Economics of Utility-Scale Solar in Aotearoa New Zealand

Forecasting Transmission and Distribution Network Connected
1 MW to 200 MW Utility-Scale Photovoltaic Solar to 2060

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Prepared for the Ministry of Business, Innovation and Employment

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- Scott Lemon for his research of annual PV generation by location, the Land Cover Database, New Zealand topography, grid exit point (GXP) locations and zone substations.

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This study utilised the following data resources:

- The Electricity Authority's EMI database from which final price and load data were obtained for each GXP.

- Energy Link's monthly EnergyTrendz summary and the ASX electricity futures for an understanding of future electricity prices at the Benmore reference node.

- The NIWA CliFlo Climate Database (hourly global horizontal irradiance and direct and diffuse irradiance) and Solarview.

- Land Cover Database v5.0 of mainland New Zealand, sourced from the Land Resource Information Systems (LRIS) Portal provided by Landcare Research (https://lris.scinfo.org.nz/) and licensed by AMCL for re-use under the Creative Commons Attribution 4.0 International licence (https://creativecommons.org/licenses/by/4.0/).

- Sourced from the LINZ Data Service (https://data.linz.govt.nz/) and licensed by AMCL for re-use under the Creative Commons Attribution 4.0 International licence (https://creativecommons.org/licenses/by/4.0/).

    - A shape file giving polygons of the New Zealand coastline and islands

    - A shape file giving New Zealand lakes. Filtered to only include lakes of area > 0.001.

    - A shape file giving polygons of populated areas (577) in New Zealand. Filtered to 576 to remove the Chatham Islands.

    - A shape file giving power lines across New Zealand

    - A shape file giving roads throughout New Zealand

- Further resources used in modelling irradiance:
  - Reanalysis data (MERRA-2) is from the Global Modeling and Assimilation Office (GMAO) via the Goddard Earth Sciences Data and Information Services Center (GES DISC) (https://gmao.gsfc.nasa.gov/reanalysis/MERRA-2/).
  - Satellite imagery data is from the Center for Environmental Remote Sensing Research, Chiba University (https://www.cr.chiba-u.jp/japanese/database.html) and relicensed by NOAA under an open data license.
  - Elevation data (SRTM 30 m) is from the U.S. Geological Survey (USGS) Earth Resources Observation and Science (EROS) Center (https://www.usgs.gov/centers/eros/science/usgs-eros-archive-digital-elevation-shuttle-radar-topography-mission-srtm-1-arc).
  - Annual results were checked against data obtained from the "Global Solar Atlas 2.0, a free, web-based application is developed and operated by the company Solargis s.r.o. on behalf of the World Bank Group, utilizing Solargis data, with funding provided by the Energy Sector Management Assistance Program (ESMAP). For additional information: https://globalsolaratlas.info Global Solar Atlas (https://globalsolaratlas.info). This data is also licensed under CC BY 4.0."

Glossary (terms used)

Many of these terms are introduced in the text and are collated here to provide an overview understanding.

Term	Meaning
8,760	The number of hours in a year, used to combine capacity of a solar system with its capacity factor to determine energy generated per annum.
Array	Multiple PV modules connected together.
Capacity	The size of a PV generation plant, usually on the AC side, given in Wp.
Capacity factor	Capacity factor of a renewable generator is the measure of the resource available to it and the ability of its capacity (measured in MW) to convert that resource into saleable energy (measured in MWh). It is the ratio of the actual energy output of a generator to its energy output assuming it operates continuously at its maximum rated power.
Capital cost	The cost of building a PV generation plant, given in $/Wp.
Cell	Refers to each 1 kilometre by 1 kilometre land cell covering New Zealand. Note that this is distinct from a PV solar cell; the only use of cell to refer to a PV solar cell in this report is in the discussion about module efficiency and in the definition of module.
Clipping	Related to inverter loading ratio, clipping occurs when the output power of the PV array is greater than the rated input power of the inverter. This requires the inverter to either increase the DC voltage (above the maximum power point), or to clip the AC power output (referred to as self-limiting). Inverters may also self-limit for other reasons, such as high temperatures. Clipping is also referred to as 'inverter saturation'.
Crystalline silicon (c-Si)	Refers to silicon crystals made of solar grade silicon.
Dual-axis tracking	A PV system where the modules are mounted on control equipment that tracks the sun's position from east to west across each day (azimuth) and adjusts the panel tilt to track the sun's angle across a year (elevation tracking).
First-generation	Refers to mature solar generating technology that has been in mass production for a number of years and makes up the majority of solar technology produced (Schwartfeger & Miller 2015).
Fixed angle	A PV system where the modules are fixed in position (they do not track the sun's position).
Generation stack	A detailed list of potential future electricity generation projects in New Zealand covering information such as technology, size, location and cost of each project.
Global horizontal irradiance (GHI)	Solar power, or irradiance, received by a horizontal surface on the Earth (W/m^2). This takes into account all constituents of the atmosphere (that might attenuate some parts of the sun's spectrum) and includes direct horizontal, diffuse horizontal and reflected components of solar power. The diffuse horizontal component includes reflected irradiance that has been scattered by clouds and backscattered by the atmosphere onto the surface. Reflected irradiation refers to solar power typically reflected by the ground.
Global tilted irradiance (GTI)	Irradiance received by a surface with a defined tilt and orientation (azimuth). It is the sum of direct, diffuse and reflected radiation.

Term	Meaning
Ground mounted	A solar system mounted on the ground, either by driven piles or concrete pads, depending on the soil.
Inverter	A device used to convert direct current to alternating current. In this report it refers to a PV inverter, which specifically interfaces to PV modules to maximise energy capture from the modules (using maximum power point tracking), and to the electricity grid where it provides certain protection functions such as anti-islanding, ability to ride-through voltage and frequency deviations, cut-off at sustained over or under voltages, and advanced power quality response for voltage control.
Inverter loading ratio	The ratio of nominal PV array capacity (Wp) to inverter capacity (W). An inverter loading ratio of greater than one (where the array of modules is oversized) results in the inverter being loaded closer to its capacity for a greater percentage of the day. As a result, more of the sun's energy is collected throughout a day.
Irradiance	In this report irradiance refers to solar terrestrial irradiance. This is the power from the sun landing on the Earth's surface at each point in time, measured in watts per square metre (W/m^2).
Irradiation	Cumulative energy from the sun landing on the Earth's surface over a period of time, measured in watt-hours per square metre per annum for example.
Land use efficiency	The capacity of a ground mounted solar system per square metre, effectively giving the land area required for a system of given capacity. Measured in Wp-ac/m^2.
Learning curve	Also known as the 'learning rate' or 'experience curve', gives the reduction in a product cost for each doubling in production of that product.
Location factor	The ratio of nodal spot price at a GXP location on the transmission grid to nodal spot price at a reference node.
Longlist	A list of *all* potential utility-scale solar systems that have an acceptable rate of return, after considering the cost of transmission or sub-transmission to the nearest GXP or zone-substation with sufficient capacity to connect a solar system of the given capacity. However, total GXP, zone-substation or MV line capacity from all potentially connected solar systems is not considered. This provides information on all economically viable solar potential by location, capacity and timing.
Module	A PV module (sometimes called a panel), comprising multiple PV solar cells with contacts and wiring connecting the cells in series, able to be interfaced to external wiring to connect to other modules (making an array) and an inverter/inverters. The multiple cells and wiring are packaged in a support structure to provide mechanical strength and anti-reflective coating for mounting on either a roof or ground mounting system. Packaging also protects from external pollutants (dust and bird soiling) and projectiles such as rain and hail. Modules are mass produced and typically range in size from around 250 Wp to 400 Wp. Mass production has led to a commodity market for modules with prices ($/Wp) monitored and reported with other energy commodities.

Term	Meaning
Mono-crystalline PV	Also called single-crystalline. The manufacture of mono-crystalline silicon is such that a crystal of the same type is reproduced. Efficiency of a mono-crystalline cell is typically slightly higher than multi-crystalline, but manufacturing cost has traditionally been higher. See Schwartfeger & Miller, 2015.
Multi-crystalline PV	Also called poly-crystalline. The manufacture of multi-crystalline cells is such that a block of silicon crystal of varying structure is formed. See Schwartfeger & Miller, 2015.
Multi-junction	The use of two or more different PV cells, each responsive to a different portion of the sun's spectrum, to produce electric current. Multi-junction devices achieve a higher total conversion efficiency than first-generation single junction PV cells because they can convert more of the sun's spectrum of light into electrical energy. They are a third-generation solar technology.
N-1 and N	Refers to the level of redundancy at a substation or electrical installation. N-1 means that supply is maintained despite the loss of an asset, such as a transformer or transmission/sub-transmission line fault, or removal for maintenance. N means that supply is dependent on single assets, and supply will be lost if one of those assets fails or is taken out of service.
Nodal spot price	The half-hourly price at a GXP location on the transmission grid used to buy and sell electrical energy (with units of $/MWh).
Organics	A relatively new third-generation solar technology.
Perovskites	A relatively new fourth-generation solar technology, not in production and still subject to instability, but showing promise in rapidly increasing cell efficiencies since its discovery.
Photovoltaic (PV)	Photovoltaics is the process of converting light into electricity using solar cells, made of materials that exhibit the photoelectric effect. This causes them to absorb light and release electrons. The capture of the free electrons in the treated semi-conducting material gives rise to an electric current, which can in turn provide electrical energy. The effectiveness of a PV cell is limited to a narrow part of the sun's spectrum.
Populated area	One of 576 populated areas in the North and South Islands of New Zealand, including major, large, medium and small urban centres and rural settlements. Areas range in size from 0.1 square kilometres to over 600 square kilometres. Populations range from about 100 people to about 1.7 million people.
Population centre	Same definition as populated area.
Price scenarios	The scenarios used to determine PV forecasts, with each scenario giving combinations of reference node electricity price, general price inflation, electricity price inflation, wage inflation, discount rate and required rate of return of a PV system.
Production Scenario 0	The scenario of PV capital costs based on worldwide PV module production continuing to grow at the same rate as that from 2010 to 2018 until 2024, after which growth begins to slow.
Production Scenario 1	The scenario of PV capital costs based on worldwide PV module production beginning to slow from 2019.
Reference node	A GXP location on the transmission grid used to determine location factors. In this study the Benmore GXP is used as the reference node.

Term	Meaning
Second-generation	Refers to solar generating technology that has entered production and the supply chain as a competing technology more recently than the first-generation, although it has a much lower production capacity (Schwartfeger & Miller 2015).
Shortlist	A list of potential utility-scale PV solar systems with the *highest* rate of return that are within GXP, zone sub-station or MV line capacity. The shortlist leads directly to a forecast of PV solar.
Single-axis tracking	A PV system where the modules are mounted on control equipment that tracks the sun's position from east to west across each day (also referred to as azimuth tracking).
Spectral mismatch	The mismatch between the spectrum of light used to assess PV cell performance under ideal test conditions and the spectrum of light from the sun incident on a PV module. This is relevant as a PV module converts sunlight energy from a narrow frequency range (spectrum) into energy.
Spur line	A line built from a utility-scale solar system to the nearest medium voltage distribution line.
Thin film solar cell	A second-generation PV technology which is typically flexible – able to be bent over a surface. Thin film makes up approximately 10% of worldwide PV sales.
Third- or fourth-generation	Refers to very new solar generating technology that is still in research and development or possibly at small-scale manufacture, but not in mass production (Schwartfeger & Miller 2015).
Zone-substation	A substation owned and operated by an electricity distribution business, typically connected by 33 kV or 66 kV sub-transmission lines, and usually with 11 kV or 22 kV distribution feeders distributing electrical energy close to consumers.

Abbreviations (acronyms and units)

Abbreviation/acronym/unit	Meaning
$/MWh	The price or cost of electrical energy (dollars per MWh unit of energy).
$/Wp	Price (in the given currency) per peak power output of a PV module. Currency used in this report is NZD.
$/Wp-ac	Price (in the given currency) per peak power output of a PV system at the AC side of a solar system (i.e. it includes all components including the inverter). Currency used in this report is NZD.
1 km x 1 km	1 kilometre by 1 kilometre, used to refer to the dimensions of a land cell.
AC	Alternating current. In this report this usually refers to the transmission or distribution network side of a grid-connected solar system, connected via an inverter.
BOS	Balance of system, refers to components in addition to the PV modules and inverter that make up a PV system, such as wiring, ducting, and structural mounting components.
CdTe	Cadmium telluride
CIGS	Copper indium gallium selenide
DC	Direct current. In this report this usually refers to the PV modules (array) side of a solar system, connected to an inverter/inverters.
EDGS	Electricity demand and generation scenarios
EPC	Engineering, procurement and construction of a utility-scale PV system.
GIP	Grid injection point
GWh	Electrical energy in gigawatt hours, given as the average power flowing over an hour.
GWp	GWp is the peak power in gigawatts that can be produced by a solar energy system, under ideal sunlight and temperature conditions. The actual power produced will vary substantially from the peak power as sunlight (irradiation) varies and module efficiency varies with temperature, shading, surface cleanliness, and degradation over time. Note that the report, and some quoted reports such as those by IRENA, sometimes refers to PV capacity in GW, MW, kW or W without the ‘p’ subscript; the ‘p’ subscript is implied in these cases.
GXP	Grid exit point
ha	Hectare
HV	High voltage (usually 33 kV or 66 kV sub-transmission or 110 kV or 220 kV transmission).
HVDC	High voltage direct current, and in this report refers to the inter-island transmission link between Benmore Power Station located in the Waitaki Valley and Haywards substation north of Wellington.
IEA	International Energy Agency
IRENA	International Renewable Energy Association
IRR	Internal rate of return
km	Kilometre
km x km	Same definition as 1 km x 1 km
kV	Kilovolts
kVA	Kilovolt-Amps
kWh	Electrical energy in kilowatt hours.

Abbreviation/acronym/unit	Meaning
kWp	Peak power in kilo watts of a solar energy system (see GWp).
LBNL	Lawrence Berkeley National Laboratory (U.S.A.)
LCDB	Land cover database v5.0 of mainland New Zealand, developed by Landcare Research.
LCOE	Levelised cost of energy
LINZ	Land Information New Zealand
LRMC	Long run marginal cost
LV	Low voltage
MBIE	Ministry of Business, Innovation and Employment
MV	Medium voltage (usually 11 kV, possibly 22 kV)
MWh	Electrical energy in megawatt hours.
MWp	Peak power in megawatts of a solar energy system (see GWp).
NIWA	National Institute of Water and Atmospheric Research
NPV	Net present value
NREL	National Renewable Energy Laboratory (U.S.A.)
PV	Photovoltaic
RBNZ	Reserve Bank of New Zealand
SRTM	Shuttle Radar Topography Mission
TWh	Electrical energy in terawatt hours.
V	Volts
Wp	Peak power in watts of a solar energy system (see GWp).
Wp-ac/m^2	Wp-ac refers to the peak capacity on the AC (electricity grid connection) side of a utility-scale solar system, noting that the DC capacity may be higher from over sizing array capacity (an inverter loading ratio above 1). Wp-ac/m^2, watts peak per square metre, gives the units of land use efficiency of a utility-scale solar system.

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Disclaimer

This report gives forecasts of transmission grid and electricity distribution network connected utility-scale photovoltaic solar capacity and energy using a model developed by the author and described herein. The forecast results and model description are supplied in good faith and reflect the expertise and experience of the author. The model is subject to assumptions and limitations referred to in the description. Furthermore, the model is subject to many inputs and assumptions provided by MBIE and others, including scenario parameters and international projections. Importantly, it uses the configuration and development of the transmission grid, electricity distribution networks, load and generation at the time of writing. Any reliance on the forecasts is a matter for the recipient's own commercial judgement, taking into account the stated inputs, assumptions and limitations. AMCL accepts no responsibility for any loss by any person acting or otherwise as a result of reliance on the forecasts provided in this report.

Executive Summary

This study contributes to the Ministry of Business, Innovation and Employment's development of the Electricity Demand and Generation Scenarios (EDGS). It does so by providing a forecast of potential utility-scale photovoltaic (PV) solar electricity generation in New Zealand, with accompanying detailed information such as size, location, and cost of each project. This provides an evidence base to inform energy sector and climate change policy, infrastructure providers, and the wider modelling community.

For a given location and design, utility-scale PV solar rate of return is most sensitive to electricity price and capital cost to build. From the absence of utility-scale solar development in New Zealand to date, the combination of electricity price and capital cost appear to have not guaranteed a suitable rate of return as yet. However, as the forecasts in this report show, capital costs for utility-scale solar are reducing and are now close to a point where rate of return becomes acceptable to consider building such plant. The forecasts also show that once that point is reached, the development of utility-scale solar could be extensive and rapid.

Utility-scale solar capital cost reduction is fuelled by a substantial worldwide PV industry that in 2018 produced and installed 103 GWp of solar modules – enough to meet New Zealand's annual electricity requirement by more than 3 ½ times.[1] This industry has grown substantially in the past 15 years and is expected to continue to grow according to International Renewable Energy Agency (IRENA) and International Energy Agency (IEA) forecasts. As the industry continues to grow, it improves production and installation techniques, leading to a lower module and system capital cost. Indeed, dramatic cost reductions are predicted by IRENA.

The exact timing of utility-scale solar development in New Zealand depends on several other factors in addition to electricity price and capital cost. These include:

- Location - irradiance varies substantially depending on location, mainly due to weather conditions but also due to latitude and topographic shading, and land availability in those locations (while there is ample land suitable for utility-scale solar systems, its availability will be constrained by alternative uses).
- Utility-scale solar system design - it is now economic to incorporate tracking systems to track the sun throughout a day, and to over-size module capacity to improve the inverter loading ratio and offset module degradation, thereby improving system capacity factor.
- Suitable electricity transmission or distribution infrastructure.
- Cost of capital and desired rate of return.

The scenarios investigated in this report illustrate the potential utility-scale solar build outcomes from changes in and optimisation of some of these factors. The modelling approach assumes that

[1] GWp is the peak power in giga watts that can be produced by a solar energy system, under ideal sunlight and temperature conditions. The actual power produced will vary substantially from the peak power as sunlight (irradiation) varies and module efficiency varies with temperature, shading, surface cleanliness, and degradation over time.

utility-scale solar is built if it is economic. This approach does not compare utility-scale solar with other generation technologies, so in that sense it is not a forecast of build, but rather a forecast of potential build. Scenarios were designed to primarily test sensitivity to electricity price and rate of return. The core scenarios, pertaining to results in this Executive Summary, are shown in the table below.

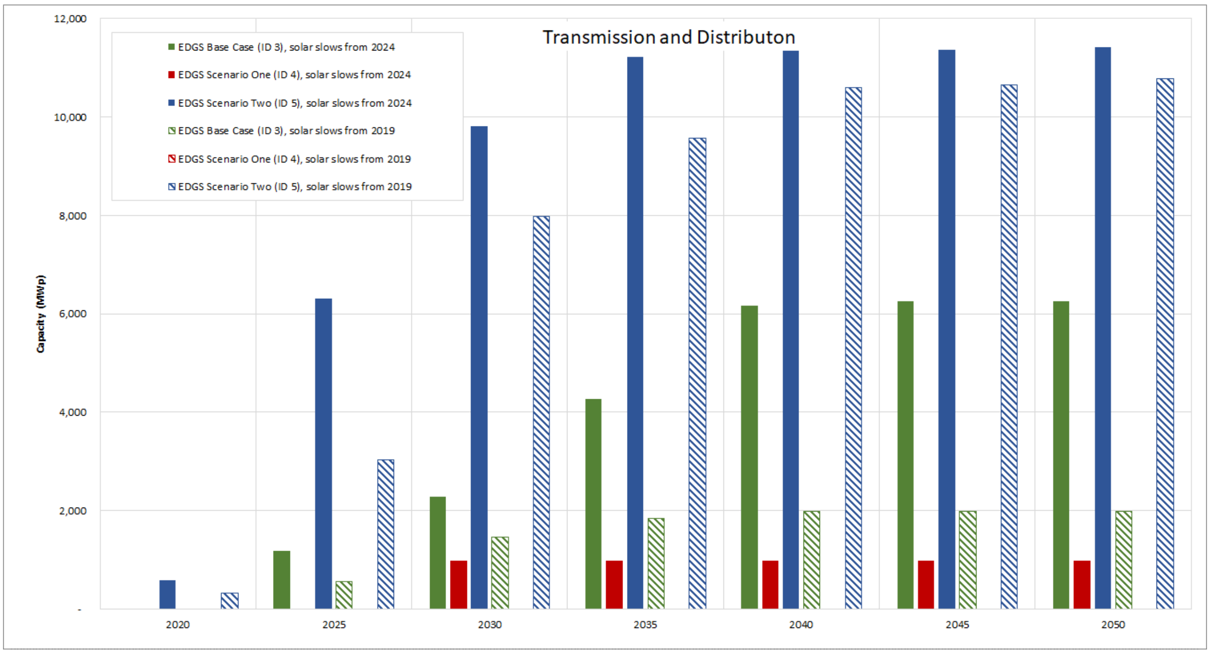
Price scenario parameters for the results shown in this Executive Summary - three core price scenarios consistent with the Ministry of Business, Innovation and Employment's Electricity Demand and Generation Scenarios.

ID	Name	Benmore Average Price (CY2020), $/MWh	General Price Inflation	Electricity price inflation	Land value inflation	O&M price inflation	Wage inflation	Nominal discount rate	Nominal IRR criteria for selecting potential site
3	EDGS Base Case	85	2%	2%	5%	2%	3%	7%	8.5%
4	EDGS Scenario One	85	2%	1%	8%	2%	3%	8%	9.5%
5	EDGS Scenario Two	85	2%	3%	3.5%	2%	3%	5%	6.5%

The rationale for the scenario parameters is explained in detail in the report. Briefly: (i) the 2017 electricity price from the 2019 EDGS scenarios is used with inflation adjustment. This is based on the long run marginal cost of new generation entering the market in the 2019 electricity demand and generation reference scenario; (ii) the Base Case scenario (ID 3) assumes electricity price increases at the same rate as inflation – and therefore the real price remains constant in 2020 dollars, consistent with the wholesale price indicator in the 2019 EDGS scenarios; (iii) land price inflation is set above the average dairy farm land price increases from 1978-2015 of 2.6% per annum; and (iv) the nominal discount rate is assumed to be 7% in the Base Case which is consistent with that used in the wind generation stack update report for EDGS. Since this study is exploratory in nature, parameters chosen for EDGS Scenario One and Two (ID 4 and ID 5) are quite extreme in order to provide a broad range of estimates of the potential solar sites.

Projections of solar capital costs are based on international studies of component cost by utility-scale solar system size, projected production and historical learning curves. Although worldwide solar module production has increased exponentially historically, this analysis assumes that the rate of increase will start to slow sometime in the next 10 years. As a result, capital costs reductions are also expected to slow. Two 'production scenarios' for this effect are included, with the slowing beginning at different years (from 2019 or from 2024). The reason for this is to investigate the forecast sensitivity to slowing worldwide solar production and the slowing of expected capital cost reductions.

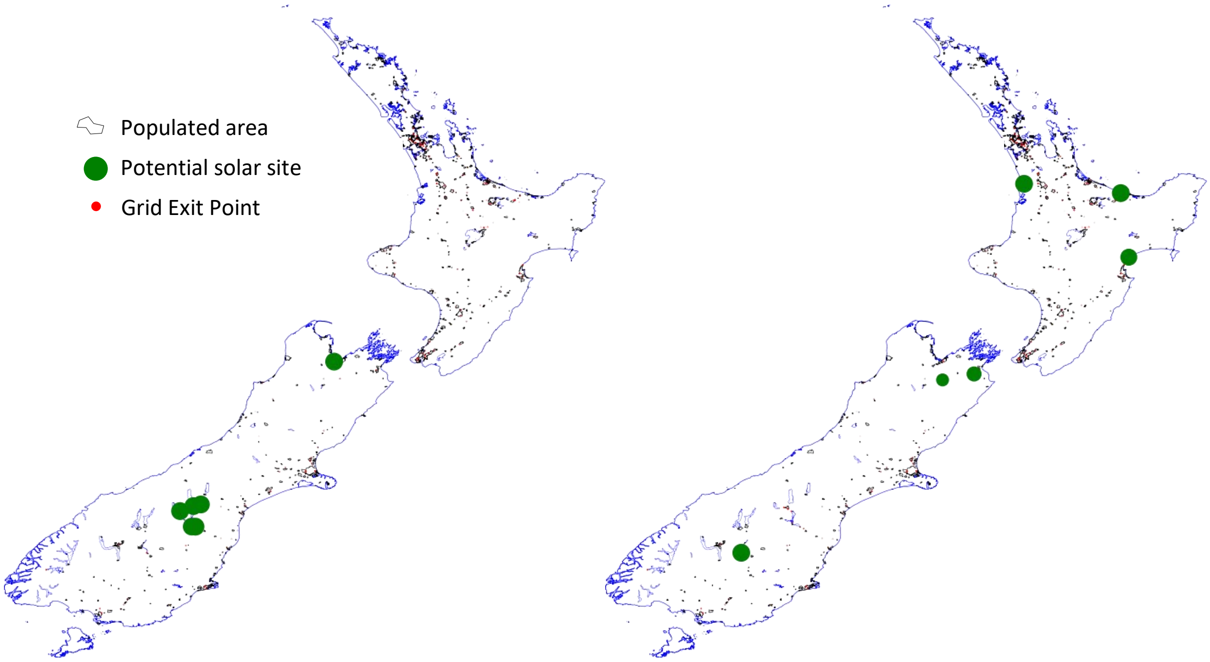
The following chart shows build forecasts for both transmission and distribution connected solar for the three price scenarios in the above table. In the chart the Base Case (solid green bar) requires a rate of return of 8.5% and incorporates strong land price inflation and medium electricity price inflation. Scenario One (solid red bar) requires a rate of return of 9.5%, has high land price inflation and low electricity price inflation. The Scenario Two (solid blue bar) requires a rate of return of 6.5% with moderate land price inflation and high electricity price inflation. The patterned bars are the same scenarios but with worldwide PV module production slowing from 2019. In all forecasts the capacity of distribution connected solar is about 5-15% of transmission connected solar.



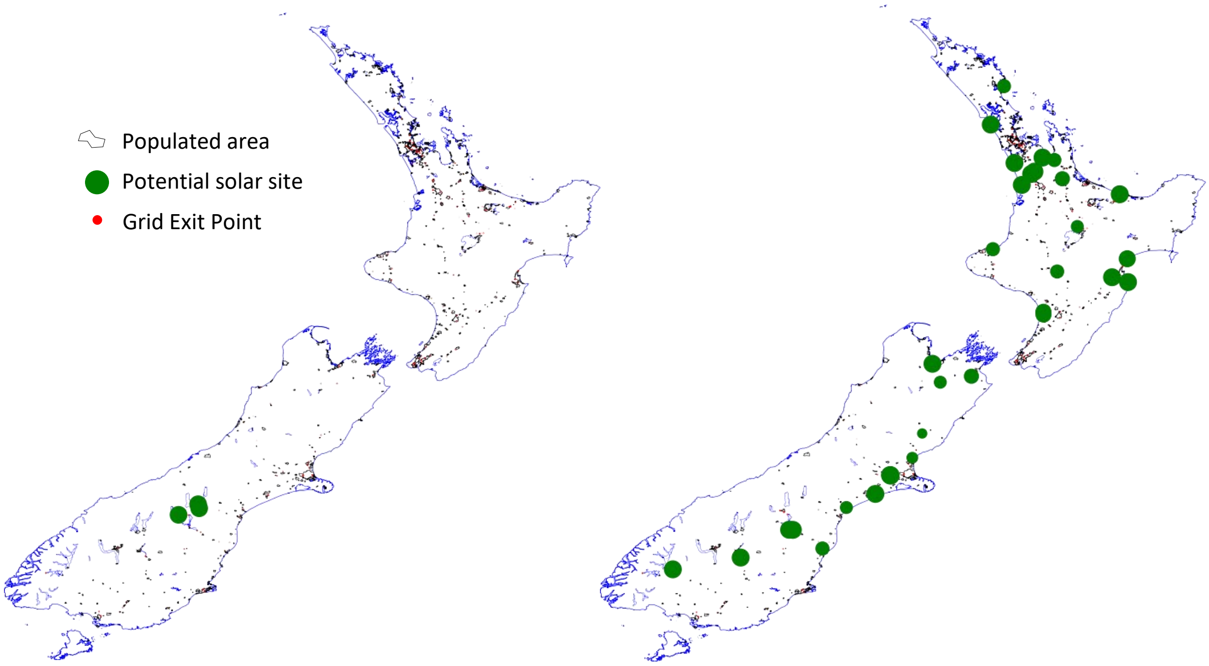
Transmission and distribution connected cumulative utility-scale solar system capacity. In all forecasts the capacity of distribution connected solar is about 5-15% of transmission connected solar.

