Memo

To	Lynley Fletcher, Environmental Manager, Meridian Energy Limited
From	Thomas Brent Layton
Date	16 June 2026
Subject	Meridian Energy Limited's Application for Western Bays Solar Farm to be referred in accordance with Section 13 of the Fast-track Approvals Act 2024

Qualifications and experience of author

My full name is Thomas Brent Layton.

I have been involved in the design and regulation of the electricity market since 1994.

I was the chair of the Rules Committee that designed the original market, director of the company that initially ran the market as a multi-lateral contract, chair of the advisory group for the Ministerial Review of the market that produced the Brownlee Reforms in 2010, and chair of the Electricity Authority for 10 years until October 2020.

I have been involved in providing economic advice on consenting 17 different generation projects across New Zealand. I was also engaged by iwi and farming groups to advise on the cap and trade nitrate emissions scheme that supports water clarity in Lake Taupō.

Summary

Meridian Energy Limited proposes to construct and operate an up to 420 MW alternating current (MWac) capacity solar farm on a 620 hectare site in the Western Bays above Lake Taupō, known as the Western Bays Solar Farm (Western Bays). Western Bays is anticipated to generate 870 GWh of electricity per year. This is 2.1% of New Zealand's current electricity generation.

Western Bays is one of the largest solar projects proposed in New Zealand. It is strategically located to capitalize on a large parcel of flat land close to core grid infrastructure, with high solar irradiance and minimal environmental impact.

Western Bays will result in the following significant national benefits:

- a substantial contribution to increasing renewable electricity generation to meet increased demand as New Zealand's need for energy grows and increasingly relies on electricity from renewable sources;
- through the Battery Energy Storage System (BESS) component, assisting to manage a developing capacity-induced security of supply risk identified by Transpower;

- bringing and maintaining forward and futures prices of electricity in line with the long run marginal cost of generation; and
- contribute to dealing with dry year risk.

Western Bays will also result in:

- a significant benefit to the regional and local economies during construction, including a peak of 280 direct full-time equivalent jobs during the approximately five year construction period;
- 6-20 direct full-time equivalent jobs during the lifetime of the solar farm, offset by a minor reduction in on-farm employment with the conversion of the land from dairy to sheep farming; and
- a minor reduction of nitrate emissions from the Western Bays site releasing constraints elsewhere in the Taupō catchment to which the cap and trade nitrate reduction scheme applies.

Increased demand for electricity in future

In 2020 Transpower produced a report looking at likely scenarios for the development of the New Zealand electricity industry to 2050. Its principal purpose was to help Transpower plan its network. After 2020 it regularly produced monitoring reports. The most recent was published in October 2024. It summarises demand forecasts to 2050 from various sources: Boston Consulting Group, Climate Change Commission, MBIE, and Transpower itself.[1] It also provides Transpower's estimates of the increase in GWs of capacity of renewables to meet the system needs in 2050 for each demand forecast.

The estimates vary but they all forecast the need for very large increases in renewable capacity, between 2.3 times and 3.1 times current levels.

The Infrastructure Commission has recently produced Forward Guidance Investment Forecasts for electricity and gas over the period 2025 to 2055. These forecast annual investment needs rising in 2025 prices from approximately $3.0 billion in 2025 to approximately $6.5 billion in 2035 and over $9.0 billion in 2055.[2] According to the Commission's estimates, approximately 90% of this investment will be required in electricity generation and associated network upgrades.[3]

The key drivers are renewals of the capacity of existing plant, demographic change and population growth, economic growth and, in the next twenty years, replacement of fossil-fuels as a source of energy across the economy.[4] Additional demand to support the expansion of data centres is also potentially important in the near term.

These data indicate there is a need for New Zealand to get on quickly with consenting new generation infrastructure. Western Bays will provide significant national benefits by meeting this need. More specifically, Western Bays is anticipated to generate 870 GWh of

[1] Transpower, Whakamana i Te Mauri Hiko: Monitoring Report, October 2024, p.4.

[2] See, for graph summary, New Zealand Infrastructure Commission, Shifting current: Energy infrastructure in transition, June 2026, Figure 39, p.65.

[3] Ibid., p.66.

[4] Op.cit., Figure 39, p.65.

electricity per year, or 2.1% of current generating output. It is one of the largest solar proposals in New Zealand to date, and it will make a substantial contribution to meeting the need for increased electricity generation.

Transpower, as System Operator, conducted its own review of the 2024 winter.[5] It noted the emergence of one security of supply risk that has been compounded by scarcity of gas. There is now an increased risk of insufficient capacity being offered in the market to meet energy and reserve needs in cold snaps, particularly in the shoulder months to winter of May and September. The risk is higher when the cold snap coincides with still conditions, so wind generation is also likely to be low.

