4	15.7%	2030
Solar	Maniototo	NSY220	300	1,975	27.4	22.1%	2032

[21] We have anonymised projects in our pipeline that are not yet in delivery stage or are not in the public domain.

Type	Name[21]	Modelled Transmission Node	Max Build Capacity (MW)	Capital cost if constructed in 2025 ($/kW)	Fixed O&M costs if constructed in 2025 ($/kW/yr)	Average Capacity Factor	Earliest Commissioning Year
Solar	Twizel Solar Farm	TWZ220	234	1,975	27.4	24.1%	2032
Solar		ROX220	200	1,900	27.4	22.1%	2032
Solar		ROX220	200	1,900	27.4	22.1%	2032
Solar	Haldon Station 1	BEN220	90	1,975	27.4	24.1%	2032
Solar	Haldon Station 2	TWZ220	90	1,975	27.4	24.1%	2032
Solar		NSY220	80	1,900	27.4	22.1%	2032
Solar		NSY220	34	1,975	27.4	22.1%	2032
Hydro	Tuapeka	TMH220	350	9,195	89.0		2037
Hydro	NorthBank	WTK220	260	9,195	89.0		2037
Hydro	Queensberry	CML220A	110	9,195	89.0		2037
Hydro	Dumbarton	ROX220	100	9,195	89.0		2037
Hydro	Barnego	BAL110	80	9,195	89.0		2037
Hydro	HaweaRiver	CML220A	80	9,195	89.0		2037
Hydro	Luggate	CML220A	80	9,195	89.0		2037
Hydro	UpWaiauSth	INV220	80	9,195	89.0		2037
Hydro	LoWaiauSth	INV220	60	9,195	89.0		2037
Hydro	Pukaki	TWZ220	35	9,195	89.0		2037
Hydro	HaweaGates	CML220A	17	9,195	89.0		2037
BESS	BESS_NSY2h	NSY220	830	1,700	25.1		2027
BESS	BESS_ROX2h	ROX220	300	1,700	25.1		2027
BESS	BESS_TWZ2h	TWZ220	580	1,700	25.1		2027
BESS	BESS_TMH2h	TMH220	375	1,700	25.1		2027

3.4 Generation sensitivities

We are aware of two large pumped hydro projects and a hydro capacity project that could materially affect transmission investment needs in the Lower South Island, but whose development remains

uncertain. These include the Lake Onslow and Sutton pumped hydro schemes, as well as a potential increase in Manapouri export capability.

We do not propose including these projects in our core generation scenarios. Instead, we will assess their potential impacts through sensitivity analysis:

- **Pumped hydro:** We propose assessing development pathways both with and without the Lake Onslow and Sutton pumped hydro schemes. These projects represent significant binary uncertainties and may not be developed endogenously by OptGen given their high upfront costs and longer-term system value. Assessing them separately will allow us to understand how pumped hydro could affect the power system and whether there are low-regret transmission investments that are beneficial under either pathway.
- **Manapouri:** We propose a sensitivity that increases Manapouri's export capability to 920 MW, reflecting the potential outcome of a customer project to increase export capability at the hydro station. This sensitivity will help us assess the broader transmission implications of increased generation output from Manapouri.

In addition to our main generation stack, we are seeking information on these potential large-scale pumped hydro schemes. This includes the current stage of project development and level of certainty, preferred grid connection location and type, build capacity, capital and operating costs, expected commissioning dates, and any other relevant information on how these schemes are expected to operate.

Q13. Do you consider our generation assumptions (including assumed capacities, costs and capacity factors) appropriate for this investigation? If not, what changes would you suggest?

Q14. Are you developing a generation project in the Lower South Island region? At what stage are you in developing it (e.g. investigating, consenting, in design, financial investment decision approved, in construction)? If there was sufficient transmission capacity, when would you expect your project to be commissioned?

Q15. Are you aware of any additional generation projects in or near the Lower South Island region that could materially affect our modelling for this investigation?

Q16. If you are considering a new or emerging generation or storage technology, such as pumped hydro or other long-duration storage, can you provide information on its development status and certainty, preferred grid connection, potential build capacity, indicative costs, expected commissioning date, and operating characteristics?[22]

[22] We are particularly interested in cost information for emerging technologies where established cost benchmarks are limited, to help us develop robust assumptions for future system modelling.

4 Scenario weighting

We propose to use four of our five EDGS scenarios, equally weighted, in our market modelling to assess benefits. The selected scenarios are Reference, Environmental, Growth and Innovation, and together they span a range of futures:

- **Reference:** a low-growth future;
- **Environmental:** a medium-growth future;
- **Growth:** high growth future, includes LNG and has lower geothermal generation build costs; and
- **Innovation**: high-growth future, does not include LNG and has lower generation build costs.

Further detail on the demand assumptions for each scenario is provided in Section 2 of this document, and the generation assumptions are documented in Assumptions Book v3.0[23].

Q17. Do you support our use of four of the five EDGS scenarios (Reference, Environmental, Growth and Innovation), equally weighted, as the basis for our market modelling? If not, what would you recommend instead, and why?

[23] Final Assumptions Book v3.pdf



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