As shown in this chart, the potential build differs significantly between scenarios, illustrating the sensitivity of utility-scale solar build to the economic assumptions. Nevertheless, it is worth noting that if and when utility-scale solar does become economically feasible, growth could be rapid, with major development possible in the space of 5-10 years.

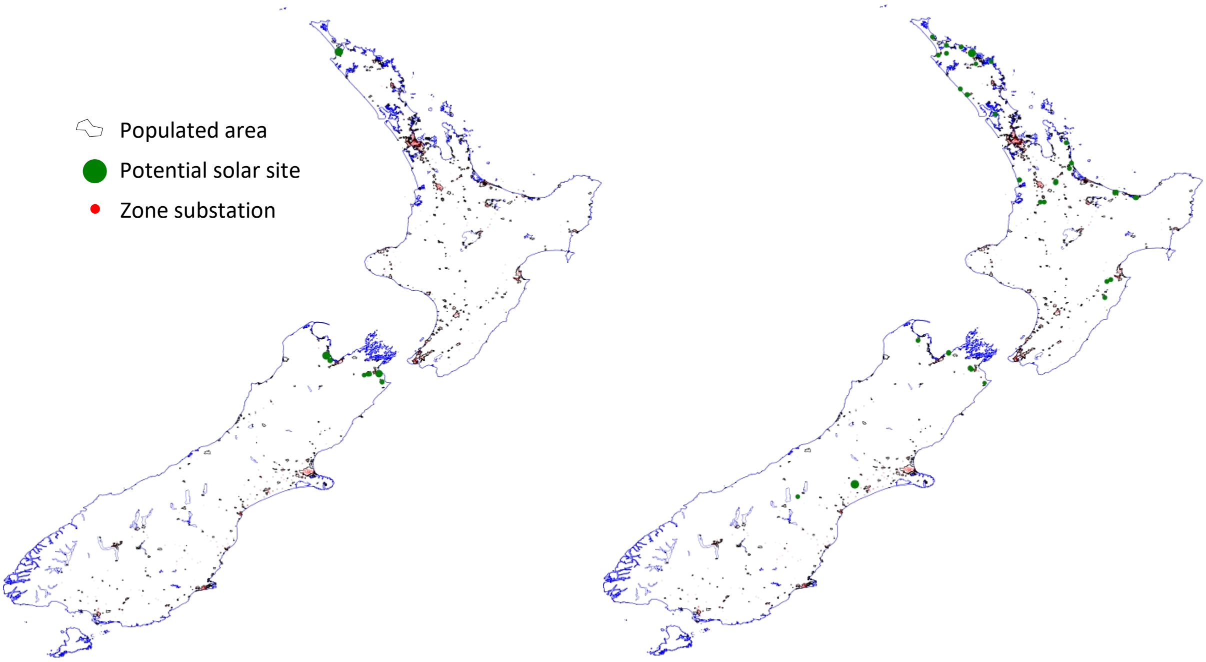
The approach used has considered utility-scale solar plant on a site-by-site basis, so by its nature has also examined where and when in New Zealand utility-scale solar systems are forecast to locate. This varies slightly between scenarios due to land price and electricity price difference. In general, the first forecast transmission connected utility-scale solar systems are forecast to locate (i.e. become economic) in the Mackenzie District and Tasman District, followed by Marlborough, Waikato, Hawke's Bay, Bay of Plenty and Central Otago as shown below. The first forecast distribution connected utility-scale solar systems locate (i.e. become economic) in the Far North District, Tasman and Marlborough, followed by the Bay of Plenty, Hawke's Bay, Waikato and Canterbury, as shown below.



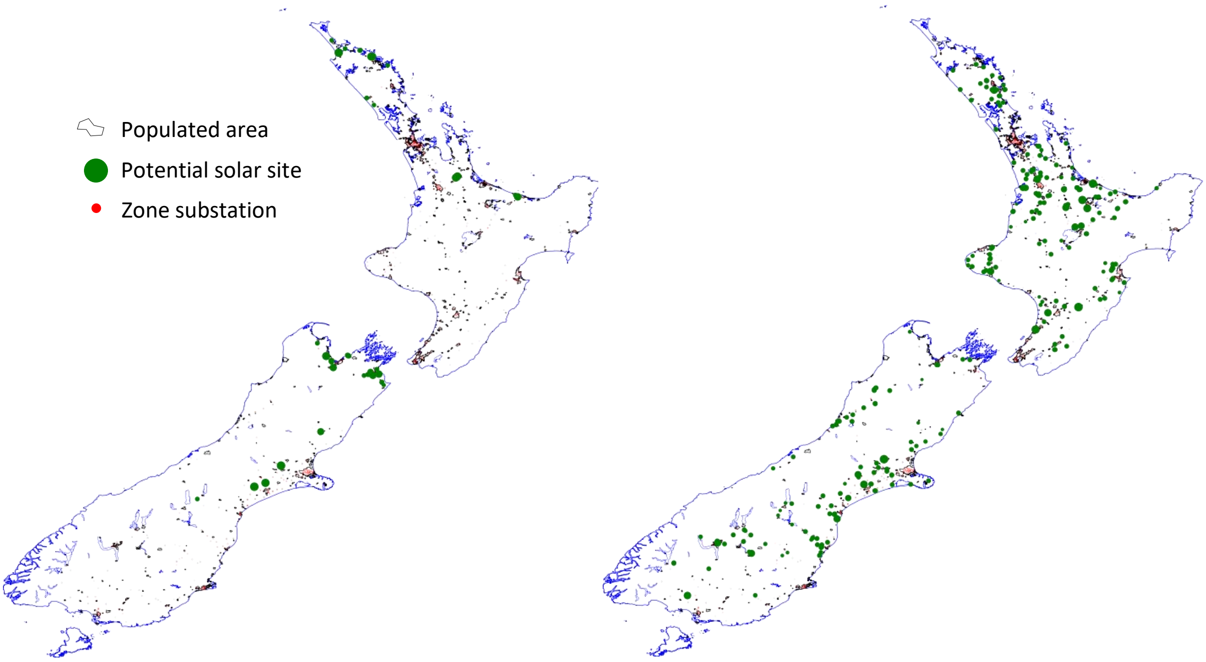
Transmission connected forecast utility-scale solar system locations in 2025 (left) and 2030 (right) EDGS Base Case scenario (the solid green bar of the above chart). This illustrates the areas where transmission connected utility-scale solar systems are most likely to locate first, due to a combination of high solar resource, higher location factors, suitable land at an acceptable price, and transmission grid. Solar capacity is represented by the size of the green dot (largest is 200 MWp).



Transmission connected forecast utility-scale solar system locations in 2020 (left) and 2025 (right) EDGS Scenario Two (the solid blue bar of the above chart). This illustrates the areas where transmission connected utility-scale solar systems are most likely to locate first in this scenario of lower cost of capital. Solar capacity is represented by the size of the green dot (largest is 200 MWp).



Distribution connected forecast utility-scale solar system locations in 2030 (left) and 2035 (right) EDGS Base Case scenario (the solid green bar of the above chart). This illustrates the areas where distribution connected utility-scale solar systems are most likely to locate first, due to a combination of high solar resource, higher location factors, suitable land at an acceptable price, and proximity to distribution network infrastructure with suitable capacity. Solar capacity is represented by the size of the green dots (largest is 20 MWp).



Distribution connected forecast utility-scale solar system locations in 2025 (left) and 2030 (right) EDGS Scenario Two (the solid blue bar of the above chart). This illustrates the areas where distribution connected utility-scale solar systems are most likely to locate first in this scenario of lower cost of capital. Solar capacity is represented by the size of the green dots (largest is 20 MWp).

The forecasts also show very high solar development in some scenarios, even with transmission and distribution capacity constraints accounted for. It may be questionable whether the wider electricity system could accommodate such solar capacity (for example, in terms of technical integration and managing and storing the daily and seasonal solar generation profile). This effect is being observed in Australia now, where there are far more new solar generation plants wanting to connect to the state grids than the distribution and transmission companies can deal with administratively and that the national System Operator is comfortable connecting. However, as mentioned above, a rapid rate of growth when the balance tips towards utility-scale solar systems becoming economic suggests the need for preparedness by network owners and operators.

When considering the forecasts in this report the following should be considered alongside them:

1. Capacity factor of a renewable generator is a particularly important consideration. Capacity factor is the measure of the resource available to a renewable generator, and its efficiency in converting that resource into saleable energy. For this it employs solar generating plant which comes at a considerable cost. Capacity factor is closely related to the solar resource, solar module efficiency and inverter characteristics. As discussed above, utility-scale solar system design can improve capacity factor; this study assumes all solar systems will employ increased inverter loading ratios and single-axis tracking. With these improvements the capacity factors of solar modelled throughout New Zealand range, conservatively, from about 0.12 to 0.20.

2. The forecasts must be viewed in conjunction with possible medium- to long-term electricity infrastructure changes. Infrastructure changes that will permanently increase or lower price and/or location factors are particularly important.

3. The large influx of solar capacity shown in some forecasts may also depress the wholesale electricity price at times when solar is generating, negating the incentive to develop a utility-scale solar project. While the forecasts do incorporate the reduction in location factor at a location from increased generation resulting in lower transmission losses, they do not incorporate the entire wholesale electricity market, and the effect of increased generation on real-time wholesale price. For these reasons, the very high forecast scenarios (the blue bar in the above chart / Scenarios 0, 2, 3, 5 and 8 in the report) are unlikely to eventuate.

4. The rates of return of utility-scale solar projects in other jurisdictions may be greater than what can be achieved in New Zealand. Solar projects in countries with better solar resource, such as Australia, California, the Middle East and northern Africa will produce more energy, potentially increasing rates of return. This is relevant, as the forecasts are based on utility-scale solar projects meeting an acceptable rate of return. For this reason, a range of rates of return are tested in the scenarios.

5. However, as solar development becomes saturated in other countries, solar investors/developers may look to New Zealand for development. Even if those countries are a long way off saturation, increasing solar deployment will drive more module production, reducing PV system prices further and thereby increasing rates of return in New Zealand. As discussed earlier, utility-scale solar forecasts are very sensitive to capital cost.

6. There is also the possibility that the cost of capital will decrease substantially in the near- to medium-term largely as a result of the coronavirus (COVID-19) pandemic declared while this study was being conducted. Consideration was given to adjusting some scenario parameters to account for economic disruption from the pandemic. However, this is a long-term study to 2060 and the parameters were therefore retained. Nevertheless, the report does investigate some of the forecast outcomes that may eventuate in a low cost of capital and electricity price inflation environment. Countering cost of capital reductions could be disruptions to supply chains of solar equipment resulting from the pandemic, possibly increasing its capital cost. While investigations of more recent capital costs show ongoing reductions in PV module and inverter costs, more recent data was not available at the time of writing to understand the impacts from the pandemic.

7. Since many PV components are imported, fluctuations in the New Zealand dollar could change the cost of systems in New Zealand. This may counter reducing rate of return requirements, although other generation technologies are likely to be similarly affected by exchange rate fluctuations.

8. Ongoing advances in other generation technologies, such as wind and geothermal, may see reductions in their capital costs. In turn they will continue to compete with utility-scale solar, and therefore the very large forecasts indicated in this report may not eventuate.

9. The lifespan and analysis of utility-scale solar used in this study was 25 years. This is a conservative assumption, as lifespans of modern modules are more likely to be in the range of 30 years, but they may attract a price premium.

10. The HVDC link transmission charges solely to South Island generators was removed as per the proposed new transmission pricing methodology published by the Electricity Authority in July 2019.

One of the key findings from this study is how rapidly utility-scale solar development could become economic in New Zealand. For example, if all economic utility-scale solar systems were built within the existing grid capacity, there could be several gigawatts of development in the space of 5-10 years. This growth would be fuelled primarily by the exponential growth in module production (a consequence of the large and growing solar industry). Moreover, such rapid growth could begin any time in the next 10 years.

Finally, further investigation of solar forecasts with a lower electricity price inflation combined with a lower cost of capital environment, shows lower overall solar capacity development. Nevertheless, the development may still be rapid and occur in the next 10-15 years.

1. Introduction

The purpose of this study is to contribute to the Ministry of Business, Innovation and Employment's (MBIE's) published data on New Zealand's 'generation stack'. In turn these will contribute to its electricity demand and generation scenarios (EDGS). The generation stack is a detailed list of potential future electricity generation projects in New Zealand covering information such as technology, size, location and cost of each project. This provides an evidence base that informs energy sector and climate change policy, informs infrastructure providers such as Transpower and distributors, and is used by the wider modelling community.

For this study MBIE specifically requested a forecast of utility-scale photovoltaic (PV) solar electricity generation in New Zealand to 2060. The starting point to develop a utility-scale PV solar generation forecast is to forecast utility-scale PV solar capacity, then convert that to energy. In this report utility-scale refers to PV solar generation directly connected to the electricity grid, either via an electricity distribution network or Transpower's high voltage (HV) network. For the purpose of this study utility-scale solar systems of capacity between 1 MW and 200 MW are considered. The systems considered would typically involve dedicated land purchased or be leased for the purpose of solar generation, utilise ground mounted modules, and in this study employ single-axis PV module tracking to maximise energy capture across each day.

The study specifically considers PV solar rather than thermal-solar such as solar concentrator systems that focus the sun's energy to produce steam and drive a turbine. This is because of the widespread production and application of PV solar systems and the lower irradiance conditions in New Zealand. Crystalline-silicon-based photovoltaic solar technology is specifically considered, rather than other technologies such as thin film (commonly referred to as second-generation photovoltaics), again because of the widespread production and application of crystalline-silicon-based PV solar – this report expands on this in more detail in Section 2.6.

The study uses models that convert solar irradiance (power from the sun landing on the Earth's surface at each point in time, measured in watts per square metre) to utility-scale solar output in watts. This is required over a time span of a year to understand annual energy generation from a solar system. Models developed by the author and associates are used for this assessment. Solar irradiance does vary from year-to-year, depending on cloud cover for example. Hence typical meteorological conditions are used in assessing irradiance. No forecast of changing irradiance is made, as might result from a changing climate.

Also excluded from this study is the analysis of integration of solar into the broader electrical power generation and transmission system and energy system (other than some technical and capacity constraints of the existing grid). For example, excluded are: analysis of all generation options in the same model with pricing implications; and electricity system security of supply with short- and long-term implications as the generation mix changes towards solar. Modelling of these would expand the scope considerably. Moreover, this study provides an input to future modelling of this nature.

This report is divided into two sections. The first section describes the model developed for forecasting utility-scale solar capacity by time and location. The description identifies input parameters to which the model output, and therefore forecast, is sensitive, and how these parameters were determined or are used in the model. This section also describes the operation of the model to identify, optimise and select potential utility-scale solar system sites for distribution and transmission connected systems. The model relies on various other models developed by the author and associate, which are documented in separate ‘commercial in confidence’ design notes. The second section presents and discusses forecasts of utility-scale solar capacity and generation resulting from the model.

2. Solar Forecast Model

One of the challenges in forecasting utility-scale solar uptake in New Zealand is the absence of any built schemes from which to draw insights and to benchmark potential forecast schemes against. When the research for this forecast started in late 2019 there was at least one officially announced scheme of 26 MW capacity at the Marsden Point Oil Refinery (Energy News, 2019), and a few potential schemes known to the author. During the research, Genesis Energy announced they were in discussions with a developer to develop a 300 MW solar farm in the Waikato (Energy News, 2020). However, no utility-scale solar systems have been built and are operational in New Zealand. There are obviously many schemes in other countries, but the economic incentives, electricity markets and electricity prices and solar irradiance in those countries are quite different to New Zealand's.

Given that there are no utility-scale solar installations in New Zealand to date, and due to the scarcity of information about utility-scale solar in New Zealand, it was proposed to consider the problem using a combined land use, solar resource, economic and grid capacity approach. This would consider suitable land types throughout New Zealand and the solar irradiance and utility-scale solar system output at each location. In addition, it would consider the main inputs to solar economics and assume that investors will make decisions based on acceptable rates of return. It would also consider proximity to electricity grid infrastructure (both transmission and distribution) and its capacity to connect PV solar. By default, the distribution model would also consider proximity to roading infrastructure. From that, a *shortlist* of potential utility-scale PV solar systems with the highest rate of return that are within grid capacity would be developed. The shortlist would lead directly to a forecast of PV solar. In addition, the model would consider PV solar potential using just a land-use, solar irradiance/ utility-scale solar system output and economic model, without grid connection constraints. The output of this would provide a *longlist* of potential utility-scale solar systems, and thereby provide information on all economically viable solar potential by location, capacity and timing.

2.1 Model construction and review of other modelling worldwide

To develop such a model the many components that feed into the economics of a solar scheme had to be deconstructed, then assembled into the single model. The forecast would inherently rely on: solar resource and utility-scale solar system generation by location; suitable land type, its location, and land values; wholesale electricity price; PV system capital costs and new or appropriate solar technology; operating and maintenance costs; transmission or distribution connection costs; and forecasts of inputs, such as cost of capital. Therefore, the forecast would need to give a range to accommodate uncertainties in these inputs.

A starting point was to assess what had been done elsewhere in the world. Studies examining land availability and suitability for solar and potential uptake have been undertaken previously. One such study is that by Hernandez et al. (Hernandez, Hoffacker, & Field, 2015). Hernandez et al.'s study makes a useful assessment of the potential PV solar uptake in California, U.S.A. However, it uses data specific to the U.S.A. which makes it difficult to apply to New Zealand. Moreover, it only goes as far as assessing the potential based on land type. It considers neither the economic potential nor grid capacity to connect potential utility-scale solar systems. Another study by authors from the National Renewable Energy Laboratory (NREL) (Ong, Campbell, Denholm, Margolis, & Heath, 2013) also investigated land use requirements for ground mounted PV solar and solar concentrators. This study was also U.S.A. based and only assessed land use requirements. Both studies did provide guidance on land use efficiency that should be used in this forecast study, with both broadly agreeing on about 35 Wp-ac/m^2 land use efficiency after taking into account tracking equipment, access roads, inverter equipment and placement and terrain to avoid shading.[2] A further study that investigated land-use is that undertaken by Wu et al. (Wu, Torn, & Williams, 2015). However, Wu et al.'s study does not investigate the economics of PV solar either, nor the transmission grid capacity to connect PV solar.

One other study from Spain (Martin-Chivelet, 2016) investigates both PV potential and land use but concentrates on roof-top solar. New Zealand specific research has already been undertaken on solar resource and conversion to electrical energy, with proprietary models used in this study. Greenpeace has also commissioned studies in Spain on renewable potential of the Iberian Peninsula, documented by Dominguez-Bravo et al. (Dominguez-Bravo, Garcia-Casals, & Pinedo-Pascua, 2007). However, like the U.S.A. studies, these considered land type but neither the economics nor grid capacity to connect potential.

Numerous studies that investigate technical aspects of integrating PV solar into electricity grids have been undertaken. One such study that also incorporates a geographical component in terms of location connecting to the Californian electricity network is that by Tabone et al. (Tabone, Goebel, & Gallaway, 2016). Such technical investigations would be necessary in siting PV plant in New Zealand. They are implicitly required for distribution connected PV solar through Part 6 of the Electricity Industry Participation Code 2010, and extensive studies would be expected for transmission connected PV solar. However, it does highlight an area of further investigation required beyond this study, which only investigates grid connection from a capacity point of view. That is of grid stability if, for example, grid connected solar was to cluster in an area. While Transpower has undertaken studies, mainly with rooftop solar, the results of this study will provide insights and timing needs for further studies, as it will identify areas where there is particularly strong utility-scale solar potential and will give an indication of possible uptake by time. Another area of further investigation is how electricity supply reliability would be maintained if there was a large development of solar generation in New Zealand, in terms of seasonal and annual solar irradiation variability and interaction with other generation and storage. Again, this study will shed light on this through providing utility-scale solar forecasts.

2.2 Land information resources unique to Aotearoa New Zealand and model inputs

Developing a land-use based model for New Zealand required insights into New Zealand land suitability. A review of information available identified the 'land cover database v5.0 of mainland

[2] Wp-ac refers to the peak capacity on the AC (electricity grid connection) side of a utility-scale solar system, noting that the DC capacity may be higher from over sizing array capacity (an inverter loading ratio above 1). Wp-ac/m^2, watts peak per square metre, gives the units of land use efficiency of a utility-scale solar system.

New Zealand' (LCDB), sourced from the Land Resource Information System (LRIS) portal and developed by Landcare Research. This provides a set of vectors in a shapefile, which were converted into a grid of km x km cells (267,535 cells in all) that cover New Zealand (using the NZTM 2000 projection). The LCDB gives the proportion of 34 different land types, which after the conversion described give the proportion within each cell. From this, land suitable for utility-scale solar systems could be identified. Combined with proprietary utility-scale solar system models that use global-horizontal irradiance data specifically covering New Zealand, the solar generation potential from that land could then be determined. Combining that with electricity prices closest to the land could then give an indication of the revenue potential of a system at each cell of suitable land. This gives a key element of an economic model: the revenue potential.

The other key element of an economic model is the cost, both initial investment and ongoing. The initial investment in a utility-scale solar system involves the land purchase, acquiring and constructing the solar generating plant and building transmission or distribution to the appropriate electricity transmission or distribution network. Ongoing costs involve annual operation and maintenance of the PV solar generating plant, annual operation and maintenance of the transmission or distribution interconnection assets and annual tax costs. These are identified in the model represented conceptually in Figure 1.

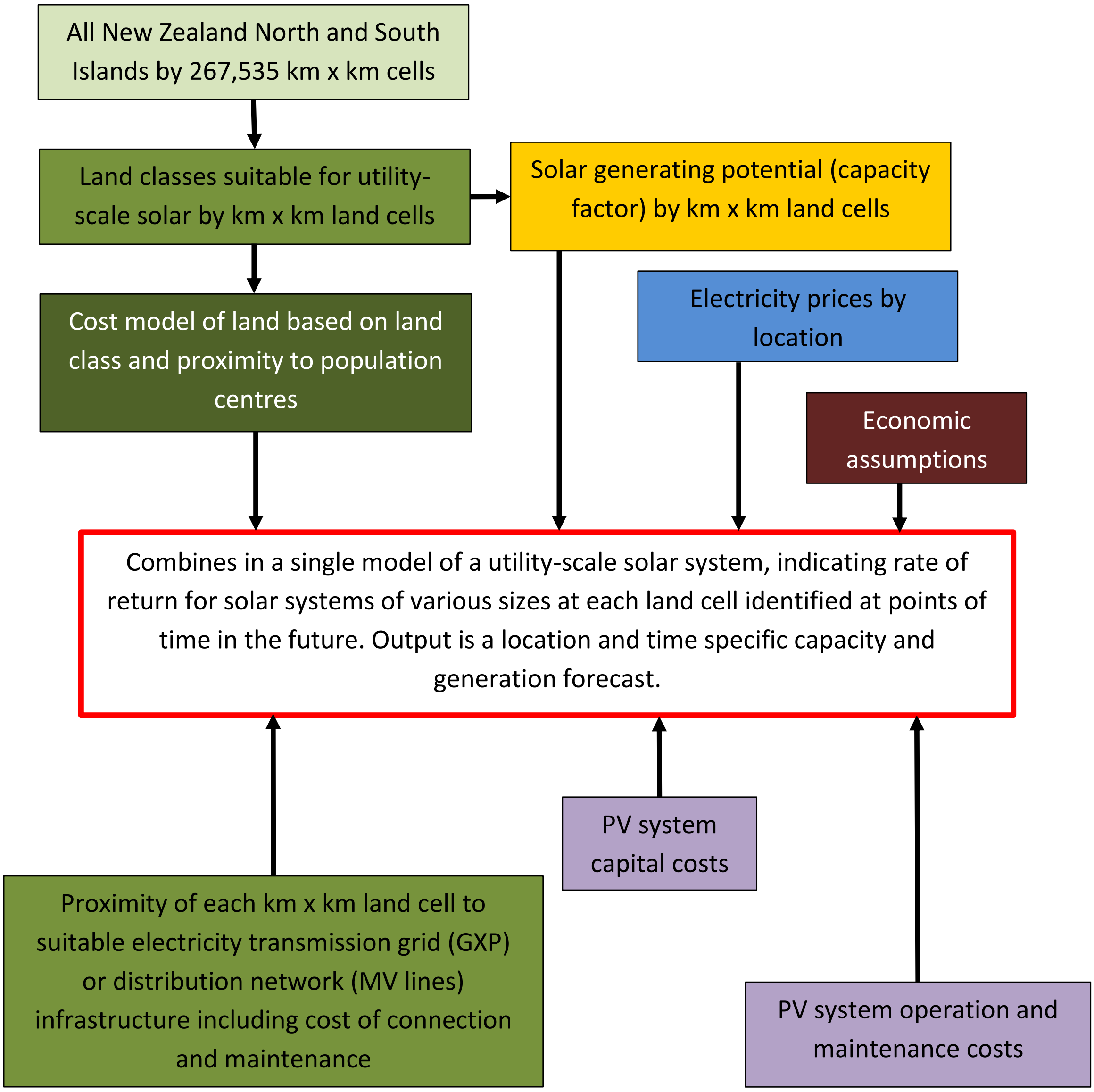


Figure 1: Conceptual model employed in this study to develop utility-scale PV solar forecasts.

2.3 Search for suitable utility-scale solar sites

Essentially the solar forecast model depicted in Figure 1 acts as a filter with multiple stages, beginning with the entire country and progressively filtering it to a set of potential utility-scale solar systems that could be realised. From this a forecast is developed. This process is depicted in Figure 2.