With less gas available, parties naturally want to conserve their limited supply to deal with high peak prices in the main period of winter – June to August. The upshot appears to have been less highly flexible gas supply available and offered in the shoulder months of May and September. But in these periods, cold snaps can lead to high demand and if these coincide with still conditions, capacity issues can quickly arise.

Western Bays provides for the construction of four Battery Energy Storage Systems (BESS) at each of approximately 113 Power Conversion and Storage Blocks (PCSB) spread around the site. The output from the BESS is ideal for providing the flexible and quick responding support for the System Operator to avoid capacity-induced security of supply issues. The capacity of the Western Bays' BESS is planned to be a bit over 250 MW for 8 hours or 2,000 MWh. For context, the System Operator currently issues low residual situation Customer Advice Notices (CANs) when the national residual generation is less than 200 MW, thus the scale of the storage planned at Western Bays is material for managing this system risk.

An increased availability of flexible support from the BESS at Western Bays will provide significant national benefit. The System Operator has to ensure energy supply and demand are very closely balanced continuously even if lines or generators drop out unexpectedly due to weather, earthquakes, fires, equipment failure, etc.

If balance is not maintained, and supply is less than demand for more than a moment, very serious and extended outages can result, and have done so in overseas jurisdictions.[6]

If there are not sufficient flexible reserves, the System Operator has to initiate unplanned outages to be sure it can maintain the supply and demand balance. These are also disruptive to businesses and households and can impose a significant national cost, although less than if they are not corrected and a cascade failure of the system occurs.

Transpower sees the need for flexible support to maintain grid security against capacity constraints as likely to grow significantly as the demand for electricity increases and proportionately more of the available capacity is intermittent and less is flexible.

The New Zealand electricity market is a locational marginal price (LMP) market with co-optimisation of energy and reserves to choose the generation mix that meets demand at lowest overall cost, subject to transmission losses and constraints and reserve

[5] Transpower, Security of Supply Review – Winter 2024, November 2024.

[6] https://en.wikipedia.org/wiki/2025_Iberian_Peninsula_blackout.

requirements. Moreover, generators bear the costs of assets required to connect to the grid and the costs of upgrades to the interconnected grid are distributed on a beneficiaries-pays basis.

The corollary is that Meridian faces the economic consequences of the location of Western Bays relative to demand and transmission assets and the consequences of reserves needed to support its intermittent solar generation.

The output from Western Bays will be connected directly into the Bunnythorpe - Whakamaru A & B 220kV lines. These two parallel lines are major parts of Transpower's infrastructure to carry power from the South Island, where a lot of the country's generation is located, to the upper North Island, where a lot of the country's load is located.

Whakamaru, approximately 45 km north of Western Bays, is the southern terminal for Transpower's North Island Grid Upgrade Project. The project, which was completed in 2012, involved building a new "400kV line" from Whakamaru to a new substation at Brownhills with an underground extension of the grid to Transpower's existing Pakuranga substation. The purpose of the project was to provide extra capacity to cater for demand growth in Auckland and the need to get increased renewables to that market from further south.

The line was built so it can be converted to operate at 400kV, although it is only currently operated as a 220 kV line. The carrying capacity of a 400kV line is approximately 3.3 times that of a 220kV line.

Meridian is of the view that no upgrade of the interconnected grid will be required to cater for Western Bays' output. The strength of the grid in the area supports this view. However, if it is wrong in this, the financial costs of grid upgrades will fall on it to the extent it is the beneficiary. The issues of intermittent renewables "free-riding" on reserves and grid paid for by others that are raised overseas are not an issue in New Zealand; the market design avoids these.[7]

Dry-year risk

Hydro-electric generation has long been an important component of the New Zealand electricity supply. The generally steep topography and frequency of earthquakes result in it being expensive to build hydro storage dams with large capacity. Moreover, the level of precipitation and its timing can vary markedly from year to year. The upshot is that the New Zealand electricity system has for a very long time been vulnerable to running short of water to provide the "fuel" for hydro-power stations over winter, when demand is at a peak to meet higher household heating demand.

In the past, increased generation using fossil-fuels filled the gap when hydro storage fell short of requirements. Since the 1990s the principal fuel used for this has been natural gas. The cost of this generation was generally higher, and spot wholesale prices tended to be elevated in dry year winters. However, prices were not exceptionally high, as gas

[7] System Operator costs are to some degree socialised but the effect on efficiency of this is not material.

was readily available, and using coal at Huntly and, since 2004, diesel at Whirinaki to a limited degree, could supplement gas, if required.