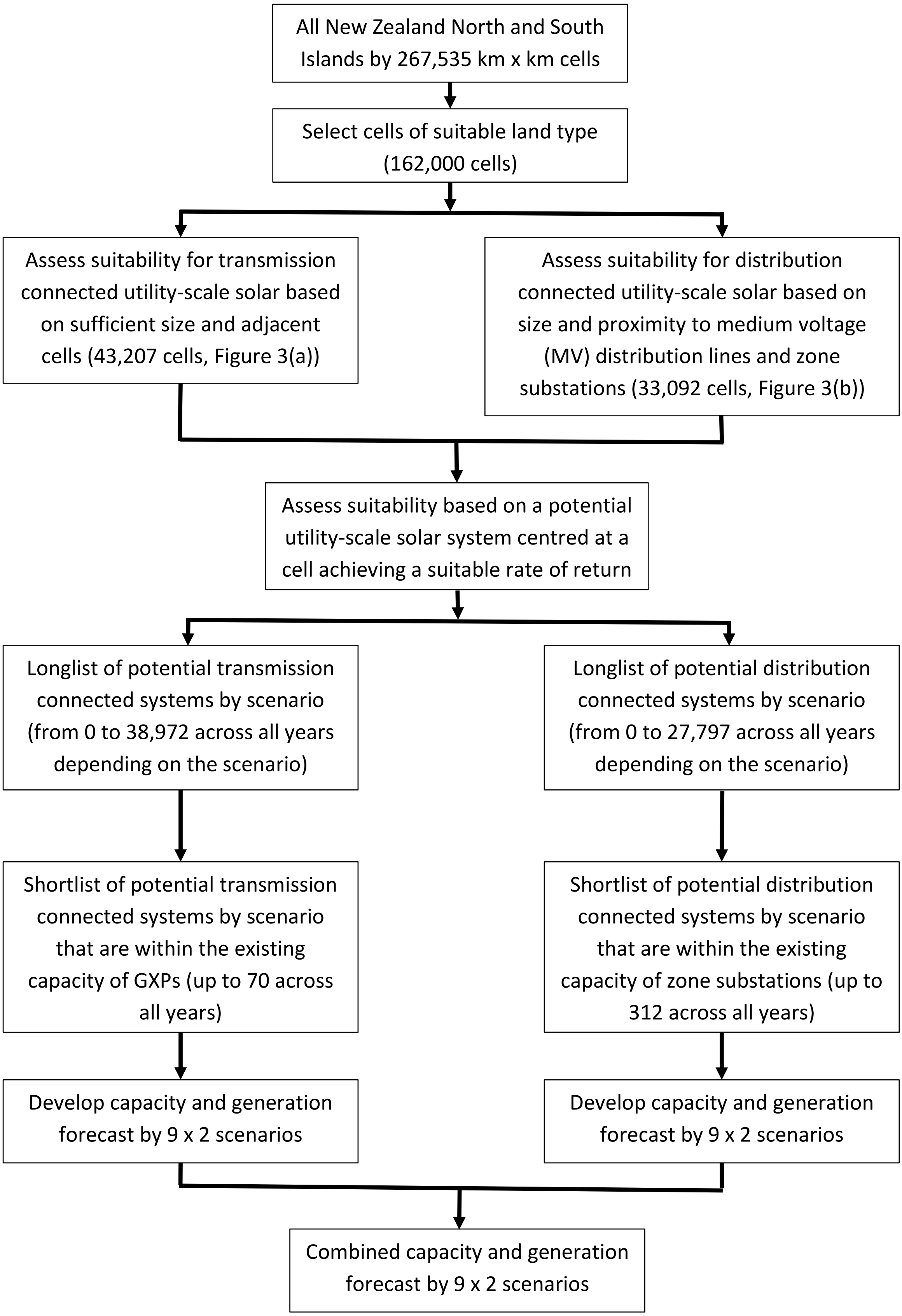


Figure 2: The overarching search for potential utility-scale solar systems from which to develop a capacity and energy forecast.

The initial part of the search, that of selecting cells of suitable land type, selects cells with just three land classes:

- High Producing Exotic Grassland;
- Low Producing Grassland; and
- Depleted Grassland.

The above filter eliminates most other land types in the LCDB from consideration for utility-scale solar. A full list can be found in the LCDB documentation, and as a summary it eliminates:

- forests (exotic and indigenous), deciduous hardwoods, harvested forest, broadleaved indigenous hardwoods, manuka and/or kanuka, matagouri or grey scrub;
- flax- and fern-land, tall tussock grassland, rivers, lakes, ponds and estuaries, freshwater vegetation, saline vegetation, mangrove;
- sub alpine shrubland, mixed exotic shrubland, alpine grass/herbfield, permanent snow and ice;
- short-rotation cropland, orchards, vineyards or other perennial crops; and
- urban parkland, built up areas, transport infrastructure, surface mines or dumps, sand or gravel.

In doing so it also eliminates land under Department of Conservation administration.

The next part of the search treats potential transmission and distribution connected utility-scale solar separately as described below.

2.3.1 Transmission connected utility-scale solar system search

For transmission connected solar each cell must have a combination of at least 95% of any of the above three land classes. Since a 1 km x 1 km cell can host up to a 35 MW of solar, based on the land use efficiency discussed previously, adjacent cells are combined until a capacity of 200 MW can be achieved. Land cost and capacity factors are weighted based on land type, cost and solar capacity factor to form a combined solar project cost, capacity factor and capacity. A procedure also prevents any overlapping solar projects. The set of potential transmission connected solar sites from this search is shown in Figure 3(a).

Selection of a suitable transmission grid exit point (GXP) to connect a solar system to is based on the closest GXP with sufficient import capacity. This may involve a longer transmission line to connect to a GXP that is further away, which is considered a proxy for upgrading the transmission network. While GXP import capacity is considered at this stage, GXP import capacity is not immediately used to limit the number of solar systems. This allows development of a longlist of potential solar system sites, which is of interest to understand potential for solar in an area. A shortlist of potential solar projects is then developed for the purpose of forecasting transmission connected solar uptake. The shortlist does consider GXP import capacity.

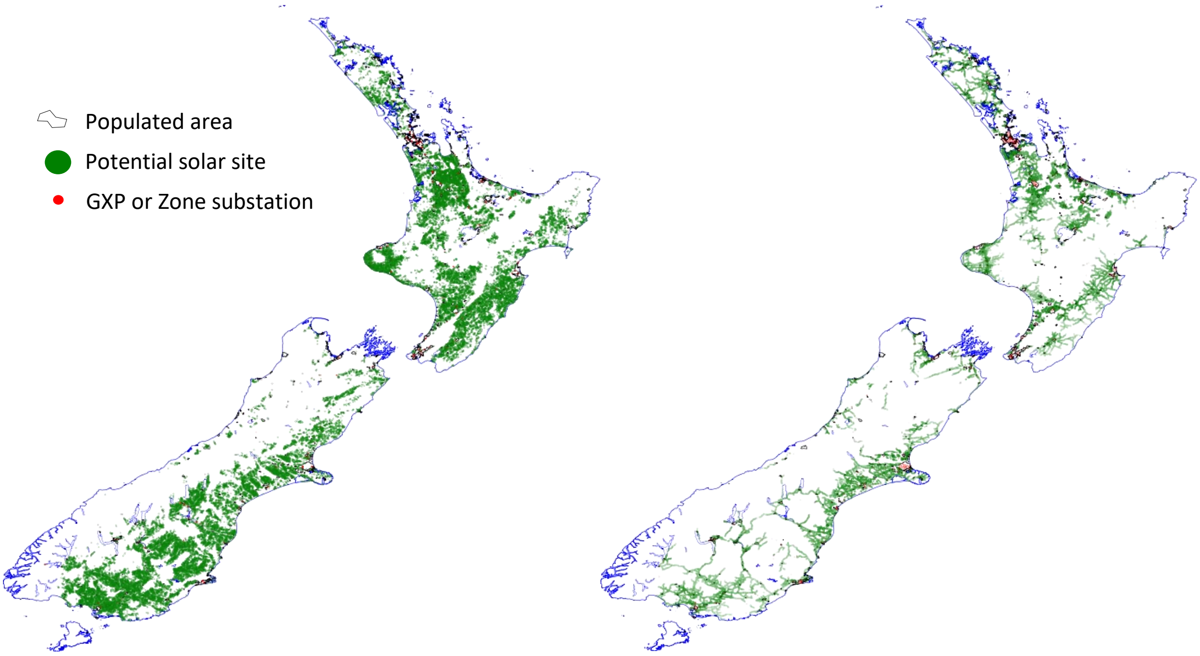
2.3.2 Distribution connected utility-scale solar system search

The search for distribution connected solar begins by identifying all land cells within 2 km of medium voltage (MV) distribution lines (usually 11 kV but possibly 22 kV). The model assumes that most distribution connected utility-scale solar will connect to MV distribution lines (under 5 MW) or connect to the nearest zone substation via a 33 kV sub-transmission line constructed in the road corridor (33 kV with the existing 11 kV feeder underbuilt). In the case of up to 5 MW solar this minimises cost of connection by avoiding dedicated lines and protection equipment to zone substations, and recognises that utility-scale solar capacity is too large to connect at low voltage (the 400 Volt network). In the case of 5-20 MW solar it recognises that a typical 11 kV MV feeder will be capacity constrained above 5 MW, and that a dedicated circuit would therefore be required.

Once land cells within 2 km of MV lines are found, cells with enough of any of the above three land classes to make at least a 1 MW solar system are selected. The capacity of a solar system is capped at 20 MW. A function also reduces solar system capacity the further away it is from the zone substation. This limits capital upgrades necessary to the distribution network.[3] The same function also limits sub-transmission distance for larger solar systems. Land cost is determined by a land cost weighted average based on the area of each land type.

Implementation of this search required information on all MV distribution lines throughout New Zealand. While a database of powerlines was available from the Land Information New Zealand (LINZ) data service, this contained transmission, sub-transmission, MV and low voltage lines, and lines were incomplete in some areas. Transmission could be removed from this database, but sub-transmission and low voltage could not be removed. Further, because it was incomplete, it did not provide full coverage of New Zealand. For this reason, a proxy MV distribution network was created, based on the roading network for which reliable data was available from LINZ. This assumes MV distribution follows most main roads; a reasonable assumption given that MV distribution distributes electricity to properties located on roads and that road corridors are conducive to building distribution infrastructure. From the roading database available from LINZ, all metalled and single lane roads were removed (to remove forestry and other similar remote roads), as well as any road that begins and ends within one of 576 populated areas (to remove the 400 V network that typically follows roads). While not perfect this provided a proxy MV network throughout New Zealand. The set of potential distribution connected solar system sites is shown in Figure 3(b).

[3] In the model distribution connected utility-scale solar capacity is based on the distance between its point of connection to the MV distribution line and the distance to the zone substation, as well as the zone substation capacity. This limits the size of a potential distribution connected solar capacity from between the zone substation firm capacity (for 33 kV connected) or 5 MW (for 11 kV connected) at the zone substation and 10% of the zone substation's firm capacity at 40 km from the zone substation. Where firm capacity is not available or not provided, non-firm capacity is used. The rationale is that load is typically closer to zone substations, leading to lower power flow in the MV line from solar generation. By contrast, the further away from a zone substation, the lower the load at the solar location, and therefore the more requirement for solar power to flow at near full capacity along the MV line. Furthermore, it is likely that smaller cross-sectional area conductor sections or equipment with lower ratings will be used further away from the zone substation where load is lower. This is based on experience from power flow studies of solar installations connected to 11 kV feeders.



(a) *(b)*

Figure 3: (a) Land suitable for transmission grid connected utility-scale solar sites of capacity 20-200 MW (43,207 cells). (b) Land adjacent to proxy medium voltage distribution lines and within appropriate range of zone substations, suitable for potential distribution connected utility-scale solar of capacity 1-20 MW (33,092 cells). These have been reduced from a larger set of suitable sites next to proxy medium voltage distribution by limiting distance from zone substations to no more than 40-60 km (depending on zone substation capacity) and limiting distance from the land cell to the MV distribution line to no more than 2 km.

2.3.3 Selection based on suitable rate of return

For both transmission and distribution, solar system capacity is chosen to maximise net present value (NPV) in any one year, thereby determining the optimal solar system capacity within each year. Optimisation is not performed between years; a solar system selected for the longlist in one year may have a higher NPV in a later year, but the model does not consider this. This approach is considered acceptable in that whenever the estimated rate of return is suitable, an investor will be willing to invest, provided the land is available for purchase. The next section discusses the economic model used to assess rate of return, and the various inputs to it.

2.4 Core economic model

Central to the economic model is a discounted cashflow to determine the NPV of a potential solar system at each location selected, at each year considered and for each scenario. After identifying suitable land, the criteria for selecting a potential solar system to be considered in the forecast is that it generates an acceptable rate of return. The discount rate, or effective cost of capital, used in each scenario is increased by 1.5%. This represents an additional rate of return required to cover the cost of decommissioning an existing investment and the loss of income while establishing the new utility-scale solar investment, as required by MBIE. The discounted cashflow therefore calculates the NPV using the discount rate increased by the 1.5%. Since the internal rate of return (IRR) is equal to this discount rate when the NPV is zero, any potential solar project with an NPV greater than zero meets the IRR criteria for selecting it. The equation giving the NPV used in this model is discussed later in this section.

The use of levelised cost of energy (LCOE) was considered for the model. LCOE is closely related to the NPV calculation, essentially determining an average cost of energy required to give an NPV of zero, and thus an acceptable rate of return. If the energy can be sold for more than this, the generator is viable. Furthermore, LCOE facilitates ranking of generation schemes.

Wholesale electricity is priced by location in New Zealand, with quite wide variations between locations. Solar resource also varies widely throughout New Zealand and there are many potential sites for utility-scale solar across the entirety of New Zealand. Selecting and ranking suitable utility-scale solar sites would require matching the LCOE with prevailing locational electricity prices. Hence, NPV was considered more useful due to the large range of possible locations for utility-scale solar throughout New Zealand, by incorporating electricity price directly. NPV is itself suitable for ranking projects and is used in this model to develop a forecast by location. Nevertheless, LCOE is also calculated and provided in detailed output to enable comparison with other generation technologies.

Either way, an idea of future electricity prices would be required. This was accommodated by considering a reference node price, adjusted by location factors, themselves weighted by local solar generation profile. Scenarios provide reference node prices, thereby providing utility-scale PV solar forecasts by different price scenarios. Further a central scenario provides a reference node price equal to the real long-run marginal cost (LRMC) of the new build entering the electricity market in the EDGS 2019 Reference Scenario in the 2040s. In EDGS 2019 the future path of real LRMC was determined endogenously by a model, taking into account both the supply and demand of the electricity market (MBIE, July 2019, p. 28). However, the future path of real LRMC is highly uncertain and conditional on the assumptions used in EDGS. Therefore, other reference node prices are used in various scenarios, discussed further in Section 2.4.3.

Finally, the rates of return of utility-scale solar projects in other jurisdictions may be higher than what can be achieved in New Zealand. Solar projects in countries with better solar resource, such as Australia, California, the Middle East and northern Africa will produce more energy, thus increasing rates of return. This is relevant, as the model decides whether a solar system has potential for development based on it meeting an acceptable rate of return. For this reason, a range of rates of return are tested in the scenarios. However, as solar development becomes saturated in those countries, developers may look to New Zealand for development. Even if those countries are a long way off saturation, increasing solar deployment will drive more module production, reducing PV system prices further and thereby increase rates of return in New Zealand.

There is also the possibility that cost of capital will decrease substantially in the near- to medium-term largely as a result of the coronavirus (COVID-19) pandemic declared while this study was being conducted. Consideration was given to adjusting some scenario parameters to account for economic disruption from the pandemic. However, this is a long-term study to 2060 and therefore, the parameters were retained. Nevertheless, the results and discussion section does investigate some of the forecast outcomes that may eventuate in a low cost of capital and electricity price inflation environment.

2.4.1 Net present value (NPV) and levelised cost of energy (LCOE) definition

The equation for NPV, for each utility-scale solar system and scenario at each forecast year, is given below. The utility-scale solar system capacity is determined to maximise NPV for each cell, scenario and forecast year, capped by the lesser of 200 MW or the maximum size system that can be developed on the land at the cell and adjacent cells.

$$\begin{aligned} NPV = {} & dcfRevenue - pvInvestment - txInvestment - landInvestment - dcfTxCost \\ & - dcfOMCost - dcfMarketCosts - dcfTax + dcfDepTaxShield \\ & + residualValue \end{aligned}$$

Equation 1

where:

$dcfRevenue$ is the revenue in each year of solar operation considered, discounted to a present value in the forecast year at the required rate of return over the lifespan of the solar system (25 years). Revenue itself is given by price at the solar location ($/MWh) x quantity (MWh). Price at the solar location is determined from a ***reference node price*** ($/MWh) x ***location factor***. The quantity or solar system generation is determined according to its ***capacity*** (MW) x ***capacity factor*** x 8,760.[4] Section 2.5 discusses the revenue calculation, and price and quantity determination.

$pvInvestment$ is the investment in all PV solar equipment including modules, electrical and structural balance of system, engineering, design, procurement, installation, permitting, and contingency, including oversizing of PV modules to account for module degradation. It is determined by ***capital cost*** ($/Wp) x ***capacity*** (MW)[5], discussed in Section 2.6.

[4] With there being 8,760 hours in a year. The utility-scale solar system output calculation also accounts for solar system electrical losses, transmission electrical losses, PV module annual degradation, over-sizing of array capacity to counter module degradation, and capacity factor improvement from module tracking and array oversizing.

[5] With some adjustment for over-sizing of array capacity to counter module degradation and improve capacity factor as well as conversion between units.

$txInvestment$ is the investment in the transmission line to access the most appropriate grid exit point or spur line to the distribution line, discussed in Section 2.7. These are referred to as ***transmission capital costs***.

$landInvestment$ is the investment in sufficient land at one of the land cells identified in Figure 3, including adjacent cells if necessary to make a utility-scale solar system with sufficient capacity. It incorporates ***land cost*** based on land type and proximity to populated centres, as discussed in Section 2.8.

$dcfTxCost$ is the transmission maintenance cost in each year of generation operation considered, discounted to a present value in the forecast year at the required rate of return over the lifespan of the solar system considered, discussed in Section 2.7.

$dcfOMCost$ is the ***operation and maintenance cost*** of the solar system discounted to a present value in the forecast year at the required rate of return over the lifespan of the solar system considered. This is discussed further in Section 2.9.

$dcfMarketCosts$ are the costs associated with trading in the market and ancillary service costs. Trading costs are assumed to be covered by the retailer and ancillary market costs are all assumed to be zero. This is discussed briefly in Section 2.10.

$dcfTax$ is the annual tax cost in each year of generation operation considered, discounted to a present value in the forecast year at the required rate of return over the lifespan of the solar system considered. The annual tax cost is determined from the annual contribution to profit by the solar system, which is the corporate tax rate (28%) multiplied by revenue less annual transmission maintenance and plant operation and maintenance costs.

$dcfDepTaxShield$ is the annual reduction in net profit, and therefore tax, through annual depreciation of the investment in the PV solar plant, $pvInvestment$, in each year of generation operation considered discounted to a present value in the forecast year at the required rate of return over the lifespan of the solar system considered. Annual depreciation is determined according to the $pvInvestment$ less accumulated depreciation multiplied by the solar producing equipment depreciation rate of 16% each year (obtained from Inland Revenue). Transmission investment is also depreciated but land is not depreciated.

$residualValue$ is the value of the solar system assets at the end of the solar system's lifespan. This is considered zero, which is conservative as the land at least is likely to have some value after 25 years.

The required rate of return used to discount the above amounts is given in Table 2. A nominal discount rate and rate of return is used, as it was desired to consider the effect of inflation on various components, particularly wage inflation on PV capital cost as discussed in Section 2.6. Inflation parameters and the reference node price are also given in Table 2.

The equation for LCOE, for each cell and scenario at each forecast year, is given below. The definition of LCOE differs depending on the study (IRENA for example use a different definition). Hence direct comparison with other studies requires caution.

$$LCOE = \frac{pvInvestment + txInvestment + landInvestment + dcfTxCost + dcfOMCost + dcfMarketCosts + dcfTax - dcfDepTaxShield - residualValue}{dcfEnergy}$$

Equation 2

where

$dcfEnergy$ is the energy produced by the solar system in each year discounted to a present value in the forecast year at the discount rate over the lifespan of the solar system considered.

The discount rate used in the discounted cashflow for *all* LCOE parameters is the nominal discount rate given in Table 2, which is 1.5% lower than the required rate of return.

2.4.2 Assessing model sensitivity to parameters

The following sections describe how the various inputs to the economic model, through Equation 1 and depicted in Figure 1, were determined. In researching and assigning the various parameters it was of interest to know those inputs to which NPV was most sensitive. To examine sensitivity of NPV, each parameter of Equation 1 was varied from -20% to 20% of a nominal value, given in Table 1. Table 1 also gives other inputs to the NPV calculation, all of which were held constant as each input parameter was varied.

Table 1: Reference parameters used in assessing the sensitivity of NPV to various inputs.

Solar Farm Parameter	Value	Units
Location factor	1.2	
Capacity factor	0.16	
Reference node price	85	\$/MWh
Capital cost (160 MW)	1.185	\$/Wp-ac
Discount rate	6.5	%
Capacity	160	MW
Operation and maintenance cost	20	\$/kWp per annum
Transmission line build cost	500,000	\$/km
Transmission GXP connection cost	15,000,000	\$
Transformer cost	10,000,000	\$/km
Land use efficiency	35	Wp/m2
Land cost	40,000	\$/ha
Distance to GXP / zone substation	10	km
Life span	25	years
Capacity factor improvement from panel tracking	15	%
Transmission losses	0	% of MW flow per km
Annual PV module degradation	0.8	% per annum
Inverter loading ratio	1.0	

The sensitivity results are given in Figure 4 for a solar system capacity of 160 MW. Evident from the figure is the order of sensitivity, with reference node price, location factor and capacity factor the most sensitive compared to other parameters, and each equally sensitive. The fact that their sensitivity is equal is hardly surprising, given that:

$$revenue = 8{,}760 \times capacity \times capacityFactor \times referenceNodePrice \times locationFactor.$$

An equal percentage variation in capacity factor, reference node price and location factor result in the same change in NPV. Capacity does not appear to have the same effect as numerous other parameters also change with capacity, most notably revenue and capital cost. The reference node price is set via *price scenarios*, with scenarios designed to vary the reference node price and thereby examine the forecast sensitivity to it. Determining capacity factor and location factor parameters is discussed in Section 2.5.

The next parameter that NPV is most sensitive to is the utility-scale solar system capital cost. Utility-scale solar capital costs have been investigated carefully and are discussed in Section 2.6. Two *production scenarios* are used in addition to the price scenarios to examine how capital costs might change in the future as worldwide PV module production changes.

Closely following capital cost is discount rate (required rate of return). The price scenarios also include discount rate scenarios, designed to examine the forecast sensitivity to the future cost of capital.

Finally, transmission capital cost, land cost and operation and maintenance cost are the least sensitive input parameters. However, they are sensitive enough to still warrant careful consideration. They are discussed in Sections 2.7, 2.8 and 2.9 respectively.

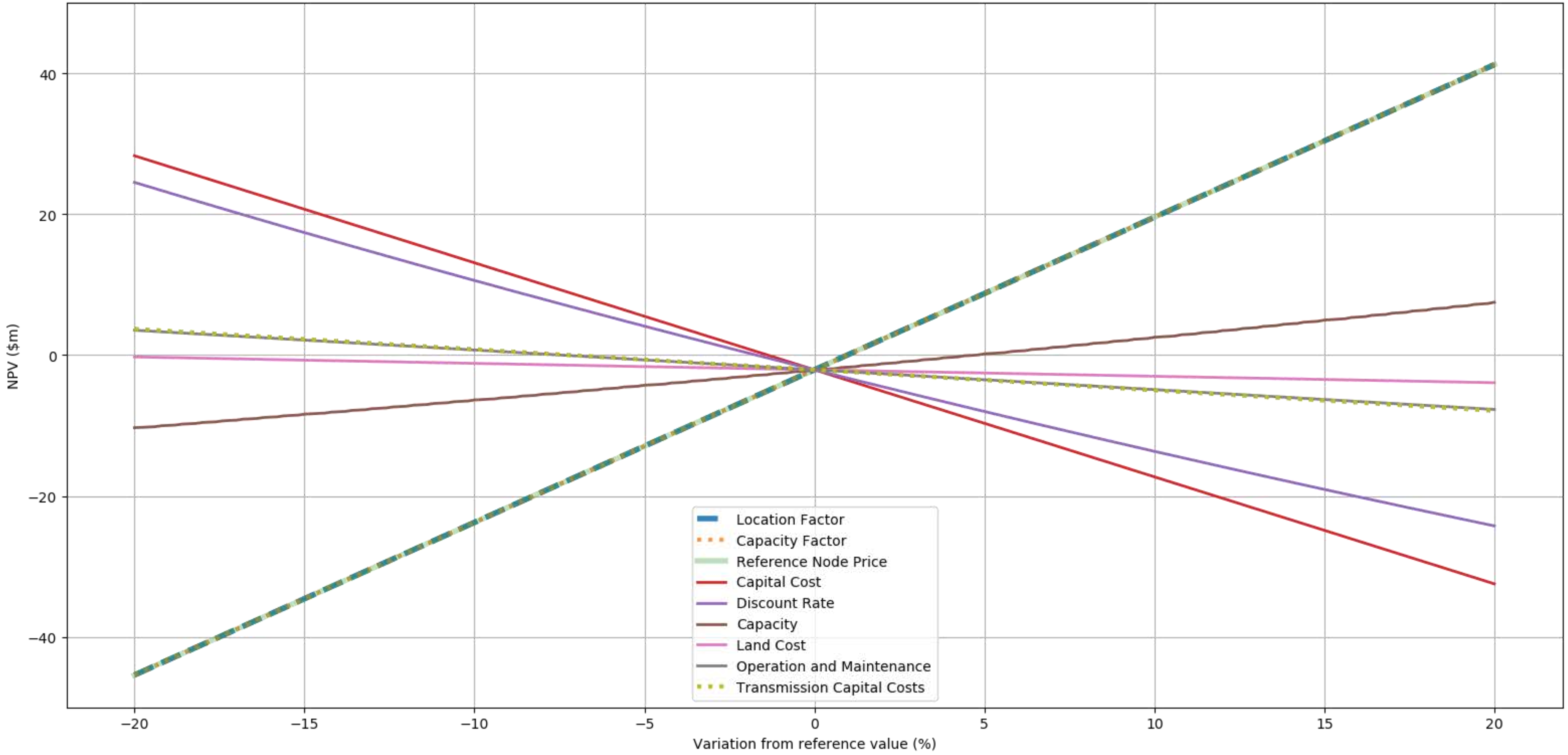


Figure 4: Sensitivity of NPV to inputs for a 160 MW utility-scale solar system.

2.4.3 Scenarios

Various scenarios were devised to run the model, with their parameters listed in Table 2. The scenario parameters of inflation rates, nominal discount rates, nominal internal rates of return and prices for Scenarios 3 to 5 have been set by MBIE. The parameters in each set of scenarios were set as outlined below.

Table 2: Price scenario parameters.

ID	Name	Benmore Average Price (CY2020), $/MWh	General Price Inflation	Electricity price inflation	Land value inflation	O&M price inflation	Wage inflation	Nominal discount rate	Nominal IRR criteria for selecting potential site
0	New Normal Base Case	100	2%	2%	5%	2%	3%	7%	8.5%
1	New Normal Scenario One	100	2%	1%	8%	2%	3%	8%	9.5%
2	New Normal Scenario Two	100	2%	3%	3.5%	2%	3%	5%	6.5%
3	EDGS Base Case	85	2%	2%	5%	2%	3%	7%	8.5%
4	EDGS Scenario One	85	2%	1%	8%	2%	3%	8%	9.5%
5	EDGS Scenario Two	85	2%	3%	3.5%	2%	3%	5%	6.5%
6	Reset Back Base Case	70	2%	2%	5%	2%	3%	7%	8.5%
7	Reset Back Scenario One	70	2%	1%	8%	2%	3%	8%	9.5%
8	Reset Back Scenario Two	70	2%	3%	3.5%	2%	3%	5%	6.5%

- Scenarios 3, 4 and 5 are the core scenarios and use the 2017 electricity price used in the 2019 EDGS (2017 prices are used as 2020 prices with inflation adjustment).

  In the Base Case scenario (ID 3), we assume that electricity prices increase at the same rate of inflation (2%) so that the real price of electricity remains constant at $85/MWh in 2020 dollars, which is consistent with the wholesale electricity price indicator in the EDGS 2019 scenarios in 2040s.[6] Over the period from 1978 to 2015, real dairy farmland prices increased on average 2.6% per annum (see (RBNZ, May 2016)) and hence land value inflation is assumed to be 5% per annum in the base case. The nominal discount rate is assumed to be 7% which is consistent with that used in the report on wind generation stack update (Roaring 40s Wind Power Ltd, March 2020). Also, as noted earlier, the required rate of return is increased by adding 1.5%.

  As this study is an exploratory in nature, it is important to explore the sensitivity of the results to some key economic assumptions. The assumptions chosen for the next two scenarios (ID 4 and ID 5) are quite extreme in order to provide a broad range of estimates of the potential solar sites.

  In the EDGS Scenario One (ID 4), the real price of electricity declines by one percent per annum, reflecting further technological improvements in energy markets. The real price of electricity is projected to reach a low of $63/MWh in 2050. We also assume that both land price inflation and nominal discount rate are 3 percentage points higher than the base case. This combination makes solar systems less economically viable in comparison with the base case.

[6] The price indicator in EDGS is set based on the average long-run marginal cost of the new build entering in the market.

In the Scenario Two (ID 5), high electricity price inflation (3%), low nominal discount rate (5%) and weak land value inflation provide a favourable opportunity of utility-scale solar investment.

- Scenarios 6, 7 and 8 are added to understand the forecast sensitivity to electricity price. These are referred to as ‘reset back’, as the average Benmore price in these is slightly lower than the 2014-2017 calendar year average price.

- Scenarios 0, 1 and 2 also investigate the sensitivity of the forecast to electricity price, using a price below the 2018 and 2019 calendar year average price of 107 $/MWh. These are referred to as ‘new normal’ to reflect the higher price of 2018 and 2019 persisting.

2.5 Revenue model

Section 2.4.1 introduced utility-scale solar revenue which depends on:

- energy price, which is location and time dependent; and
- solar resource and the energy generated from this using the solar system conversion of solar resource to AC electrical output.

Revenue would ordinarily be determined on a half-hourly basis from metered energy, and the price which may be a contract price and/or final nodal spot price. For the purpose of this model, it is assumed that most energy from a utility-scale solar system will be sold on contract and that the contract price will be based on local spot prices. Because of the nodal spot pricing used in New Zealand's wholesale electricity market, price will vary by location, hence considering price by location is important. However, for a model that considers potential generation sites across the whole of the country, it is useful to have price scenarios based at one location. Hence price scenarios, as given in Table 2, are based on prices at Benmore, the southern terminal of the HVDC link, and are adjusted by solar weighted location factors. The resulting revenue in the model is then determined according to

$$R_Y \cong Q_{LY}\ \overline{P_{R\,Y}}\ \overline{LF_{GXP\,Y}} w_{LY}^{h},$$

Equation 3

which represents the ***capacity*** (MW) x ***capacity factor*** x 8,760 multiplied by ***reference node price*** (\$/MWh) x ***location factor*** introduced in Section 2.4.1.

In Equation 3:

Q_{LY} is the solar system energy output (MWh) at its location L and over year Y (***capacity*** (MW) x ***capacity factor*** x 8,760), with adjustments for losses, module degradation, array over-sizing and tracking discussed earlier. If a solar system occupies several land cells the capacity factor is a weighted average based on capacity of the cells.

$\overline{P_{R\,Y}}$ is the reference node R (Benmore) price average for the year Y, as given in the scenario inputs (Table 2) and adjusted by each scenario's electricity price inflation.

$\overline{LF_{GXP\,Y}}$ is the average location factor for the year Y at the GXP to which the solar system connects (directly in the case of transmission connected solar or via a zone substation in the case of distribution connected solar).

w_{LY}^{h} is a solar weighting factor at the location at which the energy is sold. This ensures that the prevailing location factors at the time solar generates are used in the analysis (night-time prices are irrelevant to solar generation for example). Hourly solar system generation is used at each location to determine the weighting factor by location.

As well as this being a model rather than a real utility-scale solar system with actual metered quantities and prices, the revenue equation is approximate. The principal reasons for this are (1) the weighting factor is calculated at a location close to the potential solar system but not exactly at it, and (2) the weighting factor is calculated using historical data rather than actual data at the time the solar system generates.

A further reason why the revenue equation is approximate is that the average location factor at a location is calculated from historical data and may not be representative of future location factors; it also excludes price separation events that usually occur from constraints. In other words, it is based on the recent transmission grid configuration and generation location/dispatch, rather than possible future grid changes and new generation. To understand such interactions would involve an integrated forecasting approach that considers all forms of generation, together with solar and optimal grid expansion. Such an approach is out of the scope of this study, and the forecasts produced by this model must be considered in conjunction with possible medium- long-term electricity infrastructure changes. Infrastructure changes that will permanently increase or lower location factors are particularly important.

Location factors are determined such that the location factor reduces with increasing solar generation. This reflects the reduction in losses that occur as demand is effectively reduced at a GXP by the solar system generation.

Solar resource across New Zealand is modelled to km x km cell resolution to match the same land cells that the LCDB was converted into, as introduced previously. A proprietary model was used for this, which utilises 18 years of hourly meteorological data recorded between 2000 and 2018 from more than 150 NIWA stations, in conjunction with multispectral imagery from the Himawari series of satellites. In addition, high-resolution digital elevation data from the Shuttle Radar Topography Mission (SRTM) is used to model the impact of topographic shading, sky occlusion, and ground reflection on the incident irradiance at the surface of the earth. The output of the model is an array of 267,535 values, which represent the expected average annual energy output of an optimally oriented PV system installed within each cell of a 1 km x 1 km grid covering New Zealand. The model accounts for time-variant losses due to angle of incidence and spectral mismatch, as well as expected average losses due to factors such as self-shading, soiling, module mismatch, and inverter and wiring losses. Modules are modelled with an efficiency of 17%, noting that reported efficiencies are usually cell efficiencies, typically above 20%, measured in ideal conditions without the modules' protective covering and wiring. Figure 5 displays the model output, showing the high solar generation areas.

A further adjustment is made in this model to account for single-axis tracking, which increases solar system energy output.

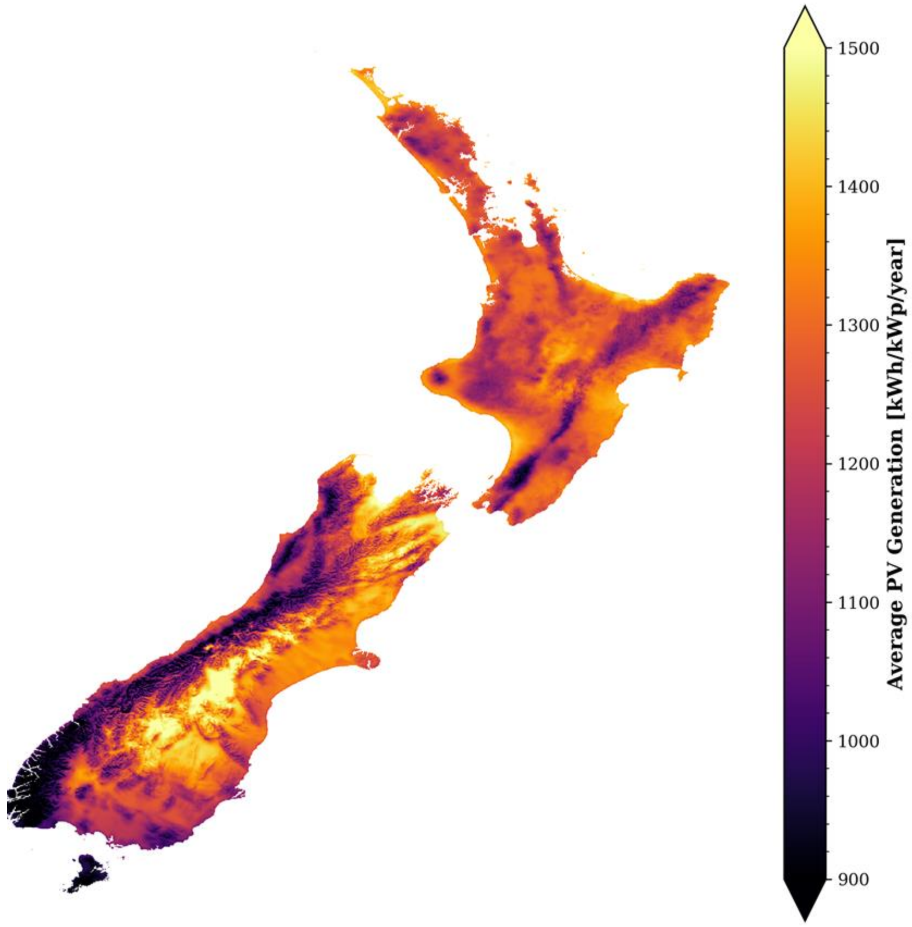


Figure 5: Annual solar generation from a 1kWp fixed axis optimally tilted and oriented PV system with 13.5% soiling, self-shading, module mismatch, DC-AC and wiring losses at each LCDB km x km cell considered in the model. Dividing the legend values by 8,760 hours per year gives the annual capacity factor. This is a measure of a solar system's ability to convert its capacity, and the substantial investment in it, into saleable energy. The capacity factors in this figure vary substantially from 0.118 to 0.197 (with module tracking and array over-sizing included).

2.6 Utility-scale solar system costs

A key input to modelling any generation is the *capital cost* or overnight capacity cost, with units of $/kW. In the case of PV, the units used are NZ$/Wp-ac, which gives the peak PV output capacity at the AC side of a solar system (where it connects to either the distribution or transmission network), in New Zealand currency. Peak PV output capacity is used because irradiance conditions vary continuously, and PV solar modules degrade in capacity over time. The degradation rate of PV solar modules in the model is at a rate of 0.8% per annum, although the model 'over sizes' array capacity by an 'over capacity factor' of 20% of AC capacity to account for module degradation over time. This is where a utility-scale PV system is built with more modules than the inverter capacity. There may be more optimal ways of offsetting module degradation, such as adding array capacity over time. However, results show that an initial oversizing does increase the overall rate of return of a utility-scale solar system. Further, as forecasts are considered in the future, the increase in rate of return improves as module costs decrease over time. This modelling does lead to the need to know module cost as well capital cost. As well as offsetting module degradation over time, oversizing an array also improves the *inverter loading ratio*. This is where the inverter is loaded closer to its capacity for a greater percentage of the day. As a result, more of the sun's energy is collected throughout a day.[7]

First-generation mono-crystalline and multi-crystalline PV solar technology has been used for the model, as opposed to second-generation thin film solar cell technology such as cadmium telluride (CdTe), or copper indium gallium selenide (CIGS), and newer third- or fourth-generation technologies such as organics and perovskites. The principal reasons for this are that crystalline silicon displays consistent reliable cell efficiency that is higher than most other technologies, and importantly makes up well over 90% of modules produced worldwide, with the remainder being thin film (Fraunhofer ISE, November 2019). This is crucial in assessing future capital cost.

Some newer technologies do display higher cell efficiencies, such as perovskite on silicon and multi-junction and / or concentrator cells. However, these are all new technologies not in large scale production. In addition, concentrator cells are more suited to direct irradiance environments, unlike Aotearoa New Zealand which has more diffuse irradiance from cloud cover. It is assumed that if such new technology, with higher efficiency and therefore capacity factor, became available in production quantities, it would come at a cost premium that would offset its higher efficiency. Thus, it would be at best comparable to the equivalent crystalline silicon, which has had many years of production and installation optimisation, with the ensuing steeply declining learning curves.

Capital cost is a particularly important consideration in assessing renewable generation, as it is usually well in excess of that of fossil fuel generation of the same capacity. However, marginal fuel cost is almost always close to zero, if not zero, unlike fossil fuel generation where the marginal cost is determined by fuel and maintenance cost. A number that should always accompany the capital cost of generation plant, especially renewable, is *capacity factor*. Capacity factor of a renewable generator is the measure of the resource available to it and the ability of its capacity (measured in MW) to convert that resource into saleable energy (measured in MWh). Capacity factor is closely related to the solar resource, solar module efficiency and inverter characteristics. Solar resource

[7] This assumes that the gains due to increasing the inverter loading ratio are greater than the losses due to 'clipping' of the output power. Typically, the maximum DC-AC ratio is limited to no more than 1.25 for this reason. A ratio of 1.2 is used in this study.

varies substantially by location in New Zealand due to weather patterns, naturally throughout a day, and by season and latitude with sun angle. Combined with the low efficiency of PV modules and electrical losses, the capacity factor of PV solar systems in New Zealand varies substantially, as shown in Figure 5.

Capacity factor can be improved by employing tracking, usually single-axis from east-to-west, but sometimes dual-axis which also tracks sun angle across seasons. While there is a capital cost premium on tracking systems, tracking can improve capacity factor and therefore a solar system's return. Indeed most utility-scale systems are being built with tracking as identified by the Lawrence Berkeley National Laboratory (LBNL) study (Bolinger, Seel, & Robson, 2019). Capacity factor improvement from tracking depends on the irradiance conditions, with greater improvement in higher irradiance environments. For example, an improvement of about 13.5% is identified in the LBNL study (Bolinger, Seel, & Wu, March 2016). Combined with increasing the inverter loading ratio, discussed previously, which on its own can improve capacity factor by around 5%, employing single-axis tracking is assumed to provide a 15% improvement in capacity factor in this study. This is believed to be a conservative increase in capacity factor, although suitable for a generalised model – other studies by the author, for specific locations, show improvements in capacity factor well in excess of 15%. However, it is not possible to generalise these to every location without undertaking extensive studies at each location.

Use of a single factor for capacity factor improvement is considered acceptable in this model which considers annual energy generated. In a half-hourly or hourly model, the modification of the generation profile over the day and/or year from a tracking system should be modelled. The half-hourly weighting of location factors by local PV system generation (See Section 2.5) is an exception, and leads to a more approximate location factor weighting.

2.6.1 Capital cost component modelling approach and literature review

To understand the capital costs of PV solar, a bottom-up modelling approach was adopted as utilised by NREL (Fu, Feldman, & Margolis, 2018). The reason for using such an approach was to allow different inflation rates and learning curve rates to be applied to different components in projecting the capital costs forward as a time series. A variety of organisations report on historical renewable energy costs. However, considerable care must be taken in using or comparing them, as a variety of measures are used ranging from capital costs ($/kW) to levelised cost of energy (LCOE) ($/MWh). Moreover, there are a variety of components that make up capital costs, and not all may be covered. The same applies to LCOE, with some organisations such as IRENA using different definitions to determine LCOE.

The main resource used in developing the bottom-up modelling approach was NREL's U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018 (Fu, Feldman, & Margolis, 2018), which gives a detailed breakdown of the components that make up a PV system's capital cost. As with other studies, the NREL study was based on historical costs of built systems. However, the most useful aspect of the NREL study was that it gave capital costs by system size ranging from 5 MW to 100 MW systems.

The LBNL study gives system costs by year from 2010 to 2018 based on actual projects (Bolinger, Seel, & Robson, 2019). This was reviewed and considered for this study because the time-series of costs may have been useful in projecting forward to develop a time series into the future. However, the capital costs in this study show considerable variation within each year, likely due to a variety of system sizes.

The most recent IRENA study of Renewable power generation costs in 2018 (IRENA, 2019) does not classify its results by utility-scale size (multi MW schemes), but it does give a breakdown of costs by component similar to those from the NREL study by Fu et al. (2018). It also reports capital costs ($/MW) and LCOE ($/MWh), although LCOE is of no use in developing this model. This is because LCOE depends on many factors including energy which varies by location, amongst other things; thus, LCOE is an output of this model, not an input. In its Future of Solar Photovoltaics report, IRENA predicts that

> *Globally, the total installation cost of solar PV projects would continue to decline in the next three decades. This would make solar PV highly competitive in many markets, with the average falling in the range of USD 340 to 834 per kilowatt (kW) by 2030 and USD 165 to 481/kW by 2050, compared to the average of USD 1,210/kW in 2018.* (IRENA, November 2019)

Combined with the observations from the LBNL study this gives a benchmark for checking results of a time series of PV capital costs developed for this model, as discussed in the Appendix.

Using Fu et al.'s (2018) NREL study data and the bottom up approach, each component of a PV system was considered at the different generator capacity levels of 5, 10, 50 and 100 MW. Each component was then extrapolated to 1 MW size and 200 MW size to give a table of capital costs by component in 2018, for both fixed angle and single-axis tracking systems. Single-axis tracking system costs are given in Table 3.

Table 3: PV solar capital cost components (NZ$/Wp-ac) in 2018. The components not shown have been removed as they are incorporated elsewhere in the model. Care should be taken when comparing these total figures with other capital costs reported for solar given that a number of components are not included. EPC: Engineering, procurement and construction; BOS: balance of system.

Component	Single-Axis Tracking					
	1 MW	5 MW	10 MW	50 MW	100 MW	200 MW
Developer net profit						
Contingency	0.06	0.04	0.04	0.04	0.04	0.04
Developer overhead	0.27	0.20	0.13	0.04	0.03	0.01
Transmission line						
Interconnection fee						
Permiting fee	0.07	0.04	0.03	0.01	0.01	0.01
Land acquisition						
Sales tax						
EPC overhead	0.16	0.14	0.13	0.11	0.09	0.04
Install labour and equipment	0.21	0.19	0.17	0.16	0.14	0.14
Electrical BOS	0.29	0.24	0.20	0.14	0.11	0.09
Structural BOS	0.31	0.24	0.23	0.21	0.19	0.19
Inverter only	0.07	0.07	0.07	0.07	0.07	0.07
Module	0.67	0.67	0.67	0.67	0.67	0.67
Total	2.12	1.84	1.67	1.47	1.36	1.27

As shown in Table 3 several components have been removed, as they are covered elsewhere in the model. Developer net profit is accommodated in the rate of return, discussed in Section 2.4; the transmission line and interconnection fee is accommodated in the transmission cost, discussed in Section 2.7; land acquisition is accounted for in the land cost, discussed in 2.8; and all costs are excluding sales tax.

Since the economic model assesses rate of return as far out as 2060 and over a 25-year period, a time series model of PV solar capital costs is required. Such a model should also give an indication of how components of the capital cost vary in relation to one another over time. For example, modules are expected to reduce in contribution to total capital costs, while labour components, such as Engineering, Procurement and Construction, and Installation increase as a proportion, especially with wage inflation. This model is discussed in detail in the Appendix.

As discussed in the Appendix, prices of modules and PV components over time can be related to worldwide PV module production via learning curves. For this reason, two scenarios of worldwide PV module production are used by this study to examine utility-scale solar forecasts:

- Production Scenario 0, where worldwide PV module production continues to grow at the rate from 2010 to 2018 until 2024, after which growth begins to slow; and
- Production Scenario 1, where worldwide PV module production begins to slow from 2019.

Worldwide production from each of these scenarios, compared with various forecasts, is shown in Figure 6.

Figure 7 and Figure 8 show the capital costs of PV systems projected forward, in nominal terms (capital costs in real terms are shown in the Appendix, Figure 25 and Figure 26). Figure 9 shows the contribution of components to the overall capital cost, showing how modules dominate the cost as systems become larger, but over time the labour costs take on a larger proportion of the overall cost.

The earlier quoted 2030 IRENA projections, converted to New Zealand currency by dividing by 0.75, are lower at the lower end than the costs shown in Figure 25 and Figure 26 and about equal at the upper end. The 2050 IRENA projections converted to New Zealand currency are about half the costs shown in Figure 25 and Figure 26 at the lower end, and about 2/3 at the upper end. This gives a degree of comfort that the capital cost projections developed for the solar forecasts in this report are similar to, or even higher than other projections (being higher makes this model more conservative).

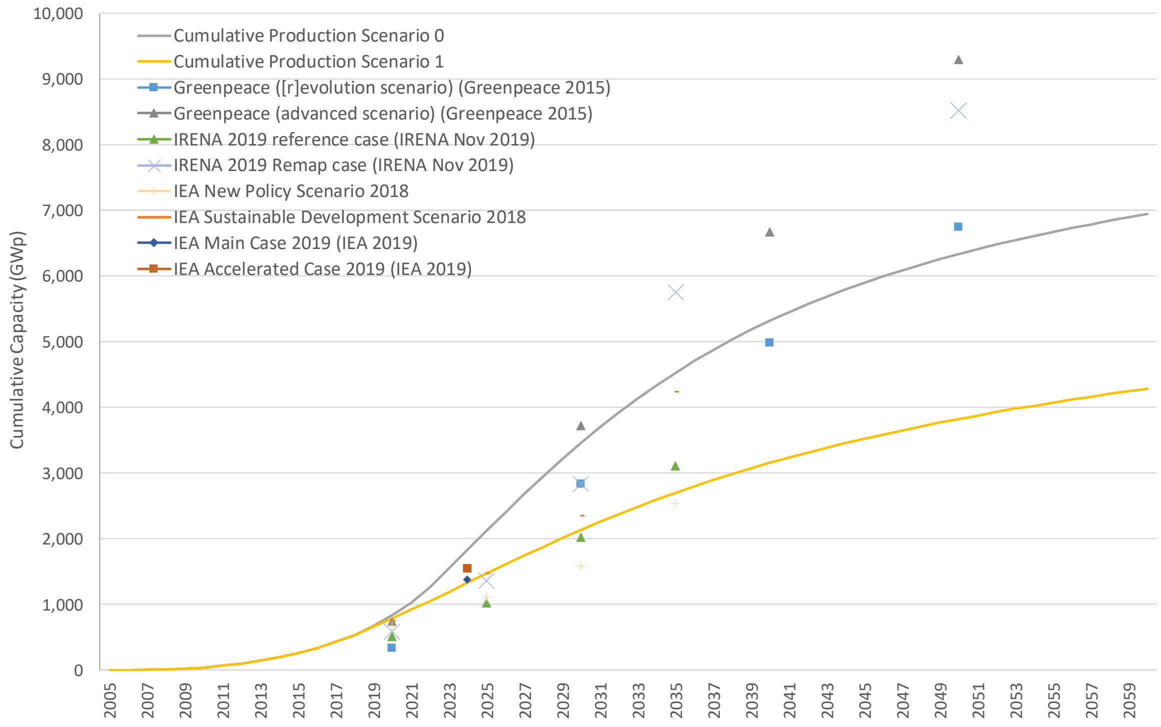


Figure 6: Cumulative worldwide PV module production.

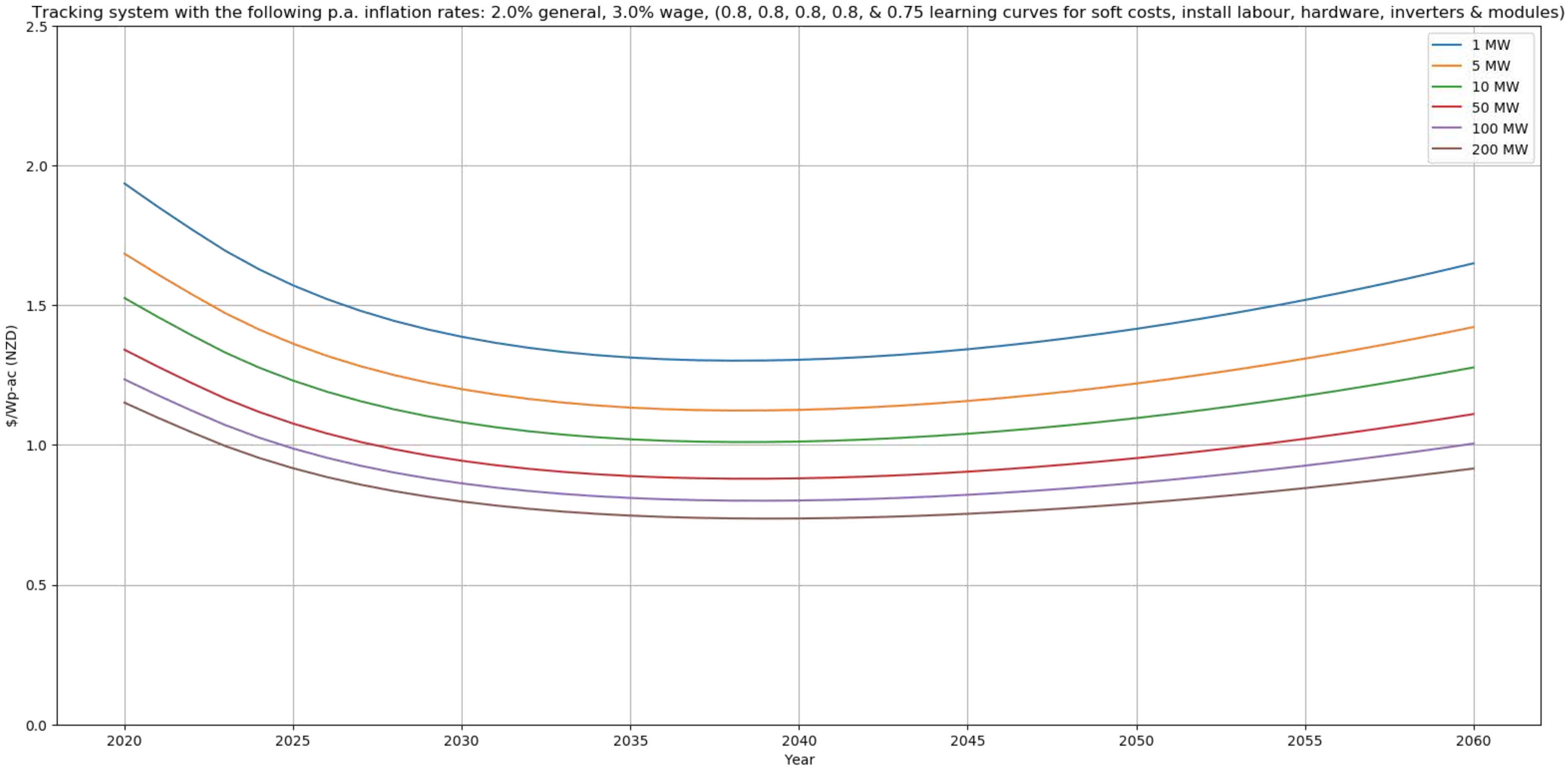


Figure 7: Tracking PV system capital costs (nominal), Production Scenario 0.

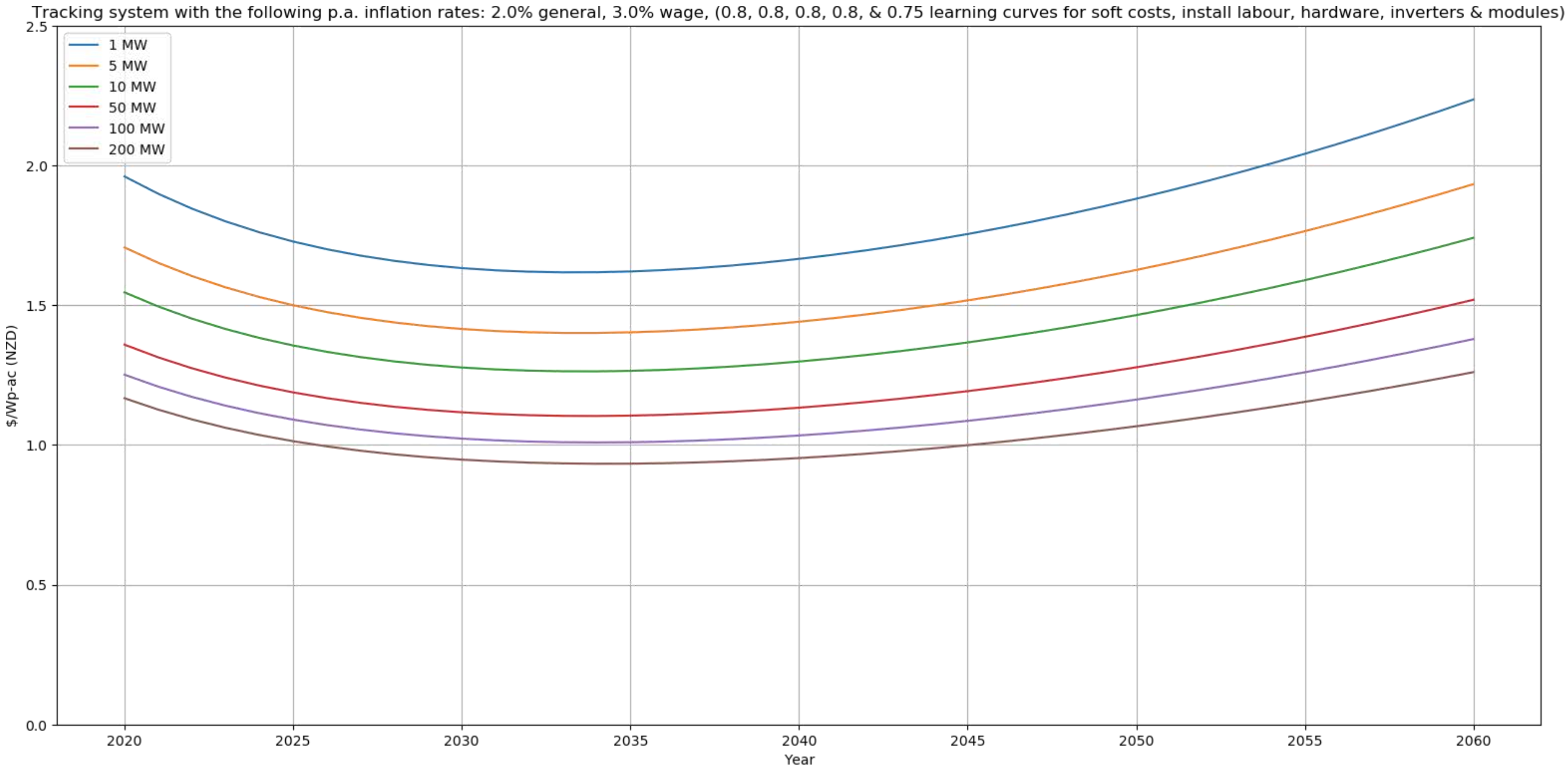


Figure 8: Tracking PV system capital costs (nominal), Production Scenario 1.

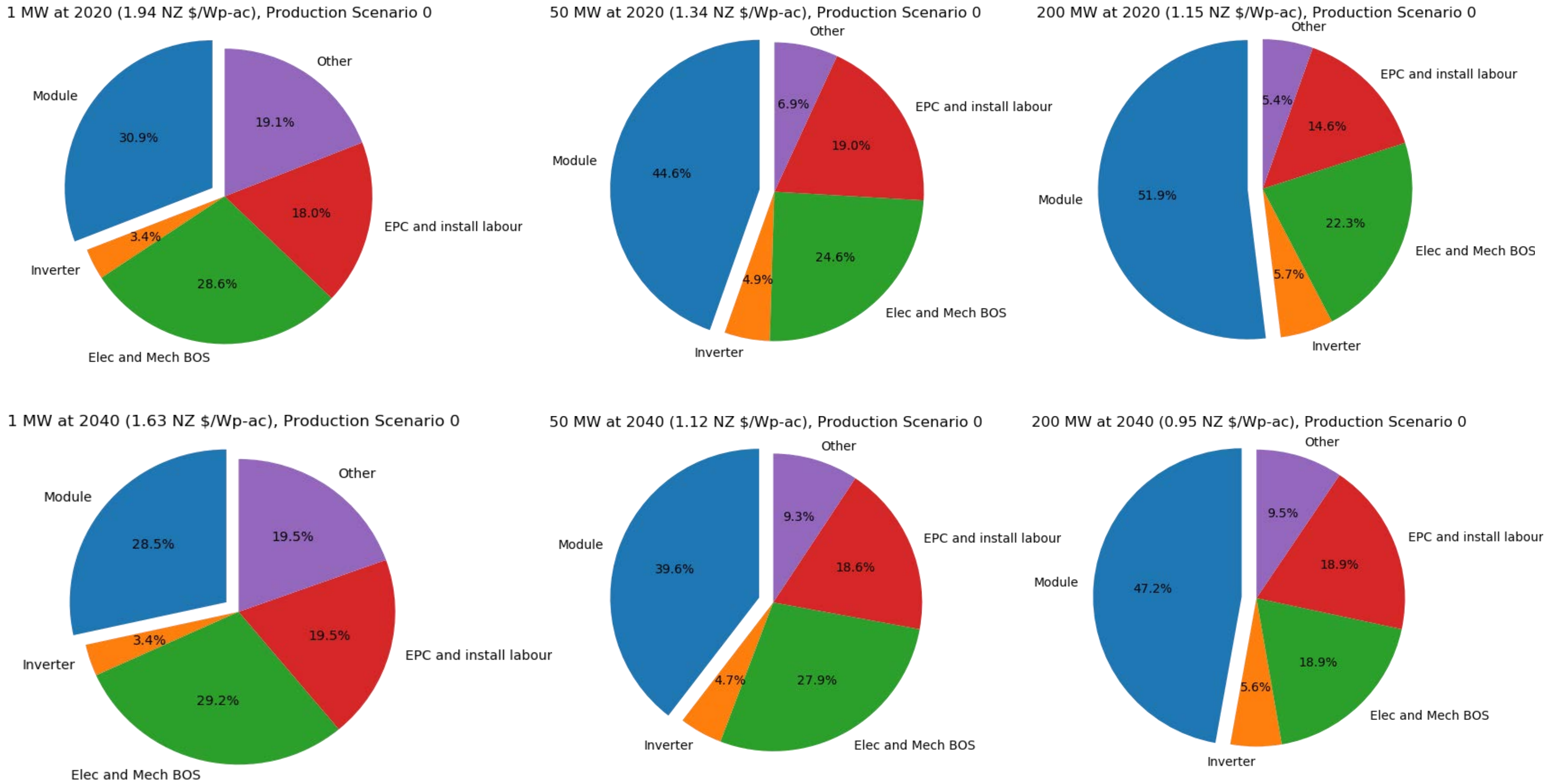


Figure 9: Make up of overall PV system costs at various sizes in 2020 and 2040 (nominal). Cost units are NZ $/Wp-ac and the production scenario is 0.

2.7 Transmission and distribution costs

A summary of the main assumptions and inputs to transmission and distribution costs is given below.

2.7.1 Transmission costs

Transmission interconnection charges, as published by Transpower in their transmission pricing data (Transpower (NZ) Ltd, 2020) are charged to loads (via distributors), not to generators. To form the shortlist of transmission connected solar systems, import capacities at each GXP (as provided by Transpower or estimated based on GXP export capacity) were considered. Further, at substations with more than one GXP (usually several voltages / several buses) the maximum import capacity at any voltage was used, on the assumption that the GXP connection would deal with any constraints between voltages and connect at the most appropriate voltage to maximise capacity. As with the location factor model, only one GXP at a substation is used in this model. While specific constraints may be present at each substation, this model more generally considers a substation as a single GXP with the highest connection capacity and lowest location factor.

Transmission costs are:

1. One-off investment transmission costs which include:

    a. A GXP/GIP (grid injection point) connection cost ($)

    The cost of connecting a transmission line from a new solar system to its closest GXP/GIP. This includes substation assets such as the structure, switchgear, control and protection, busbar work, land and design and project management. Its level depends on the connection voltage – in this model the following costs have been used:

    - 66kV: $5m (2020)
    - 110kV: $10m (2020)
    - 220kV: $15m (2020)

    Transmission and GXP/GIP voltage depends on the utility-scale solar capacity, introducing yet another trade-off between capacity and cost. Up to 60 MW utility-scale solar uses 66 kV transmission and connection voltage, from 60 MW to 120 MW uses 110 kV, and above 120 MW uses 220 kV. The reason is to not exceed transmission line conductor loading limits of typical conductor types used at transmission voltages.

    b. A transformer cost ($)

    A transformer is located at the utility-scale solar system to transform the solar system output to a voltage suitable for transporting its energy with minimal loss, and to interface to the transmission line and GXP/GIP voltage. A cost of $10m is used in all cases.

c. A transmission line build cost ($/km)

The cost of building a new transmission line to connect to the nearest GXP at the GXP voltage considered and is set at 0.5 $m/km or 1.5 $m/km for GXPs in densely populated areas to reflect the additional project cost. Excluded are land acquisition, consenting, and underground cable costs as they are extremely difficult to estimate except for a specific project.

It is assumed that the GXP connection and transmission line assets are built and owned by Transpower, with a one-off capital contribution by the utility-scale solar installer towards them, via an investment contract with Transpower. Transpower's investment contract deals with aspects of tax and depreciation. Essentially the tax depreciation benefit of the capital investment in transmission is passed back to the generator. Hence the model depreciates these assets at a rate of 8%, as given in Inland Revenue's tables for pylons and switchgear. The model does not account for administration fees or finance carrying cost. Given the assumed connection, line and transformer costs, these are likely in the error of these assumptions.

The transformer, which is assumed to be owned by the generator, gains a similar depreciation benefit, which is also accounted for, leading to a reduction in tax. The connection of the utility-scale solar system is assumed to be an 'N' level rather than 'N-1'. This means that there is no redundancy in the transmission of energy from the generator to the substation. Hence, should the transformer fail, the generator will be unable to sell its energy until the transformer is replaced. Likewise, if the transmission line is out of service for some reason such as maintenance or a fault.

With the line and substation assets owned by Transpower they attract an annual maintenance charge, which is paid to Transpower as discussed below.

2. Ongoing transmission maintenance charges

Since the transmission line and interconnection assets are assumed to be owned by Transpower, they will require maintenance payments to Transpower. The rates are based on Transpower's published maintenance recovery rates (Transpower (NZ) Ltd, 2020). These comprise:

a. The line maintenance recovery rate ($/km per annum)

Equal to 5,330 $/km per annum (2020) which is the published recovery rate for 220 kV tower lines.

b. The substation maintenance recovery rate (% of the cost per annum)

Equal to 1.74 % of the investment cost (given above) per annum as published by Transpower.

c. The South Island mean injection charge that currently applies to South Island generators for HVDC link cost recovery ($/MWh per annum)

   This charge is not applied (it is set to zero), as it is proposed in the current transmission pricing review by the Electricity Authority to remove that charge. A new charge to generators reflecting 'area of benefit' may be introduced, however no charge is modelled as neither the nature nor size have been established to date.

There may be other charges levied by Transpower such as switchgear operating costs, but these are excluded.

2.7.2 Distribution costs

Only incremental costs of connection are charged for in line with Part 6 of the Electricity Industry Participation Code 2010. Distribution costs are:

1. One-off investment distribution costs which is:

   a. A connection cost ($)

      This represents a fixed amount for application fee and testing ($6,200 as specified in Part 6 of the Electricity Industry Participation Code 2010) and engineering studies (estimated to be $100,000) required for up to 2 MW distribution connected solar, and increases from this amount ($106,200) to $320,000 for 5 MW distribution connected distributed generation. This represents more extensive engineering studies, and incremental costs of upgrading the distribution network such as protection, regulators and/or sections of conductor, as capacity increases.

      Above 5 MW capacity, where a sub-transmission line connection to a zone substation is required, the connection cost is assumed to be $2m.

   b. A transformer cost ($)

      The cost of a transformer depends the size of the solar system connecting. It is assumed to be $300,000 below 5 MW and $500,000 above 5 MW.

   c. A spur line build cost ($/km)

      Since potential distribution connected solar sites are selected to be within no more than 2 km of a proxy medium voltage distribution line, the spur line cost of connecting to the medium voltage network for solar systems under 5 MW will not be large. The exact spur line unit cost used is not disclosed due to confidentiality. A minimum spur line distance of 1 km is always used to represent the fixed costs associated with establishing and connecting a spur line.

      Where a solar system is over 5 MW a dedicated 33 kV sub-transmission line is built to the zone substation. This assumes it will incorporate the existing MV lines as 11 kV under-build and use the same road corridor. The unit cost used was provided in confidence.

The distribution line build unit costs used include traffic management, design, contractor margin and project management.

2. Ongoing distribution maintenance charges

   It is assumed that there are no annual charges for distribution network connected solar systems.

2.8 Suitable land and its cost

Section 2.3 discussed the search for suitable land for utility-scale solar systems, including land class. It also discussed that a weighted average cost of land is determined after suitable land cells (for transmission connected) or land cell (for distribution connected) are identified for a solar system. The weighting considers area of each land class and the cost of the land class. The same costs for the land classes are used throughout New Zealand and are listed below.

- High Producing Exotic Grassland 40,000 $/ha
- Low Producing Grassland; and 30,000 $/ha
- Depleted Grassland 10,000 $/ha

In reality there will be variation across New Zealand. Such variation could be included in the future but given the relatively low sensitivity of NPV to land cost these are suitable initially. Further, the scenarios incorporate land cost inflation rates that could reflect ongoing demand for land for other purposes such as agriculture and crops.

To discourage siting of utility-scale solar close to populated areas, land cost was adjusted to reflect urban land prices. A database of 576 populated areas, obtained from Statistics NZ, was used to determine distance of each land cell identified as a potential solar system from urban areas. A 'land cost adjustment' based on proximity to populated areas was then made by multiplying the weighted average land cost. Within the boundary of each town the land cost was set at 4,000,000 $/ha (the *urbanLandCost*) plus the weighted average cost. Outside the town boundary the land cost was set to the weighted average cost plus *urbanLandCost* x $2^{-\sigma(d-r)/r}$ where σ is the *landCostDecayFactor*, d the distance from the town centre (m) and r the town's radius (m). With the parameters used, additional land cost is at a factor of 6.25% of the *urbanLandCost* at an additional distance of the urban centre's radius beyond the boundary and 0.39% of the *urbanLandCost* at an additional distance of twice the urban centre's radius beyond the boundary. This piecewise function ensures very high land cost within the urban area and rapidly decaying land cost outside the urban boundary, dependent on the town's size. For example, Auckland's land prices outside the urban boundary will be higher for a longer distance than a small town such as Blenheim, as shown in Figure 10.

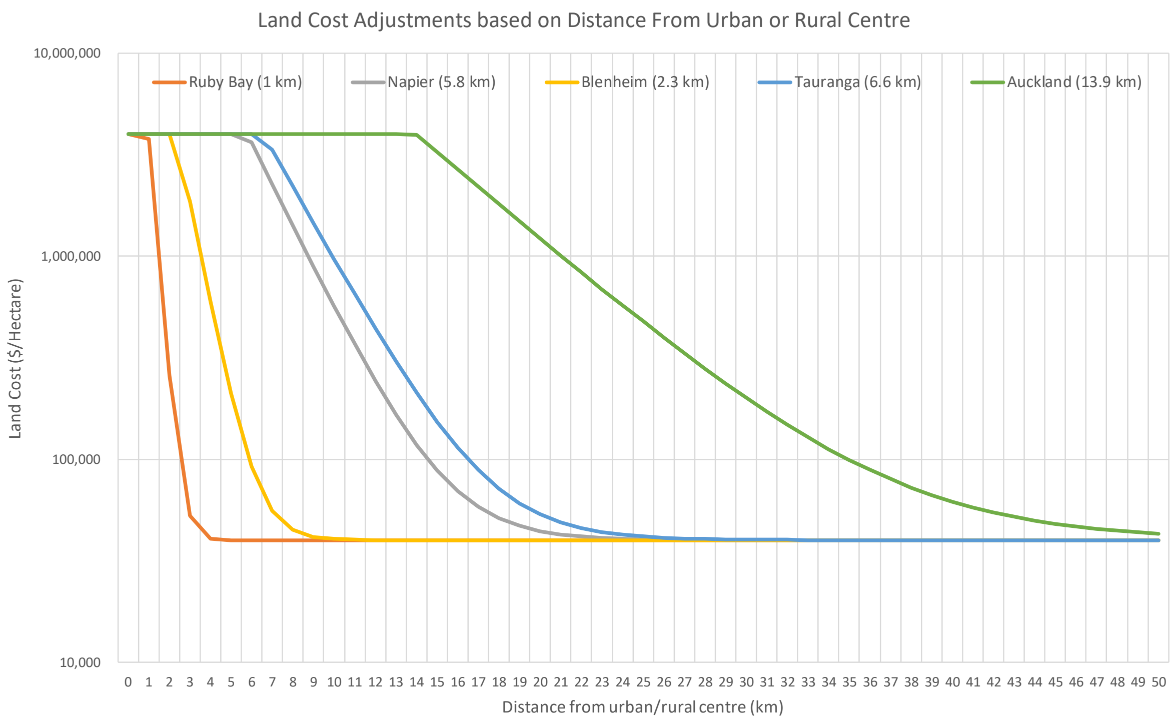


Figure 10: Examples of land cost adjustments close to populated centres where land cost is higher for high producing exotic grassland.

2.9 Operation and maintenance cost

Total annual operation and maintenance cost is based on a cost of 20 $/kWp-ac per annum. Studies such as the National Renewable Energy Laboratory study (Fu, Feldman, & Margolis, 2018) and the Lawrence Berkeley National Laboratory study (Bolinger, Seel, & Robson, 2019) confirm this value.

2.10 Wholesale market and trading costs

Wholesale market and prudential requirement costs are assumed to be met by the retailer. Credit risk / credit guarantee costs as part of a power purchase contract or hedge cover may exist but are not accounted for.

As with transmission interconnection charges, the cost of certain ancillary services, such as the *frequency-keeping* ancillary service is charged to loads. The *black start* and *over-arming* ancillary services are charged to Transpower and recovered through transmission charges (and therefore from loads). The *instantaneous reserves* ancillary service is charged to generators based on unit sizes. It is assumed that the unit size of each utility-scale solar component is small enough to not attract instantaneous reserve charges. That is despite them being up to 200 MW in total and connected via a single spur transmission line which presents an outage risk. No voltage control ancillary service is accounted for, although in the future solar systems may gain some further revenue for voltage-control through their inverters effectively acting as reactive power compensators.

3. Forecast Results and Discussion

The combined utility-scale solar capacity forecast for the three EDGS scenarios is shown in Figure 11, with the energy forecast shown in Figure 12. The solid bars are derived from the higher worldwide solar module production forecast (Production Scenario 0) which is still below the IRENA forecasts, but above the IEA forecasts. The patterned bars are derived from the lower worldwide solar production (Scenario 1) which is well below most forecasts, or just matches the most recent IEA forecast to 2024. The forecasts are tabulated in Table 4 for all price and production scenarios.

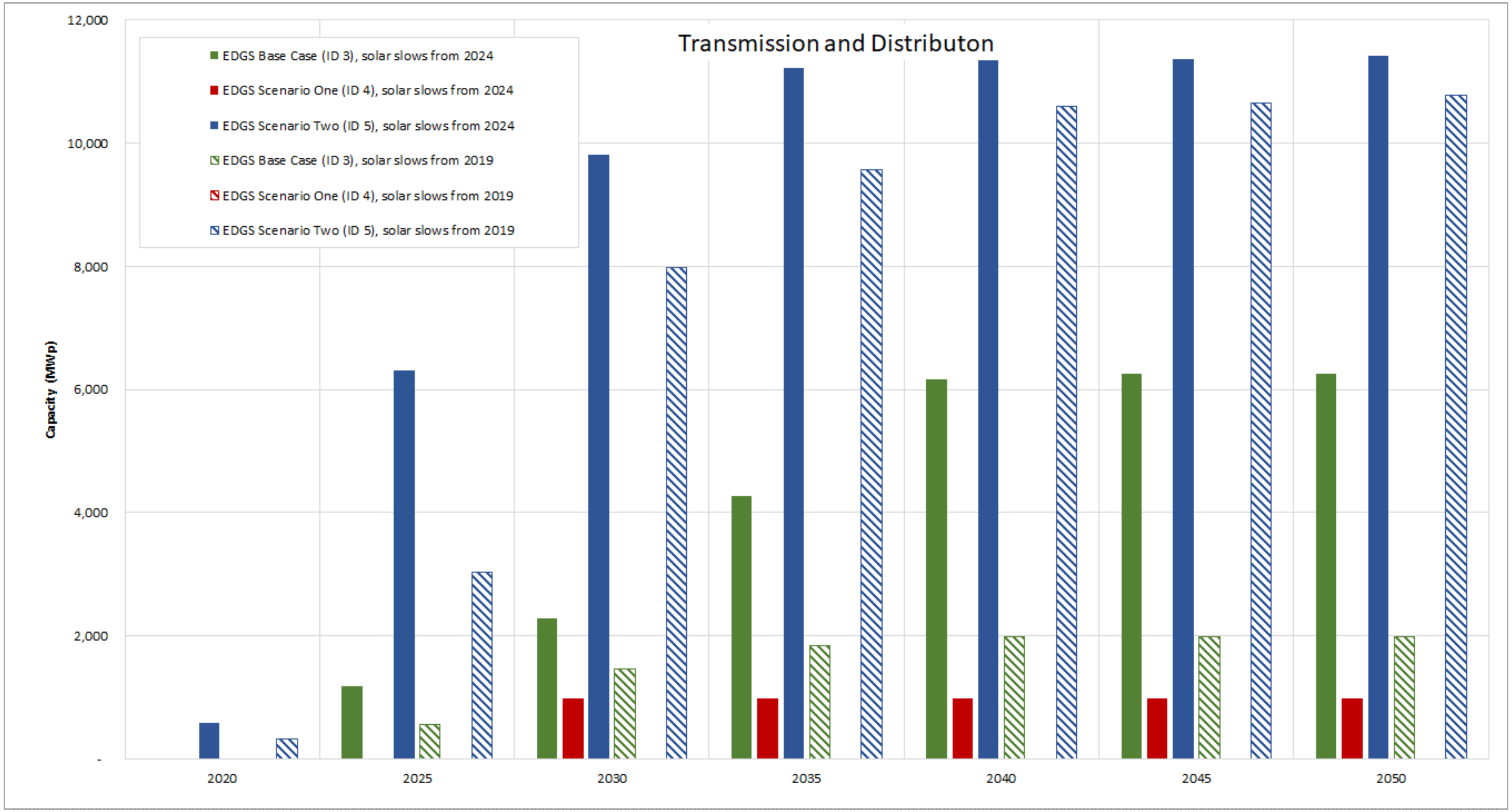


Figure 11: Transmission and distribution connected cumulative utility-scale solar capacity forecast.

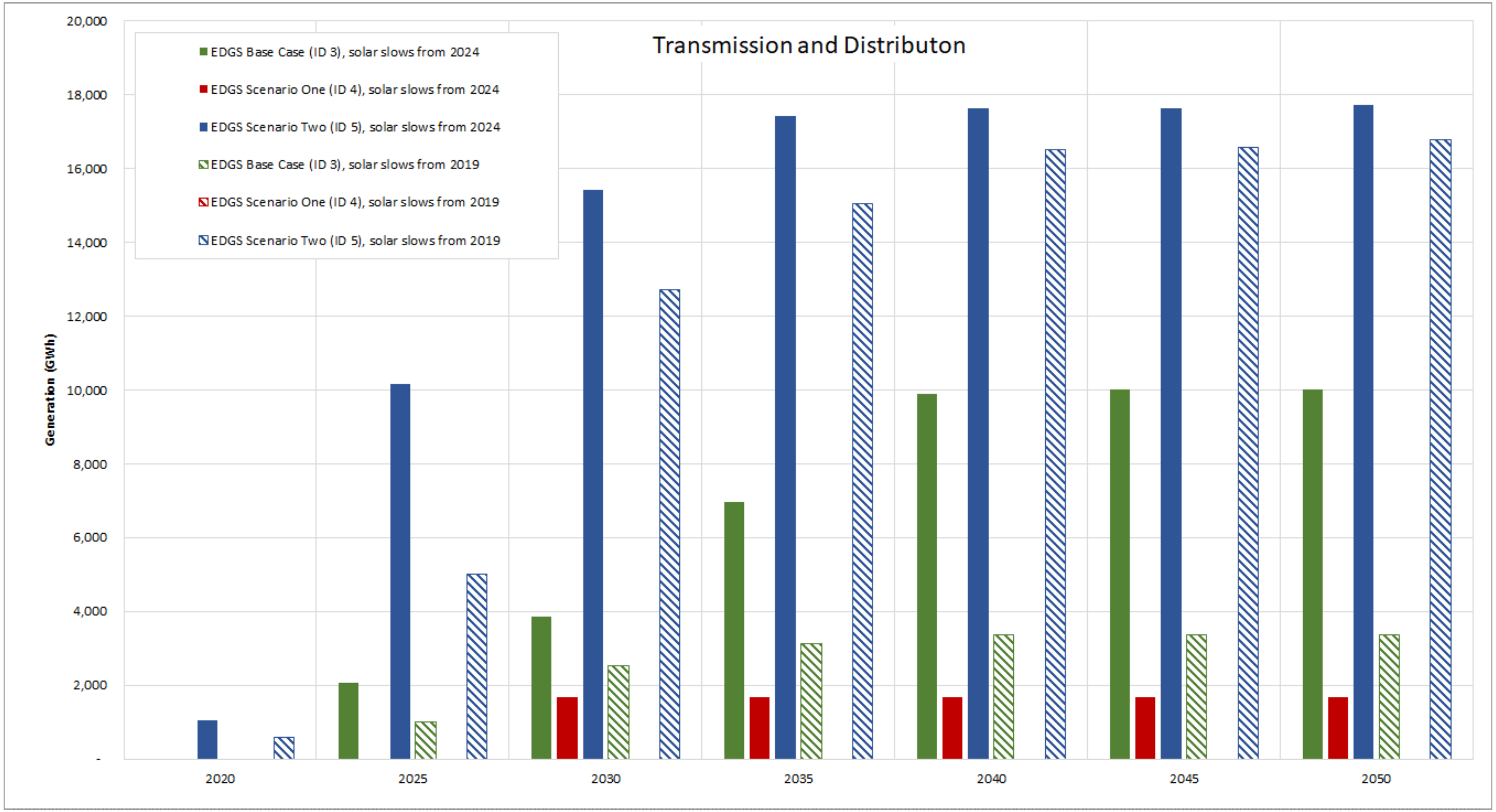


Figure 12: Transmission and distribution connected utility-scale solar annual generation forecast.

Table 4: Transmission and distribution connected utility-scale solar capacity forecast (MWp).

(a) Production Scenario 0, where worldwide solar production slows from 2024

ID	Name	2020-2024	2025-2029	2030-2034	2035-2039	2040-2044	2045-2049	2050-2054	2055-2059	2060-2064	Total
0	New Normal Base Case	582	2,961	4,353	532	220	-	-	-	-	8,648
1	New Normal Scenario One	-	1,489	379	-	-	-	-	-	-	1,868
2	New Normal Scenario Two	2,442	8,369	1,059	-	60	315	80	79	-	12,404
3	EDGS Base Case	-	1,189	1,092	1,996	1,895	80	-	-	-	6,253
4	EDGS Scenario One	-	-	977	-	-	-	-	-	-	977
5	EDGS Scenario Two	583	5,731	3,507	1,398	140	-	60	-	158	11,577
6	Reset Back Base Case	-	-	973	-	496	-	-	-	-	1,469
7	Reset Back Scenario One	-	-	-	-	-	-	-	-	-	-
8	Reset Back Scenario Two	-	1,488	3,953	2,964	1,239	1,297	80	-	-	11,022

(b) Production Scenario 1, where worldwide solar production slows from 2019.

ID	Name	2020-2024	2025-2029	2030-2034	2035-2039	2040-2044	2045-2049	2050-2054	2055-2059	2060-2064	Total
0	New Normal Base Case	300	1,813	2,916	1,299	204	-	-	-	-	6,532
1	New Normal Scenario One	-	985	-	-	-	-	-	-	-	985
2	New Normal Scenario Two	2,224	6,699	2,045	180	-	60	100	-	157	11,465
3	EDGS Base Case	-	565	896	378	140	5	-	-	-	1,984
4	EDGS Scenario One	-	-	-	-	-	-	-	-	-	-
5	EDGS Scenario Two	327	2,701	4,955	1,585	1,038	40	140	-	60	10,846
6	Reset Back Base Case	-	-	-	-	777	198	-	-	-	975
7	Reset Back Scenario One	-	-	-	-	-	-	-	-	-	-
8	Reset Back Scenario Two	-	783	1,429	3,937	1,608	892	620	639	479	10,388

3.1 Transmission connected utility-scale solar forecast

The transmission connected utility-scale solar capacity forecast for the three EDGS scenarios is shown in Figure 13, with the energy forecast shown in Figure 14. As before, the solid bars are derived from the higher worldwide solar production (Production Scenario 0) while the patterned bars are derived from the lower worldwide solar production (Production Scenario 1). The forecasts are tabulated in Table 5 for all price and production scenarios. The actual forecasts themselves were determined according to:

$$forecast\ capacity\ in\ year = \sum_{year} total\ shortlist\ capacity \left(1 - \frac{\sum_{year} total\ shortlist\ capacity}{\sum_{year} total\ longlist\ capacity}\right).$$

The purpose of this was to scale back the forecast depending on the comparative capacity of the shortlist and longlist (essentially a level of confidence in the shortlist). A scenario and year with a longlist capacity much higher than the shortlist capacity would receive a forecast close to the shortlist capacity. However, a scenario and year with a longlist capacity equal to the shortlist capacity would receive a forecast of zero.

Obviously this constrains the forecast to the existing transmission grid capacity (or distribution network capacity in the next section). Having identified the longlist in this model, future forecasts might also assess the viability of potential projects on the longlist based on factors other than land type, local irradiance, transmission or distribution network capacity and economics. For example, proximity to roading infrastructure (which is included by default in the distribution forecasts) and likelihood of land actually being available for solar development.

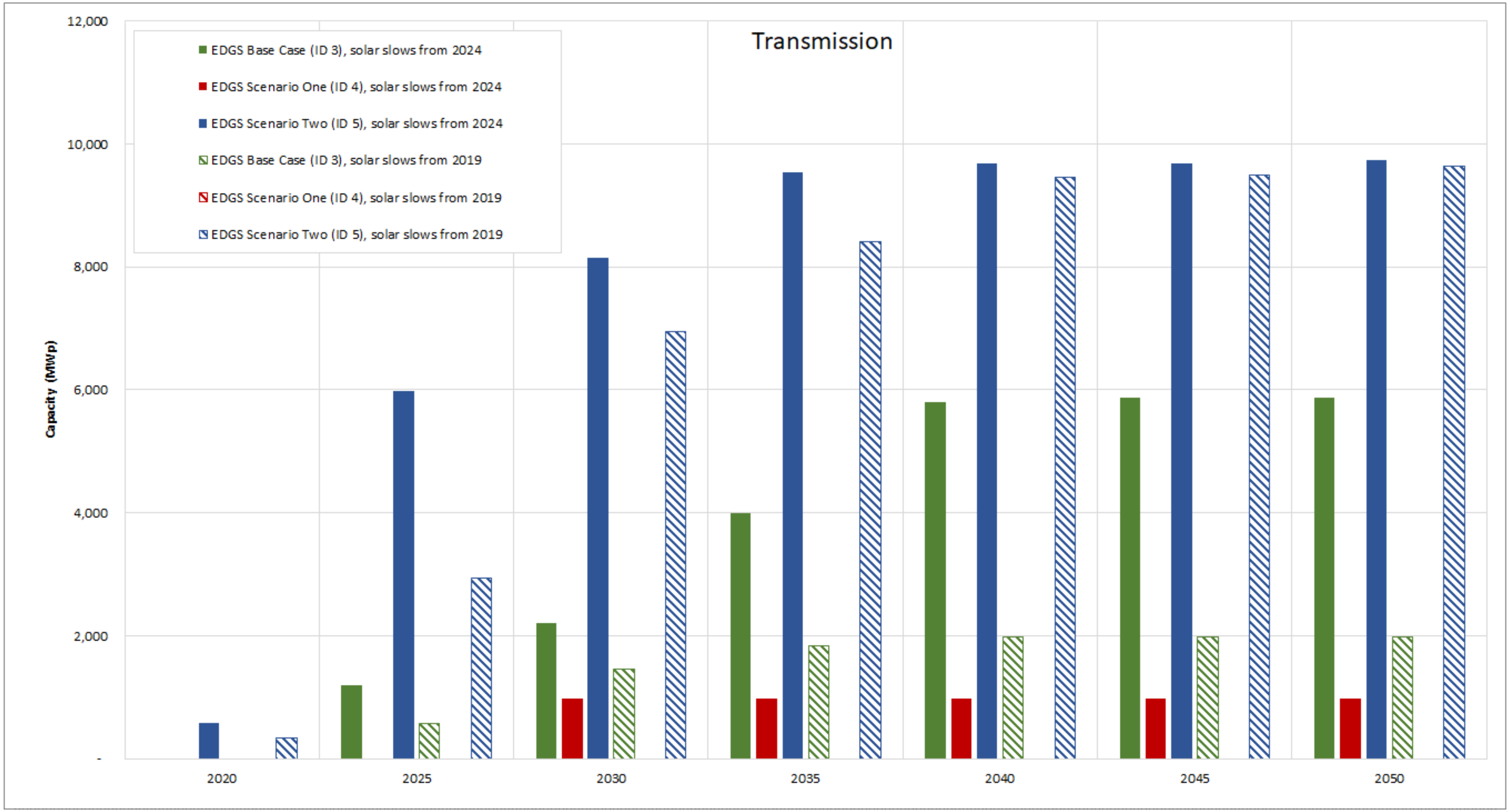


Figure 13: Transmission connected cumulative utility-scale solar capacity forecast.

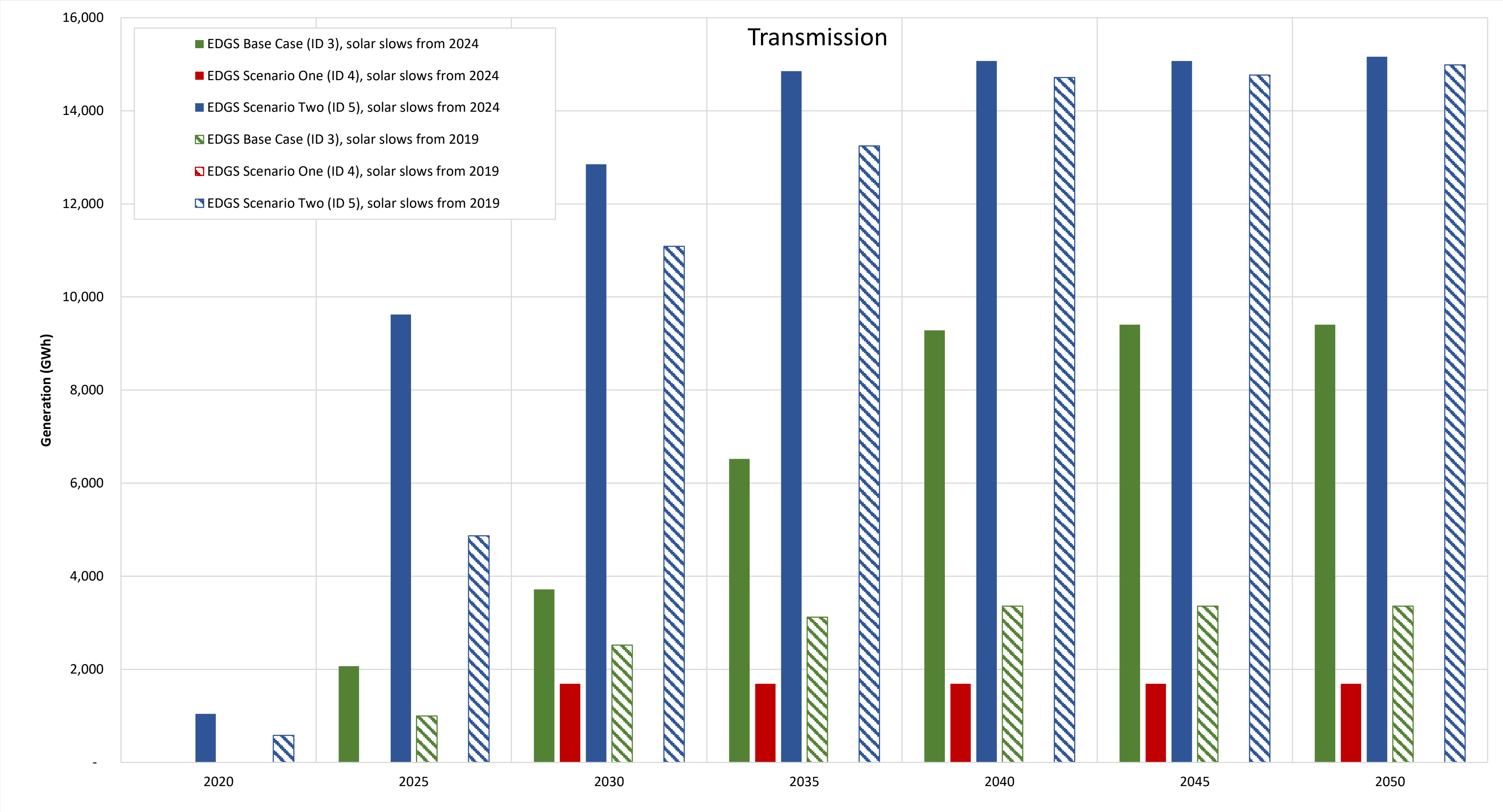


Figure 14: Transmission connected utility-scale solar annual generation forecast.

Table 5: Transmission connected utility-scale solar capacity forecast (MWp).

(a) Production Scenario 0, where worldwide solar production slows from 2024.

ID	Name	2020-2024	2025-2029	2030-2034	2035-2039	2040-2044	2045-2049	2050-2054	2055-2059	2060-2064	Total
0	New Normal Base Case	582	2,851	3,553	500	220	-	-	-	-	7,706
1	New Normal Scenario One	-	1,489	379	-	-	-	-	-	-	1,868
2	New Normal Scenario Two	2,410	6,152	1,059	-	60	315	80	79	-	10,155
3	EDGS Base Case	-	1,189	1,018	1,795	1,791	80	-	-	-	5,872
4	EDGS Scenario One	-	-	977	-	-	-	-	-	-	977
5	EDGS Scenario Two	583	5,403	2,159	1,398	140	-	60	-	158	9,900
6	Reset Back Base Case	-	-	973	-	496	-	-	-	-	1,469
7	Reset Back Scenario One	-	-	-	-	-	-	-	-	-	-
8	Reset Back Scenario Two	-	1,488	3,589	2,058	1,239	1,297	80	-	-	9,752

(b) Production Scenario 1, where worldwide solar production slows from 2019.

ID	Name	2020-2024	2025-2029	2030-2034	2035-2039	2040-2044	2045-2049	2050-2054	2055-2059	2060-2064	Total
0	New Normal Base Case	300	1,813	2,751	1,158	200	-	-	-	-	6,222
1	New Normal Scenario One	-	985	-	-	-	-	-	-	-	985
2	New Normal Scenario Two	2,211	5,312	1,978	180	-	60	100	-	157	9,997
3	EDGS Base Case	-	565	896	378	140	-	-	-	-	1,980
4	EDGS Scenario One	-	-	-	-	-	-	-	-	-	-
5	EDGS Scenario Two	327	2,612	4,013	1,459	1,038	40	140	-	60	9,690
6	Reset Back Base Case	-	-	-	-	777	198	-	-	-	975
7	Reset Back Scenario One	-	-	-	-	-	-	-	-	-	-
8	Reset Back Scenario Two	-	783	1,415	3,668	1,139	839	620	639	479	9,582

The ‘new normal’ Scenarios 0 and 2, where the forecast shows a strong utility-scale solar forecast in 2020-2024, demonstrate the sensitivity of solar uptake to electricity price, as already discussed. These scenarios also demonstrate some of the many factors that contribute to identifying suitable utility-scale solar locations. To examine this further, details of the 13 utility-scale solar systems that are forecast (on the shortlist) for 2020-2024 in Scenario ID 2 are given in Table 6. Interestingly the systems with the highest NPV are in an area with a lower nodal electricity price – they all have a location factor of 1.0, although the solar weighting increases that to 1.091. The capacity factor shows an excellent solar resource (for New Zealand) in South Canterbury (the Mackenzie District and Waitaki Valley).

However, the revenue from the system in the Tasman region is even higher, as a result of the higher location factor, which is also weighted to a higher price time of day and year. This results in even higher revenue for the Tasman case. Countering this is the increased land cost at the location of the potential solar system in Tasman, which is predominantly high producing exotic grassland compared to depleted grassland at the potential solar system locations in the Mackenzie District/Waitaki Valley. There is also some increase in the Tasman location’s land price due to its proximity to a populated centre. Also countering the higher revenue is the higher transmission investment cost for the system in the Tasman region – even though it is closer to the GXP, the GXP is in a populated area (Stoke) leading to a high transmission line build cost.

Table 6: Shortlisted utility-scale solar systems forecast for 2020-2024 in Scenario ID 2 (Production Scenario 0) (all figures are 2020).

Region	Distance to GXP/GIP (km)	Capacity (MW)	Capacity Factor	LCOE ($/MWh)	Average Solar Weighted Location Factor	Total Discounted Revenue ($m)	Investment ($m)			Annual Costs Discounted ($m)				NPV ($m)
							Solar Farm	Land	Trans-mission	O&M	Transmission Maintenance	Tax	Depreciation Tax Offset	
South Canterbury	9.2	200	0.201	88.2	1.091	468.2	254.2	6.6	29.6	59.9	4.6	113.0	-54.9	55.2
South Canterbury	28.6	200	0.207	88.5	1.091	480.3	254.2	6.2	39.3	59.9	6.2	116.0	-56.4	54.9
South Canterbury	28.9	200	0.208	88.6	1.091	481.0	254.2	7.0	39.5	59.9	6.2	116.2	-56.4	54.4
Tasman	13.4	200	0.196	100.2	1.211	504.2	254.2	26.5	45.1	59.9	5.0	123.0	-57.3	47.8
South Canterbury	9.7	200	0.197	89.7	1.091	456.6	254.2	6.6	29.8	59.9	4.7	109.8	-55.0	46.6
South Canterbury	5.2	200	0.193	90.4	1.091	450.2	254.2	7.8	27.6	59.9	4.3	108.1	-54.6	42.9
Bay of Plenty	19.0	200	0.191	98.2	1.170	475.1	254.2	23.0	34.5	59.9	5.4	114.8	-55.7	39.0
Central Otago	5.8	200	0.191	92.2	1.062	433.7	254.2	17.2	27.9	59.9	4.4	103.5	-54.7	21.3
Marlborough	4.2	100	0.190	102.9	1.213	245.9	135.4	8.7	22.1	29.9	2.9	59.7	-30.2	17.4
Marlborough	10.3	140	0.192	104.5	1.207	346.9	184.9	16.2	40.5	41.9	4.7	84.1	-42.8	17.4
Hawke's Bay	19.7	180	0.177	105.5	1.205	407.3	231.8	18.7	34.8	53.9	5.5	97.4	-51.3	16.5
West Waikato	24.8	200	0.178	103.3	1.156	437.1	254.2	22.9	37.4	59.9	5.9	104.0	-56.1	8.9
Canterbury	11.2	200	0.178	102.8	1.130	429.6	254.2	23.1	41.7	59.9	4.8	102.2	-56.8	0.5

Examining the EDGS Scenarios, the EDGS Scenario Two (ID 5) also shows utility-scale solar forecast for 2020 to 2024. This scenario has the lowest rate of return requirement (6.5%) but the highest electricity price inflation (3%). Given the cost of capital is predicted to decrease in the near- to medium-term, this rate of return may be realistic. However, the electricity price inflation of 3% is perhaps not so realistic, although that does not feature in 2020. The Scenario ID 5 sites forecast in 2020-2024 are shown in Figure 15(a), with those forecast in 2025-2029 shown in Figure 15(b). Figure 16(a) shows all potential sites in 2020-2024 that have suitable rates of return, while Figure 16(b) shows the same for 2025-2029.

Transmission connected solar has made the shortlist in 2020 Scenario ID 5 in this case because there is adequate GXP import capacity at the GXPs to which the model 'connects' the solar. This results in three suitable sites in this case (the shortlist). However, the number of potential sites where solar has a positive NPV (the longlist) is 104, which gives an indication of the viability of solar in the scenario. Most scenarios have many more potential solar sites than are included in the forecast. Table 7 illustrates this with the ratio of the number in the longlist to the number in the shortlist.

Table 7: Ratio of the number of potential solar systems on the longlist to the number on the shortlist from which the forecast is made.

(a) Production Scenario 0, where worldwide solar production slows from 2024.

ID	Name	2020-2024	2025-2029	2030-2034	2035-2039	2040-2044	2045-2049	2050-2054	2055-2059	2060-2064
0	New Normal Base Case	100 : 3	4901 : 16	10760 : 24	7627 : 3	2524 : 2	215 : 0			
1	New Normal Scenario One		1071 : 8	545 : 2	1 : 0					
2	New Normal Scenario Two	3117 : 13	25874 : 40	8946 : 9	980 : 0	349 : 1	176 : 3	92 : 1	44 : 1	22 : 0
3	EDGS Base Case		684 : 6	2280 : 6	3151 : 11	1925 : 11	174 : 1	2 : 0		
4	EDGS Scenario One			214 : 5	85 : 0					
5	EDGS Scenario Two	104 : 3	9375 : 33	19373 : 15	7218 : 11	2004 : 1	492 : 0	268 : 1	140 : 0	99 : 2
6	Reset Back Base Case			182 : 5	613 : 0	337 : 3	62 : 0	1 : 0		
7	Reset Back Scenario One									
8	Reset Back Scenario Two		960 : 8	6279 : 21	12396 : 15	9617 : 8	4660 : 11	2284 : 2	1186 : 0	510 : 0

(b) Production Scenario 1, where worldwide solar production slows from 2019.

ID	Name	2020-2024	2025-2029	2030-2034	2035-2039	2040-2044	2045-2049	2050-2054	2055-2059	2060-2064
0	New Normal Base Case	8 : 2	2323 : 10	4582 : 16	3769 : 9	1702 : 1	74 : 0			
1	New Normal Scenario One		326 : 5	267 : 0	1 : 0					
2	New Normal Scenario Two	2806 : 12	19630 : 34	12417 : 15	3297 : 2	620 : 0	295 : 1	174 : 1	106 : 0	52 : 1
3	EDGS Base Case		52 : 3	1028 : 5	469 : 2	563 : 1	45 : 0			
4	EDGS Scenario One									
5	EDGS Scenario Two	11 : 2	4409 : 14	14057 : 27	11454 : 10	5176 : 8	2303 : 1	711 : 1	334 : 0	210 : 1
6	Reset Back Base Case					140 : 4	98 : 1	12 : 0		
7	Reset Back Scenario One									
8	Reset Back Scenario Two		193 : 4	2089 : 8	5851 : 23	7892 : 8	8418 : 5	5193 : 5	3467 : 6	2136 : 3

By 2025-2029 the transmission connected solar forecast has grown to well over 1 GW in all but three scenarios (Table 5(a)). By this time, the capital cost of a utility-scale solar project has fallen substantially. Depending on the scenario, the revenue of the new set of potential utility-scale solar systems is not much more than that of the 2020 systems discussed above. However, the capital cost reduction more than offsets that, with some potential systems having very high NPVs. To illustrate this, the longlist of potential systems with positive NPVs in 2020 Scenario ID 5 (Figure 16(a)) grows from 104 possible systems to over 9,000 potential systems with positive NPVs in 2025 (Figure 16(b)), with just 33 selected into the shortlist based on GXP import capacity.

This illustrates how quickly potential utility-scale solar systems can become viable for development – in under five years the number of potential systems with adequate rates of return increased by a factor of nearly 100 in one scenario. While there are other economic factors that could change during this time, such as land price and availability and required rate of return, this demonstrates that the rate of growth of utility-scale solar is also very dependent on ongoing capital cost reductions. This in turn is dependent on the continuing growth of the worldwide PV industry.

There is also a wide variation between scenarios. For example, EDGS Scenario One (ID 4) shows delayed utility-scale solar development and limited capacity of nearly 1,000 MW by 2030. This is due to its high cost of capital, high land inflation and low electricity price inflation. By contrast EDGS Scenario Two (ID 5) shows rapid and extensive utility-scale solar development, reaching over 8,000 MW by 2030. Between these is the base case, reaching about 2,200 MW by 2030 (with solar sites shown in Figure 17). Given the sensitivities to inputs this is not surprising. The key point is that in two scenarios there is significant capacity development, and very rapid in one scenario.

The development is almost to the level of existing installed capacity of electricity generating plant in some scenarios. EDGS Scenario Two (ID 5) could produce nearly 13,000 GWh per annum by 2030, about 30% of New Zealand's current annual generation. EDGS Base Case (ID 3) could produce around 6,500 GWh per annum by 2035, about 15% of New Zealand's current annual generation.

The large capacity developments forecast in these scenarios only consider grid capacity, and do not consider other constraints already mentioned. It is doubtful whether the electricity generation and transmission system could accommodate so much utility-scale solar in terms of technical integration and managing and storing the daily and seasonal solar generation profile. Further, such a large influx of solar capacity may also depress the wholesale electricity price at times when solar is generating, negating the benefit brought about by the solar weighting factor. The reduction in location factor at a location from increased generation resulting in lower transmission losses is modelled. However, the model does not include the entire wholesale electricity market and the effect of increased generation on real-time wholesale price. For these reasons, the very high forecasts of Scenarios 0, 2, 3, 5 and 8 are unlikely to eventuate.

Finally, with the high forecast shown in EDGS Scenario Two (Scenario ID 5) we examine the influence of electricity price inflation on this. Such an influence is of interest in this scenario, as the low return required of 6.5% may become a reality in the near- to medium-term. However, a low electricity price inflation may accompany this. The input parameters of Scenario ID 5 (Production Scenario 0) were therefore left the same as given in Table 2, including the land and wage inflation, but the electricity price inflation was set to 0.5% per annum. The results are displayed in Table 8, and for 2020 were the same as those given in Table 5(a), as expected. The number on the longlist (solar sites with positive NPVs) in 2025 dropped from the 9,375 of Table 7(a) to 1,830, with large drops experienced in 2030 and 2035 as well. This is consistent with the high sensitivity of NPV to electricity price.

Next, we ran the same modified Scenario ID 5, but for Production Scenario 1, where the PV system cost does not fall as rapidly, nor by as much. The results of this are given in Table 9 and show an even more dramatic drop in numbers on the long list, and therefore capacity forecast. While the total forecast capacity is still reasonably high (1,620 MWp) it is lower than Production Scenario 0. This is because the general and wage inflation applied to module costs outpaces electricity price inflation, particularly in later years. This explains why what forecast potential there is occurs up to and including 2030, with none beyond then.

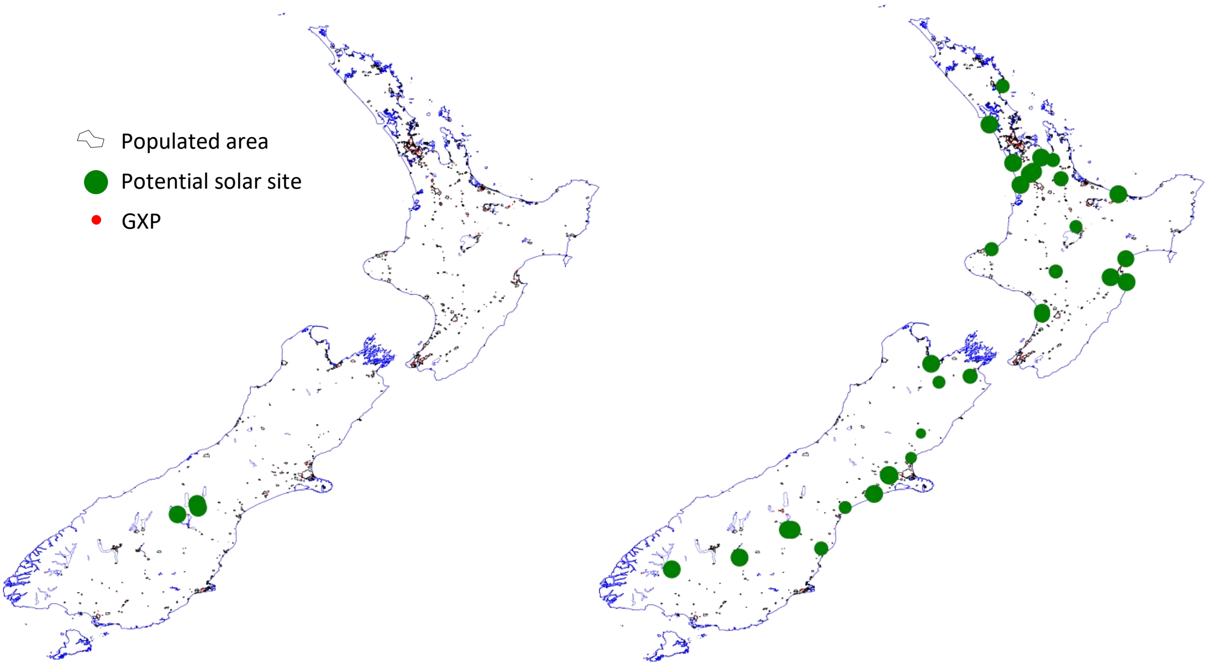
The conclusion from this is not surprisingly consistent with Section 2.4.2 - that the sensitivity of utility-scale solar forecasts is highly sensitive to electricity price, solar capital costs and rate of return requirement. Overall we conclude that utility-scale solar uptake may be muted if electricity prices fall in real terms in a low cost of capital environment, but if they remain stable or increase, utility-scale solar uptake could be very high. A similar conclusion is made for distribution connected solar, discussed in the next section.

Table 8: Examining the impact of reducing electricity price inflation (set to 0.5% per annum) in EDGS Scenario Two (Scenario ID 5, Production Scenario 0).

Production Scenario 0		2020	2025	2030	2035	2040	2045	2050	2055	2060	Total
Number on shortlist	Original Scenario ID 5	3	33	15	11	1	-	1	-	2	66
	Scenario ID 5 with 0.5% electricity price inflation, all other parameters the same	3	8	5	-	-	-	-	-	-	16
Number on longlist	Original Scenario ID 5	104	9,375	19,373	7,218	2,004	492	268	140	99	39,073
	Scenario ID 5 with 0.5% electricity price inflation, all other parameters the same	104	1,830	1,691	36	-	-	-	-	-	3,661
Forecast Capacity (MWp)	Original Scenario ID 5	583	5,403	2,159	1,398	140	-	60	-	158	9,900
	Scenario ID 5 with 0.5% electricity price inflation, all other parameters the same	583	1,414	997	-	-	-	-	-	-	2,994
Cumulative forecast capacity (MWp)	Original Scenario ID 5	583	5,986	8,145	9,543	9,683	9,683	9,743	9,743	9,900	
	Scenario ID 5 with 0.5% electricity price inflation, all other parameters the same	583	1,997	2,994	2,994	2,994	2,994	2,994	2,994	2,994	

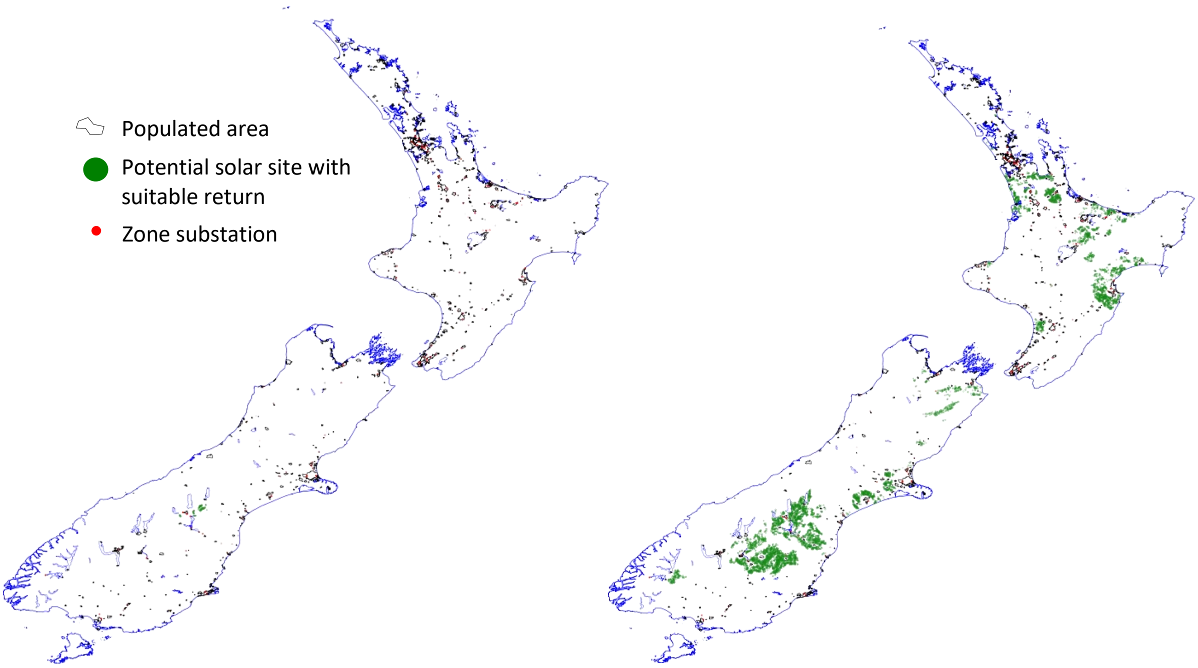
Table 9: Examining the impact of reducing electricity price inflation (set to 0.5% per annum) in EDGS Scenario Two (Scenario ID 5, Production Scenario 1).

Production Scenario 1		2020	2025	2030	2035	2040	2045	2050	2055	2060	Total
Number on shortlist	Original Scenario ID 5	2	14	27	10	8	1	1	-	1	64
	Scenario ID 5 with 0.5% electricity price inflation, all other parameters the same	2	6	1	-	-	-	-	-	-	9
Number on longlist	Original Scenario ID 5	11	4,409	14,057	11,454	5,176	2,303	711	334	210	38,665
	Scenario ID 5 with 0.5% electricity price inflation, all other parameters the same	11	1,061	155	-	-	-	-	-	-	1,227
Forecast Capacity (MWp)	Original Scenario ID 5	327	2,612	4,013	1,459	1,038	40	140	-	60	9,690
	Scenario ID 5 with 0.5% electricity price inflation, all other parameters the same	327	1,094	199	-	-	-	-	-	-	1,620
Cumulative forecast capacity (MWp)	Original Scenario ID 5	327	2,939	6,953	8,412	9,450	9,490	9,630	9,630	9,690	
	Scenario ID 5 with 0.5% electricity price inflation, all other parameters the same	327	1,422	1,620	1,620	1,620	1,620	1,620	1,620	1,620	



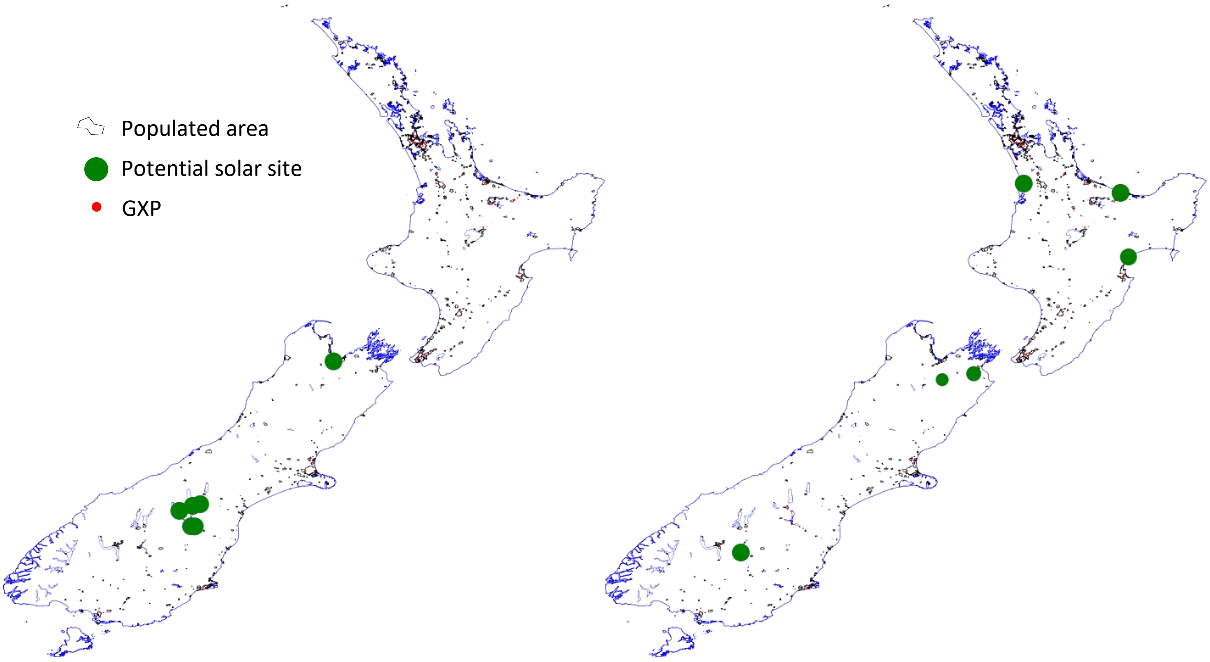
(a) (b)

Figure 15: Transmission connected utility-scale solar forecast in the EDGS Scenario Two (Scenario ID 5), Production Scenario 0 – the solid blue bar in Figure 13. (a) 2020-2024; (b) 2025-2029. This scenario output gives an indication of the first transmission connected solar system locations with the highest rate of return and that are within transmission grid capacity.



(a) (b)

Figure 16: EDGS Scenario Two (Scenario ID 5), Production Scenario 0 potential transmission connected solar system locations with suitable rates of return. (a) 2020-2024 (104 of 43,207 potential sites); (b) 2025-2029 (9,375 of 43,207 potential sites). This gives an indication of the first potential transmission connected solar system locations with suitable rates of return.



(a) (b)

Figure 17: Transmission connected utility-scale solar forecast in the EDGS Base Case (Scenario ID 3), Production Scenario 0 – the solid green bar in Figure 13. (a) 2025-2029; (b) 2030-2034.

3.2 Distribution connected utility-scale solar forecast

The distribution connected utility-scale solar capacity forecast for the three EDGS scenarios is shown in Figure 18, with the energy forecast shown in Figure 19. As before, the solid bars are derived from the higher worldwide solar module production forecast (Production Scenario 0) while the patterned bars are derived from the lower worldwide solar production (Production Scenario 1). The forecasts are tabulated in Table 10 for all price and production scenarios.

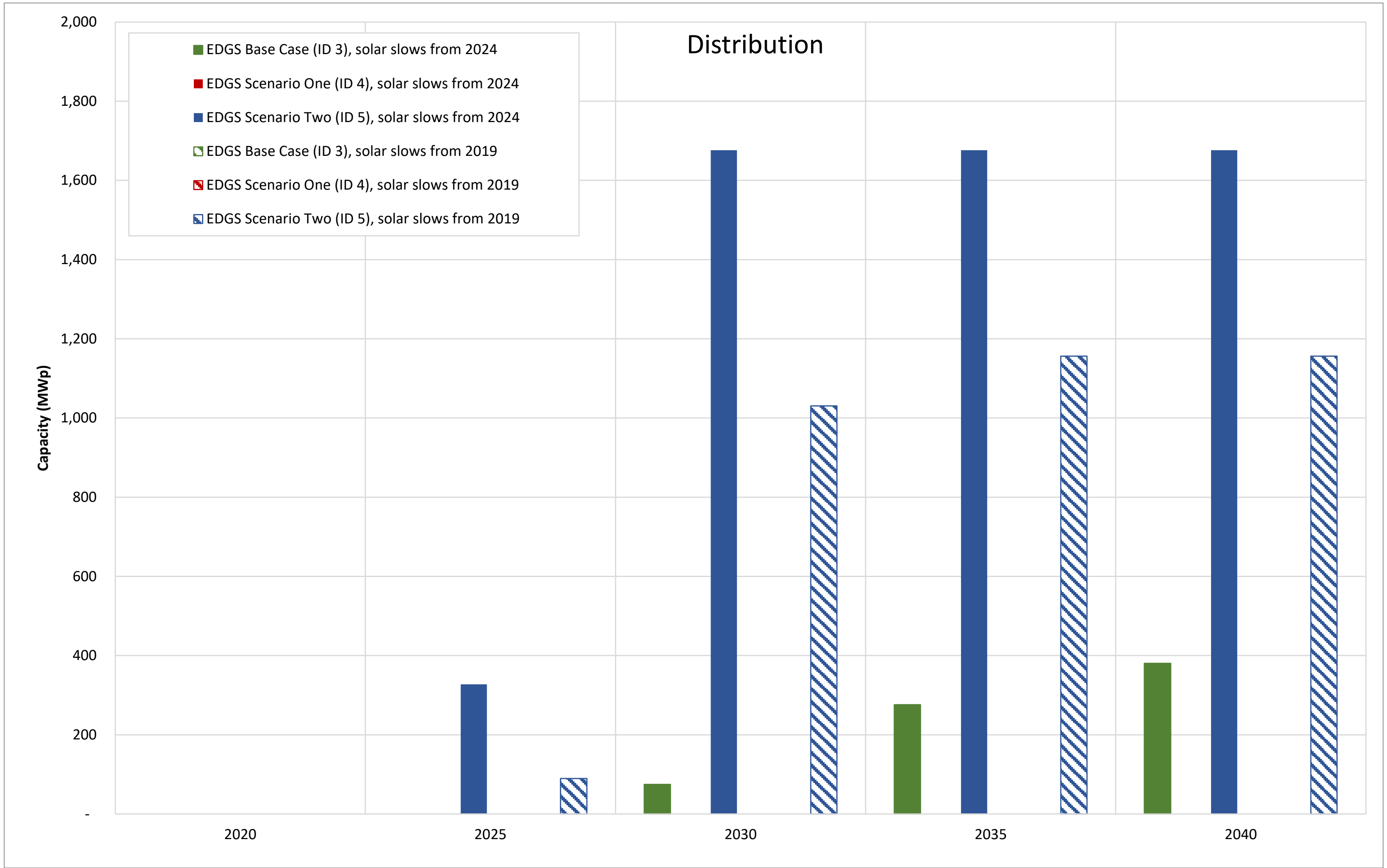


Figure 18: Distribution connected cumulative solar system capacity. In each scenario these show a rapid rise then tapering off as the distribution network capacity is reached.

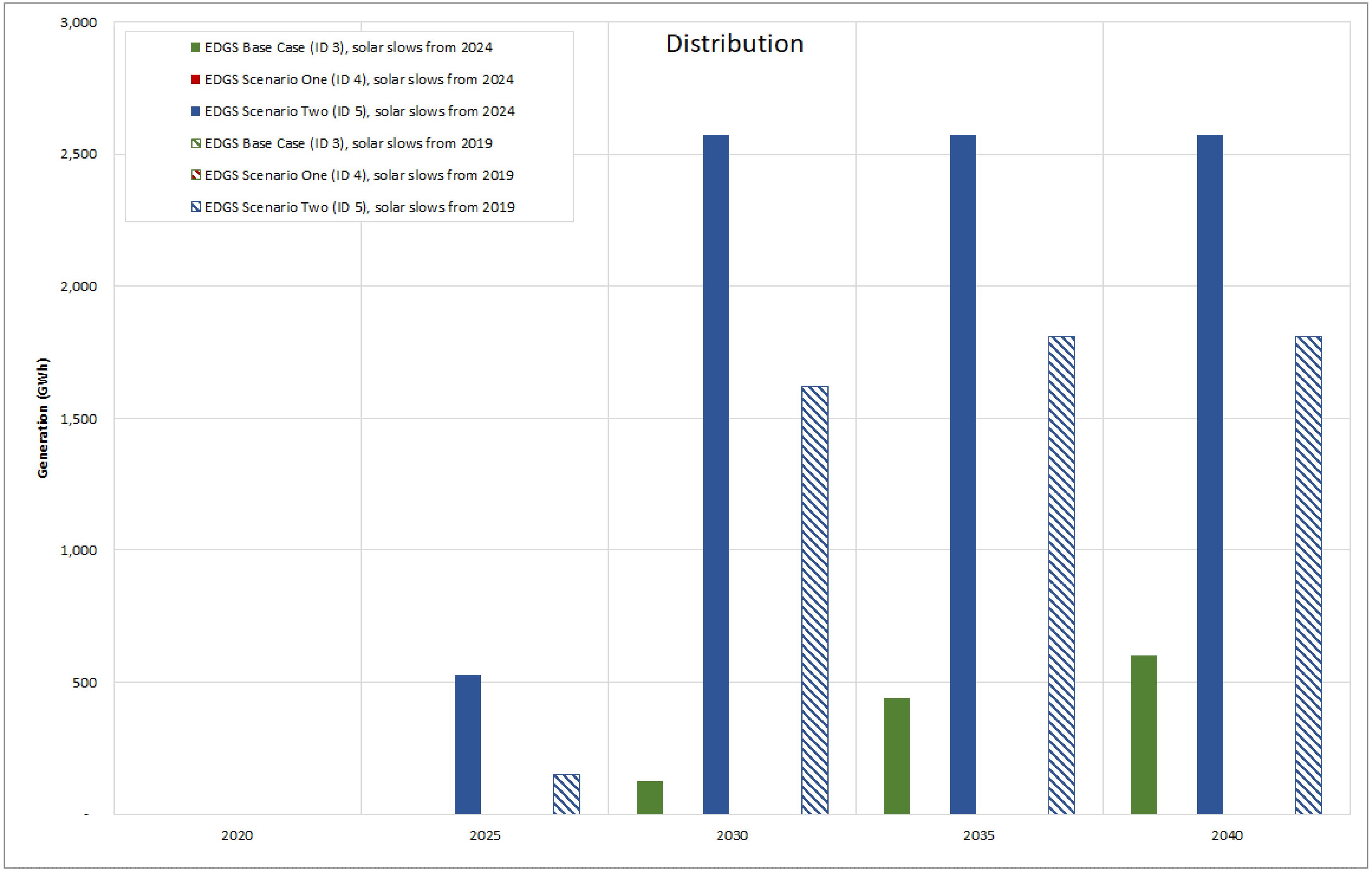


Figure 19: Distribution connected solar system annual generation.

Table 10: Distribution connected total solar system capacity forecast (MWp).

(a) Production Scenario 0, where worldwide solar production slows from 2024

ID	Name	2020-2024	2025-2029	2030-2034	2035-2039	2040-2044	2045-2049	2050-2054	2055-2059	2060-2064	Total
0	New Normal Base Case	-	110	799	32	-	-	-	-	-	941
1	New Normal Scenario One	-	-	-	-	-	-	-	-	-	-
2	New Normal Scenario Two	32	2,217	-	-	-	-	-	-	-	2,249
3	EDGS Base Case	-	-	75	201	105	-	-	-	-	380
4	EDGS Scenario One	-	-	-	-	-	-	-	-	-	-
5	EDGS Scenario Two	-	327	1,349	-	-	-	-	-	-	1,676
6	Reset Back Base Case	-	-	-	-	-	-	-	-	-	-
7	Reset Back Scenario One	-	-	-	-	-	-	-	-	-	-
8	Reset Back Scenario Two	-	-	364	906	-	-	-	-	-	1,271

(b) Production Scenario 1, where worldwide solar production slows from 2019.

ID	Name	2020-2024	2025-2029	2030-2034	2035-2039	2040-2044	2045-2049	2050-2054	2055-2059	2060-2064	Total
0	New Normal Base Case	-	-	165	141	4	-	-	-	-	310
1	New Normal Scenario One	-	-	-	-	-	-	-	-	-	-
2	New Normal Scenario Two	13	1,387	67	-	-	-	-	-	-	1,468
3	EDGS Base Case	-	-	-	-	-	5	-	-	-	5
4	EDGS Scenario One	-	-	-	-	-	-	-	-	-	-
5	EDGS Scenario Two	-	89	941	126	-	-	-	-	-	1,156
6	Reset Back Base Case	-	-	-	-	-	-	-	-	-	-
7	Reset Back Scenario One	-	-	-	-	-	-	-	-	-	-
8	Reset Back Scenario Two	-	-	14	270	469	53	-	-	-	805

Evident from the forecast results is a rapid rise in distribution connected utility-scale solar capacity in the first 10-20 years, after which it tapers off with no further installations. This is primarily due to the network and zone substation capacity being reached. For example, in Scenario ID 5 and by 2030 there are more than 13,000 potentially viable distribution connected solar projects, but only about 290 are within the network or zone substation capacity.

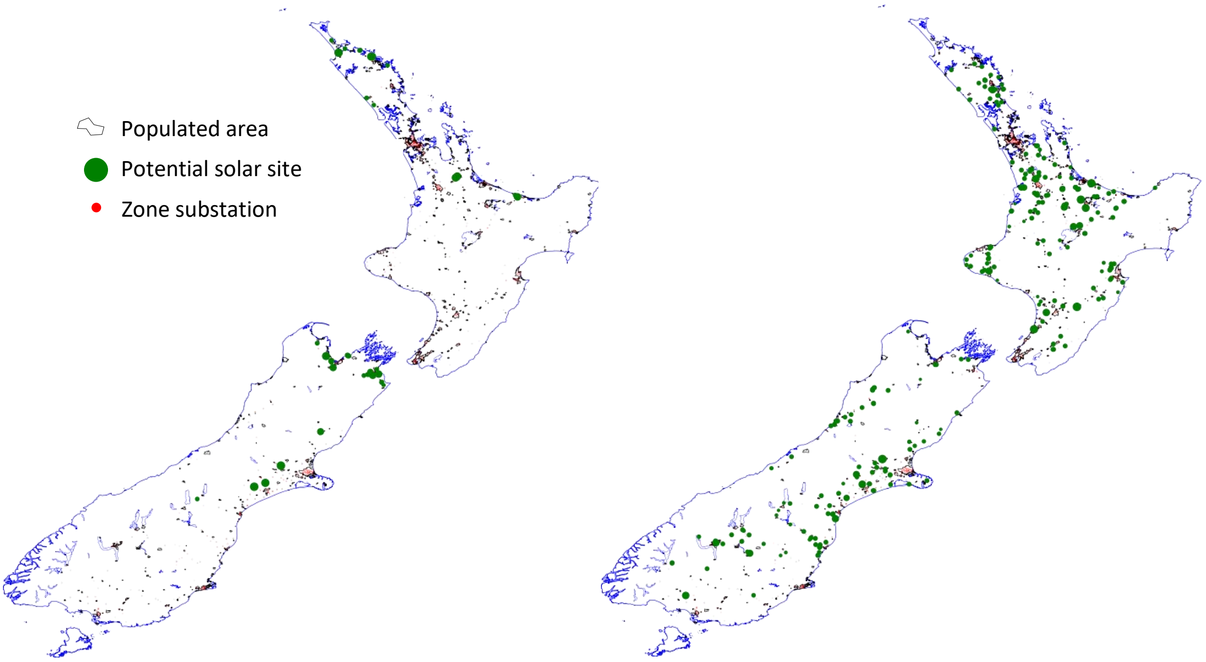
One scenario (ID 2) shows distribution connected solar forecast in 2020. This scenario output gives an indication of the first utility-scale solar locations with the highest rate of return – all in the Tasman, Marlborough and Far North districts. Figure 20 shows the EDGS Scenario Two (ID 5) solar systems, which are also at these locations and others in later years. Figure 21 shows all potential distribution connected solar sites in the same scenario and years. This also illustrates how rapidly distribution connected solar can become viable.

Given the large number of forecasted distribution connected solar sites in the Far North it is curious why there are no forecast transmission connected solar systems in the Far North. This is because the GXP in the Far North has limited import capacity. Therefore, the model attempts to 'build' a transmission line to the south which becomes prohibitively expensive.

As with Transmission, the effect of reducing the electricity price inflation to 0.5% in the EDGS Scenario Two (Scenario ID 5), while keeping all other parameters the same, was investigated for distribution connected solar. In the case of Production Scenario 1 it reduced the cumulative capacity to 1,225 MWp from 1,676 MWp, all of which is forecast for 2030. This is shown in Table 11. The same was tested with Production Scenario 1 which shows no solar forecast in any year.

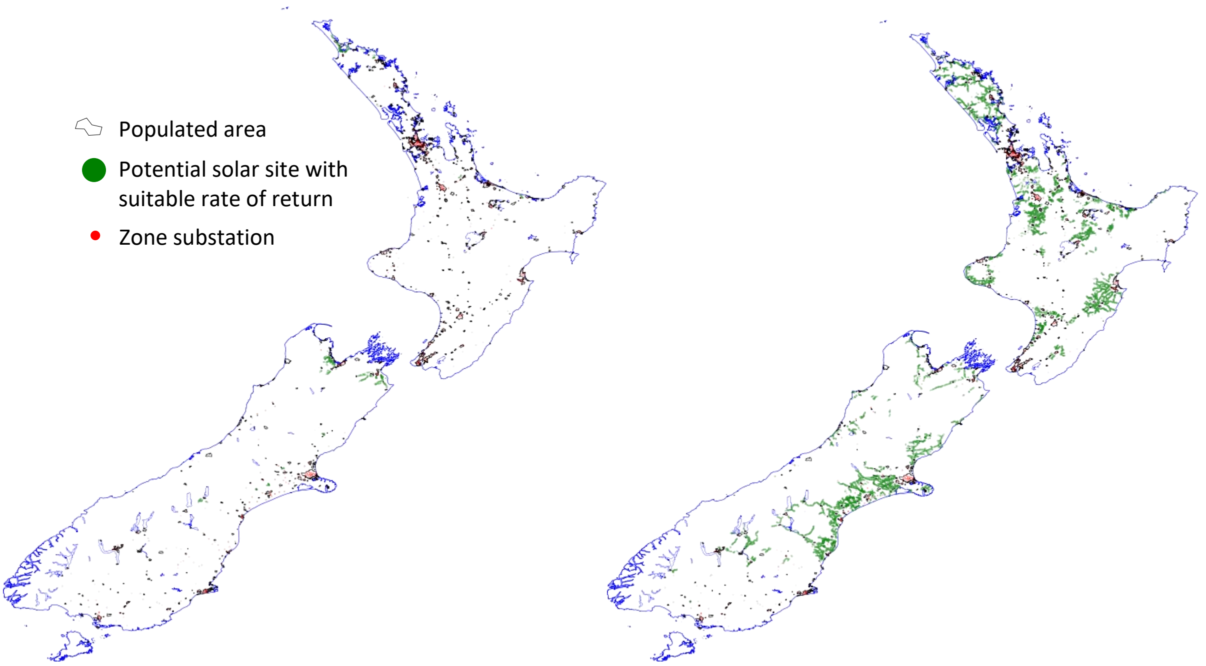
Table 11: Examining the impact of reducing electricity price inflation (set to 0.5% per annum) in EDGS Scenario Two (Scenario ID 5, Production Scenario 0).

Production Scenario 0		2020	2025	2030	2035	2040	2045	2050	2055	2060	Total
Number on shortlist	Original Scenario ID 5	-	38	255	-	-	-	-	-	-	293
	Scenario ID 5 with 0.5% electricity price inflation, all other parameters the same	-	1	13	-	-	-	-	-	-	14
Number on longlist	Original Scenario ID 5	-	566	12,569	-	-	-	-	-	-	13,135
	Scenario ID 5 with 0.5% electricity price inflation, all other parameters the same	-	1	170	-	-	-	-	-	-	171
Forecast Capacity (MWp)	Original Scenario ID 5	-	327	1,349	-	-	-	-	-	-	1,676
	Scenario ID 5 with 0.5% electricity price inflation, all other parameters the same	-	-	1,225	-	-	-	-	-	-	1,225
Cumulative forecast capacity (MWp)	Original Scenario ID 5	-	327	1,676	1,676	1,676	1,676	1,676	1,676	1,676	
	Scenario ID 5 with 0.5% electricity price inflation, all other parameters the same	-	-	1,225	1,225	1,225	1,225	1,225	1,225	1,225	



(a) (b)

Figure 20: EDGS Scenario Two (Scenario ID 5), Production Scenario 0 forecast – the solid blue bar in Figure 18. (a) 2025-2029; (b) 2030-2034. This scenario output gives an indication of the first distribution connected solar system locations of Scenario ID 5 with the highest rates of return and that are within the distribution network capacity.



(a) (b)

Figure 21: EDGS Scenario Two (Scenario ID 5), Production Scenario 0 potential distribution connected solar system locations with suitable rates of return. (a) 2025-2029 (566 of 33,092 potential sites); (b) 2030-2034 (12,569 of 33,092 potential sites). This gives an indication of all potential distribution connected solar system locations with suitable rates of return in this scenario.

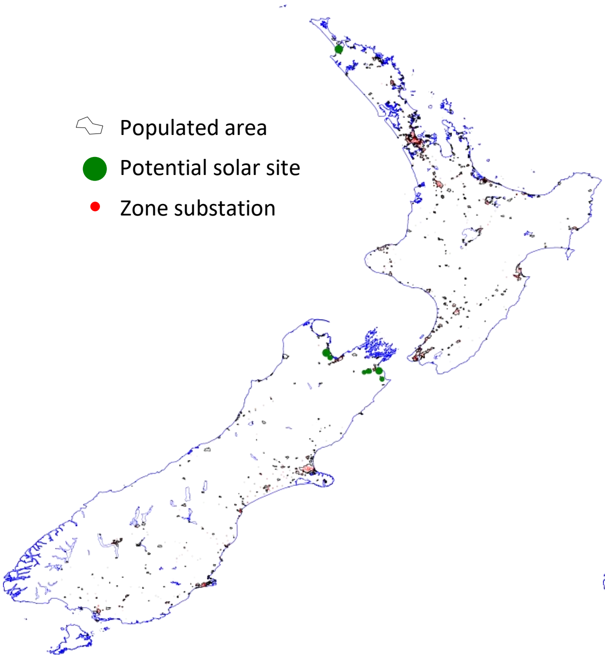


Figure 22: EDGS Base Scenario (Scenario ID 3), Production Scenario 0 forecast – the solid green bar in Figure 18. (a) 2030-2034; (b) 2035-2039. This scenario output gives an indication of the first distribution connected solar system locations of Scenario ID 3 with the highest rates of return and that are within the distribution network capacity.

3.3 Discussion

Evident from the forecasts is the potential for extensive solar development in some scenarios, even with transmission and distribution capacity constraints accounted for. It may be questionable whether the wider electricity system could accommodate such solar capacity (for example, in terms of technical integration and managing and storing the daily and seasonal solar generation profile). However, as mentioned above, a rapid rate of growth when the balance tips towards utility-scale solar systems becoming economic suggests the need for preparedness by network owners and operators.

When considering the forecasts in this report the following should be considered alongside them:

1. The forecasts must be viewed in conjunction with possible medium- to long-term electricity infrastructure changes. Infrastructure changes that will permanently increase or lower price and/or location factors are particularly important.

2. The large influx of solar capacity shown in some forecasts may also depress the wholesale electricity price at times when solar is generating, negating the incentive to develop a utility-scale solar project. While the forecasts do incorporate the reduction in location factor at a location from increased generation resulting in lower transmission losses, they do not incorporate the entire wholesale electricity market, and the effect of increased generation on real-time wholesale price. For these reasons, the very high forecast scenarios (the blue bar in the above chart / Scenarios 0, 2, 3, 5 and 8 in the report) are unlikely to eventuate.

3. The rates of return of utility-scale solar projects in other jurisdictions may be greater than what can be achieved in New Zealand. Solar projects in countries with better solar resource, such as Australia, California, the Middle East and northern Africa will produce more energy, potentially increasing rates of return. This is relevant, as the forecasts are based on utility-scale solar projects meeting an acceptable rate of return. For this reason, a range of rates of return are tested in the scenarios.

4. However, as solar development becomes saturated in other countries, investors/developers may look to New Zealand for development. Even if those countries are a long way off saturation, increasing solar deployment will drive more module production, reducing PV system prices further and thereby increasing rates of return in New Zealand. As discussed earlier, utility-scale solar forecasts are very sensitive to capital cost.

5. There is also the possibility that cost of capital will decrease substantially in the near- to medium-term largely as a result of the coronavirus (COVID-19) pandemic declared while this study was being conducted. Consideration was given to adjusting some scenario parameters to account for economic disruption from the pandemic. However, this is a long-term study to 2060. Therefore, the parameters were retained, and the scenarios provide some coverage of possible macro-economic outcomes from the pandemic, specifically lower cost of capital.

   Countering cost of capital reductions could be disruptions to supply chains of solar equipment resulting from the pandemic, possibly increasing its capital cost. While investigations of more recent capital costs (Feldman & Margolis, August 2019) show ongoing reductions in PV module and inverter costs exceeding those used in this study, more recent data was not available at the time of writing to understand the impacts from the pandemic.

6. The lifespan and analysis of utility-scale solar used in this study was 25 years. This is a conservative assumption, as lifespans of modern modules are more likely to be in the range of 30 years, but they may attract a price premium.

7. Since many PV components are imported, fluctuations in the New Zealand dollar could change the cost of systems in New Zealand. This may counter reducing rate of return requirements, although other generation technologies are likely to be similarly affected by exchange rate fluctuations.

8. Ongoing advances in other generation technologies, such as wind and geothermal, may see reductions in their capital costs. In turn they will continue to compete with utility-scale solar, and therefore the very large forecasts indicated in this report may not eventuate.

9. Losses and soiling of PV panels is accounted for. However, some of the solar projects are in areas and at altitudes where snow cover may reduce capacity factor. Nevertheless, the number of potential sites on the longlist in these areas covers projects at lower altitudes and less likely to have significant snow cover. Therefore, this is not expected to change the forecasts.

As shown in the results, there is considerable variation in solar capacity between the scenarios, some of which may not be possible due to wider energy system constraints. However, one of the key findings from this study is how rapidly solar development could occur in New Zealand once it starts. For example, several gigawatts of development in the space of 5-10 years. It was shown that solar returns are very sensitive to electricity price. Further investigation of solar forecast shows that reducing electricity price inflation to a low figure (where the real price of electricity declines) has a large impact on the forecasts, as does reducing the required rate of return and PV system capital cost. Utility-scale solar uptake is particularly sensitive to electricity price, required rate of return and ongoing PV system capital cost reductions. If PV system costs do not reduce as much as predicted in the future, the capacity of utility-scale solar development will be lower, but the development is still forecast to occur in the next 10-15 years.

4. Appendix – Developing the capital cost component model into a time series

In developing a time series of capital cost, the simple approach of adjusting by annual inflation for each component was not suitable, as it does not take into account the 'learning curve' (also known as the 'learning rate', or 'experience curve') of increasing production. This is where manufacturers become better at producing a good, or offering a service over time, which results in cost reductions. Therefore, the learning curve of solar for each doubling of the level of production was investigated. Studies that examined not just PV modules, essentially a commodity item and subject to a steep learning curve, but balance of system (BOS) components also, were sought. Two studies were found: (Elshurafa, Albardi, Bigerna, & Bollino, 2018) and (Cengiz & Mamis, 2015). Fraunhofer (2019) also provided insights into module learning curves. Elshurafa et al (2018) derived learning curves by country for both modules and BOS, although results mainly focused on residential systems. In this study we also undertook analysis of PV system costs over time from NREL's data (Fu et al. 2018).

Since the learning curve relates cost reduction to doubling in production, and it was a requirement to know cost as a time series by year, it was necessary to determine the doubling rate of PV production and convert learning curves to an annual cost reduction. The primary data source to determine this was Fraunhofer (2019) for annual module production from 2005 to 2018. Worldwide installations were also examined from 2008 to 2018 from the Renewables Now REN21 report (REN21, 2019). A comparison of these showed that installation capacity by year, as reported in REN21 (2019) closely matched production by year, as reported by Fraunhofer (2019). Moreover, the REN21 (2019) data agreed with the International Energy Agency (IEA) Strategic PV Analysis and Outreach 2019 report (IEA, 2019).

Figure 23 shows the Fraunhofer (2019) worldwide PV module production from 2010 to 2018. Fitting a curve $p = a2^{by}$ to this, as shown, gives a doubling time, $\frac{1}{b}$, equal to 3.68 years. The doubling time from 2005 to 2018 was even shorter. However, data prior to 2010 was not used, as earlier years showed exceptionally large increases from a smaller base and was pre the global financial crisis of 2008. Since the installation capacity by year is almost identical to the production capacity, it is assumed that the doubling time for modules also applies to other components, such as inverters, installation etc. This will not be entirely accurate, as there are different systems installed, ranging from residential, to commercial, to utility-scale.

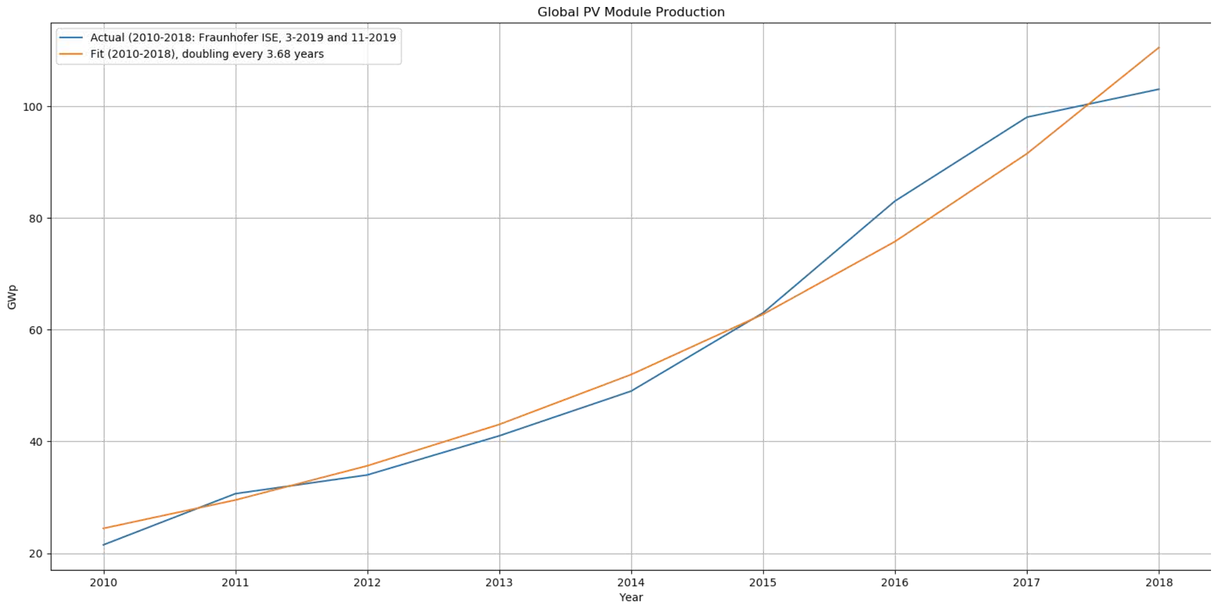


Figure 23: Worldwide PV module production. Data from 2005 to 2009 was also examined, which showed a shorter production doubling time; more recent and post global financial crisis data was therefore used.

Once we know the learning curve for each component, the cost at any period over which production doubles can be determined according to:

$$C_n = C_0 LC_i^n$$

where C_0 is the cost ($/W) at year 0;

C_n is the cost at period n over which production doubles; and

LC_i is the learning curve for component i contributing to the overall PV system cost.

This is converted to an annualised learning curve, $\widehat{LC_\iota}$, necessary to derive a time series of cost at any year, y, in the future according to $C_y = C_0 \widehat{LC}_i^y$. The annualised learning curve is given by $\widehat{LC_\iota} = LC_i^b$, where b is the exponential coefficient from the earlier expression, equal to the inverse of the time (in years) taken for production to double.

Before considering annualised learning curve values ($\widehat{LC_\iota}$), learning curves relating to production doubling times (LC_i) are explored for each component. Analysis of learning curves from data for each component by Miller (2020c) gives learning curves of 35% for modules (i.e. cost reduces by 65% for each doubling in production); 43% for inverters; 57% for structural and electrical balance of system components; 46% for installation labour; and 58% for other soft costs.

Comparison is made with total cumulative installations, Table B2 of the Elshurafa et al. paper on this subject (Elshurafa, Albardi, Bigerna, & Bollino, 2018). For countries such as Australia this gives a minimum learning curve of 84% for all BOS components with the lowest reliable figure being 68.9% for Sweden. The minimum USA figure is 81.5% and Germany is 89.1%. Clearly the learning curves determined in Miller (2020c) from reported data are substantially lower.

The New Zealand PV solar industry is relatively immature, and may gain significant cost reductions over time, especially for utility-scale, as economies of scale improve, and the industry becomes more competitive. This is likely to improve installation labour costs, and potentially permitting and engineering, procurement and construction (EPC) costs, but the structural, electrical and inverter components are likely to be mainly imported. Therefore, the international balance of system figures is more likely to apply. Hence, this study uses 80% for the electrical and structural components and inverters, significantly higher than the learning curves determined in Miller (2020c) from reported data. This is closer to that of Australia, but still lower, to reflect some improvements from increased competition and economies of scale. A higher learning curve of 80% is also used for the soft costs of installation labour and 80% for other, also more similar to the Australian figure. The module learning curve is increased to 75%, which is still lower than the 80% for the other components, but consistent with Fraunhofer (2019). The learning curves are summarised in Table 12.

Table 12: Learning curves adopted in the model.

Component	Learning Curve (time invariant)
Soft costs - others	0.8
Soft costs - install labour	0.8
Hardware BOS - structural and electrical	0.8
Inverter	0.8
Module	0.75

4.1 Cumulative module production

Given the learning curves for each category, it remains to forecast future doubling rates of PV growth, since it cannot continue to double at the same rate forever. According to the IEA (October 2019) renewable capacity is set to expand by 50% between 2019 and 2024, led by solar PV. Of this increase of 1,200 GW, solar PV alone accounts for almost 60% of the expected growth, equating to 720 GW (IEA, October 2019). To achieve this, the production of solar would need to increase such that 720 GW was produced between 2020 and 2024. At the current rate of increase of production, determined to double every 3.68 years, this cumulative total from 2020 to 2023 of 720 GW would be achieved before 2023. We therefore leave the doubling time at 3.68 years until 2023, at which time it is gradually increased to double in production every 7.35 years over a 10 year span (the new doubling time, ytd', is achieved by multiplying the doubling time of the previous year, ytd, according to $ytd' = ytd.2^{1/10}$). This rate change continues each year, as shown in Table 13(a).

With this new rate the cumulative PV module production is shown in Figure 24 (the same as Figure 6 in the main report). As shown in Figure 24, by 2024, the worldwide cumulative capacity of solar PV reaches 1,640 GWp in Scenario 0. This is enough capacity to generate about 2,400 TWh, roughly 10% of 2017's worldwide electricity consumption[8]. The case of module production beginning to slow earlier than 2023 is also examined, leading to a second set of production doubling times given in Table 13(b). In this case production begins to slow from 2019, at the same rate as Table 13(a).

[8] From consumption data obtained from IEA (September 2019).

Table 13: Production doubling times (years).

(a) *Production Scenario 0 below (PV module production continues at the 2010-2018 doubling time of 3.68 years to 2023, doubling every 10 years from 2024).*

Production Scenario 0								
Year range	2018 - 2023	2024 - 2033	2034 - 2043	2044 - 2053	2054 - 2063	2064 - 2073	2074 - 2083	2084 - 2085
Time for production to double, *ytd* (years)	3.68 - 3.68	3.9 - 7.4	7.9 - 14.7	15.8 - 29.4	31.5 - 58.8	63 - 117.6	126.1 - 235.3	252.2 - 270.3

(b) *Production Scenario 1 below (PV module production begins to slow from the 2010-2018 doubling time of 3.68 years from 2019, doubling every 10 years from 2019).*

Production Scenario 1								
Year range	2018 - 2023	2024 - 2033	2034 - 2043	2044 - 2053	2054 - 2063	2064 - 2073	2074 - 2083	2084 - 2085
Time for production to double, *ytd* (years)	3.68 - 5.2	5.6 - 10.4	11.1 - 20.8	22.3 - 41.6	44.6 - 83.2	89.2 - 166.4	178.3 - 332.7	356.6 - 382.2

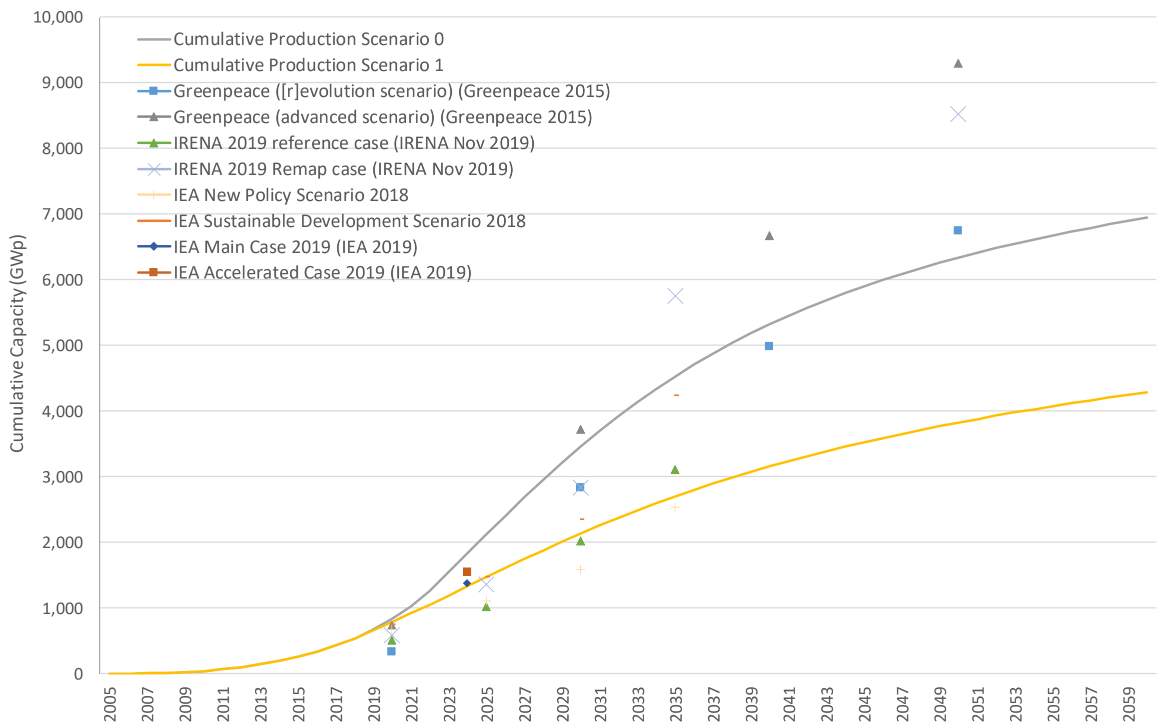


Figure 24: Cumulative worldwide PV module production.

To understand whether the cumulative production forecasts of Figure 24 are reasonable they are compared with a number of worldwide cumulative capacity projections, some usefully summarised by Jäger-Waldau (2019) in Table 1 (Jäger-Waldau, 2019), with others such as Greenpeace's (Greenpeace, 2015), IRENA's (IRENA, November 2019) and the 2019 IEA's (IEA, October 2019) directly from those sources. All forms of solar installations, which give rise to PV module production, are of interest. The Greenpeace [r]evolution scenario generally tracks closely to the Production Scenario 0, whereas the Greenpeace advanced scenario and IRENA 2019 Remap case are well above it. In earlier years, to 2035, the IRENA reference case is closer to Production Scenario 1, as is the IEA 2018 New Policy Scenario produced in 2018. Even earlier, in 2024, the recently released IEA main case is very close to Production Scenario 1, whereas the accelerated case is between Production Scenario 1 and Production Scenario 0.

Thus, it is concluded that the production rates of Production Scenario 0 in Figure 24 compare favourably with other projections, or could even be considered more conservative. Production Scenario 1 is generally below other projections, particularly those further out. Production Scenario 0 is therefore used in the forecasts, with Production Scenario 1 used to understand the sensitivity of the forecasts to worldwide PV module production.

4.2 Developing the capital cost component model into a time series with learning curves

Inflation, using the rates given in each scenario (Table 2), is also used to increment the cost of each item annually to reflect, in particular, the growing labour component in solar. The selection of higher learning curves than determined from reported data (Miller 2020c), and the inclusion of inflation, will result in slower capital cost reductions of PV over time, and therefore a more conservative PV uptake forecast.

The two Production Scenarios (0 and 1) are then combined with the annualised learning curves of Miller (2020c) to ascertain a time series of PV system component, and therefore total capital costs. Each PV system component from Table 3 is treated in the following way:

Table 14: Treatment of each PV capital cost component to derive time series of capital costs.

Component	Treatment
Developer net profit	Removed - covered in the required rate of return
Contingency	Decreased at each year by the annualised learning curve (Soft costs - others) and increased by general price inflation
Developer overhead	Decreased at each year by the annualised learning curve (Soft costs - others) and increased by general price inflation
Transmission line	Removed - covered separately in the model
Interconnection fee	Removed - covered separately in the model
Permiting fee	Decreased at each year by the annualised learning curve (Soft costs - others) and increased by general price inflation
Land acquisition	Removed - covered separately in the model
Sales tax	Removed - all costs are excluding GST
EPC overhead	Decreased at each year by the annualised learning curve (Soft costs - install labour) and increased by wage inflation
Install labour and equipment	Decreased at each year by the annualised learning curve (Soft costs - install labour) and increased by wage inflation
Electrical BOS	Decreased at each year by the annualised learning curve (Hardware BOS - structural and electrical) and increased by general price inflation
Structural BOS	Decreased at each year by the annualised learning curve (Hardware BOS - structural and electrical) and increased by general price inflation
Inverter only	Decreased at each year by the annualised learning curve (Inverter) and increased by general price inflation
Module	Decreased at each year by the annualised learning curve (Module) and increased by general price inflation

The resulting PV system capital costs, for all scenarios where general inflation is 2% and wage inflation 3%, are shown in Figure 7 (Production Scenario 0) and Figure 8 (Production Scenario 1). Figure 25 and Figure 26 show the real capital costs for Production Scenarios 0 and 1 respectively. Figure 9 shows the make-up of the PV solar system capital costs at various system sizes and times. This shows that as size increases module costs take on a larger share of the system cost. Module share of total capital cost reduces over time as balance of system costs, labour in particular, decrease at a slower rate than module costs.

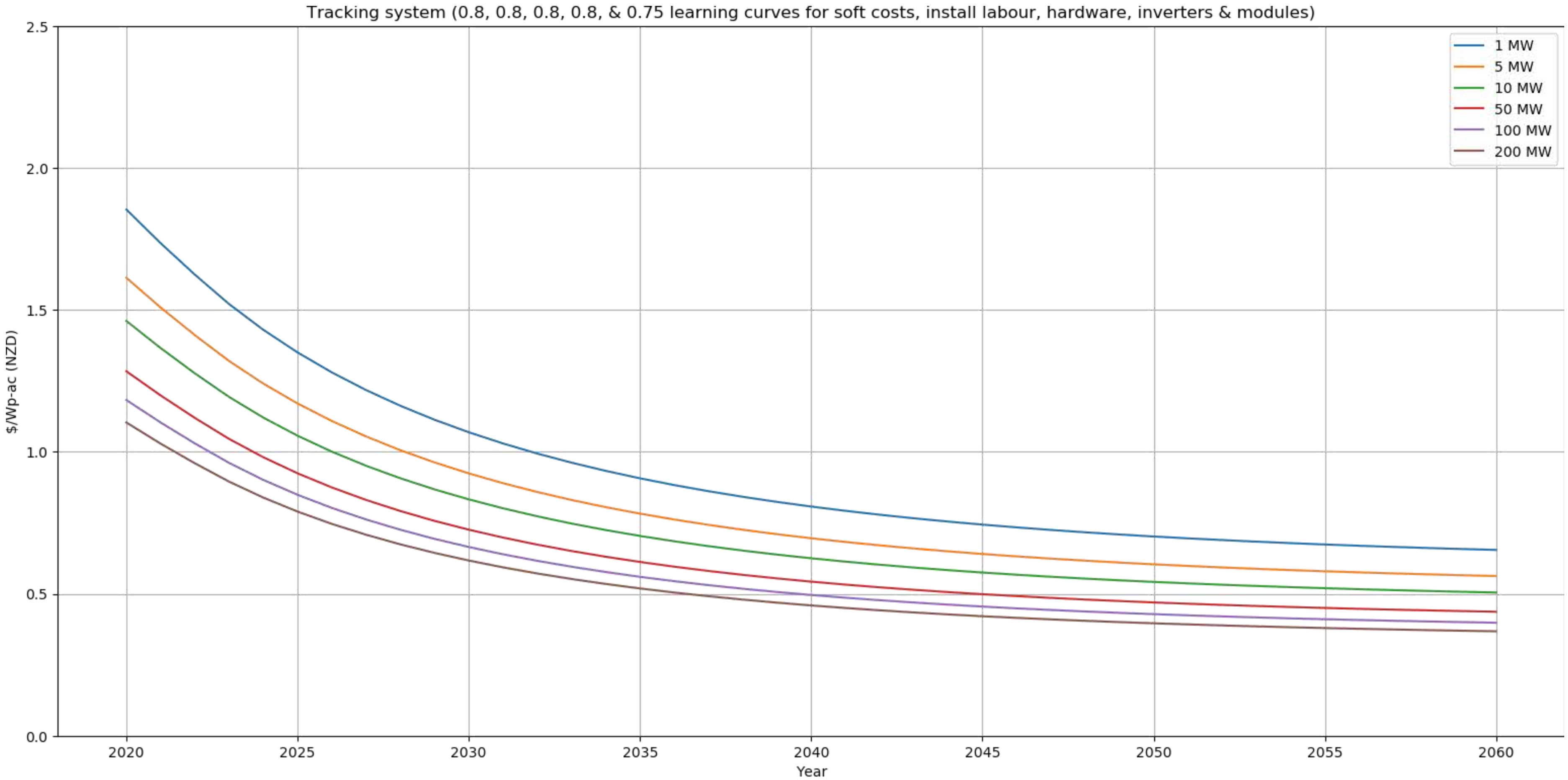


Figure 25: Tracking PV system capital costs (real), Production Scenario 0.

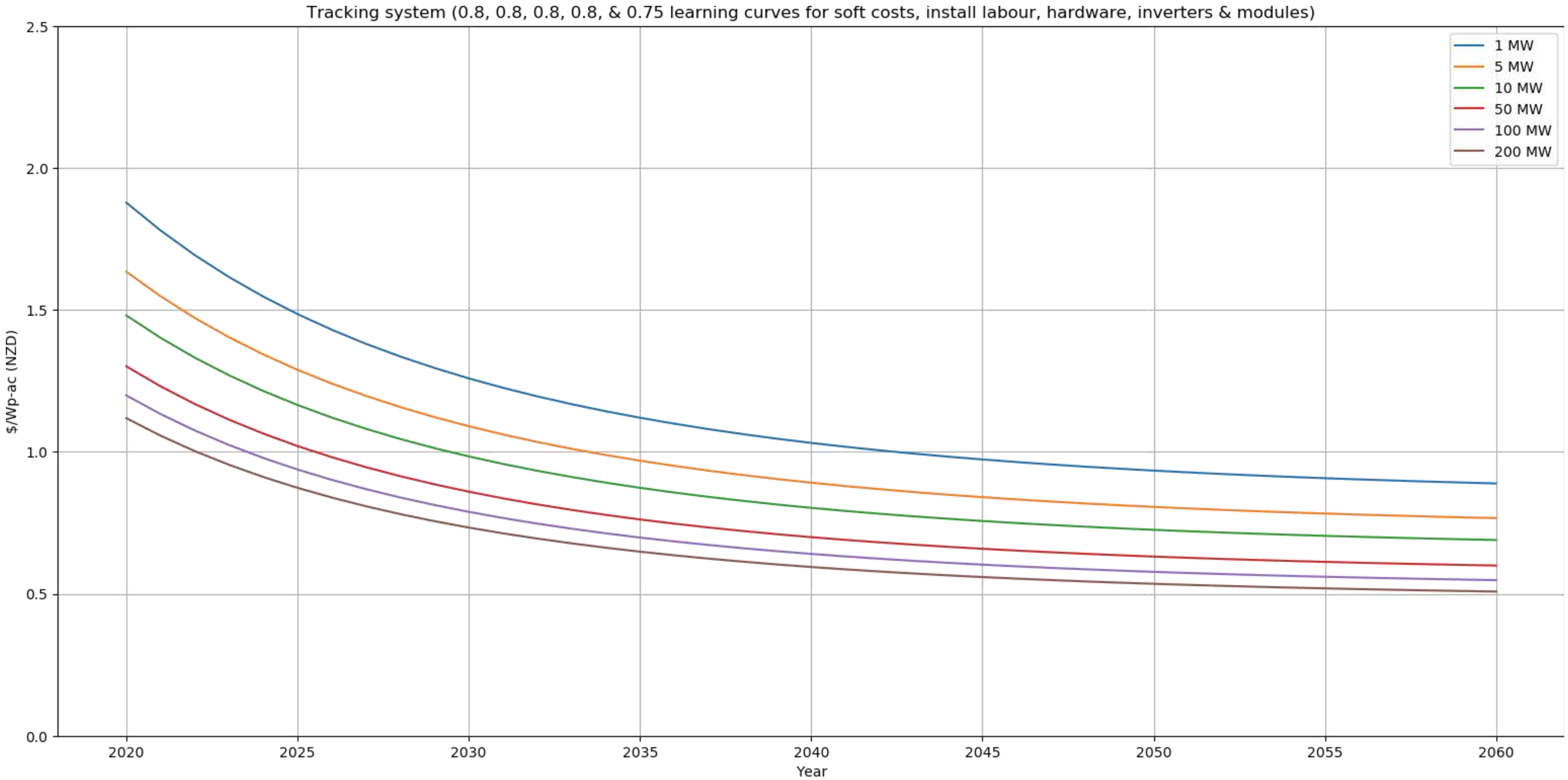


Figure 26: Tracking PV system capital costs (real), Production Scenario 1.

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