Electricity markets

While it is common to refer to the electricity market, there is a suite of different but interconnected markets. Prices in the spot market can be very volatile. However, virtually all end consumers – households, commercial firms and industrials – do not directly pay these prices on a day-to-day basis. They usually pay a fixed price set by a retailer or, if they do buy from the spot market, have some form of hedge contract to fix their prices.

Hedge prices and long run marginal cost

Since the winter of 2019, the longer dated futures prices, which go out three to four years, have been persistently and significantly above estimates of the costs of new supply – what economists call the long run marginal cost (LRMC).[8]

[8] The data in this figure are now about two years old. For more recent data showing that long-dated futures, which go out 3-4 years, are still above LRMC see Figure 2 of Electricity Authority, *Hedge market summary February 2026*, published on 11 March 2026. Since March long dated futures prices have fallen further and the gap to estimated LRMC has closed further. The premium is in winter months when dry year risk is material. This recent Electricity Authority produced chart does not give the historical data, however. A similar chart provided in the Infrastructure Commission's June 2026 publication *Shifting currents: Energy infrastructure in transition* (Figure 27, p.47) also does not give historical data back to 1996. It also compares current futures with estimated long-run Levelised Costs of Electricity (LCOE) rather than LRMC, but the economic picture and conclusions are the same.

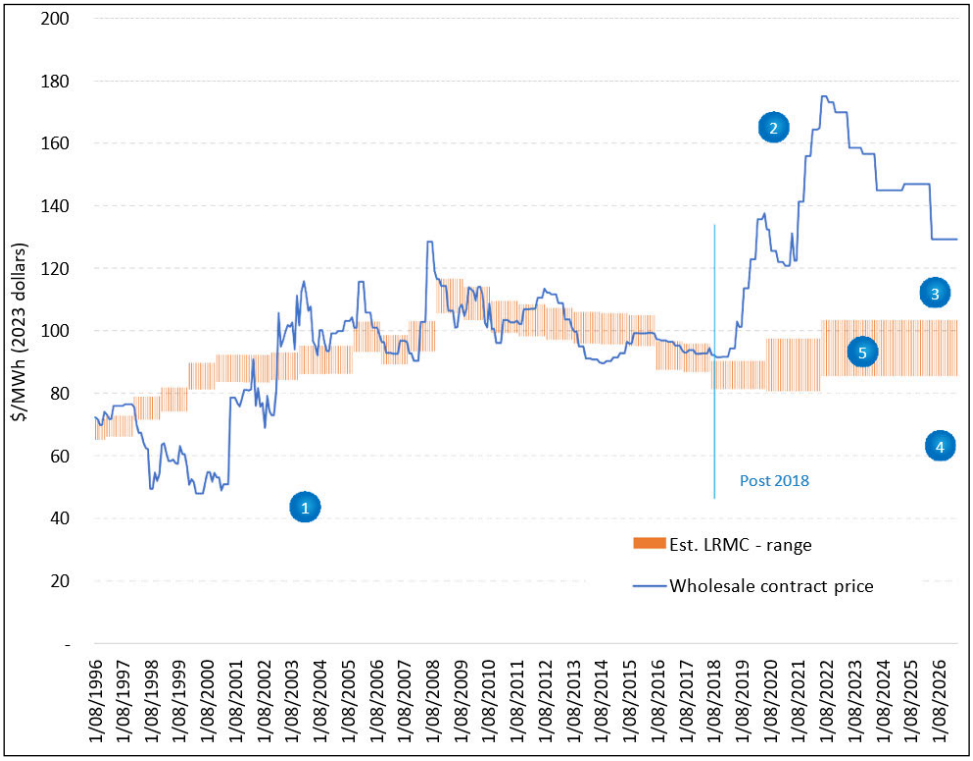


Figure 1: Contract (Futures) prices and estimated costs for new baseload supply
Source: Concept Consulting, Generation Investment Survey 2023 Update, Prepared for the Electricity Authority, 2024

If contract futures and forward prices are significantly above the costs of new supply the expectation is that new investment will occur, the increased supply will reduce futures and forward prices and the rough equivalence will be restored. Similarly, if contract prices are below the costs of new supply, some plants will not be replaced when retired, prices will rise and the rough equivalence will be restored.

Persistence of elevated contracted prices for future delivery has serious consequences for consumers. The prices in fixed price contracts and hedge contracts available to industrial and larger commercial firms will, when they come up for renewal, reflect the elevated forward prices. Similarly, retailers will see the high forward contract prices as either what they have to pay to serve households and small businesses, or the opportunity cost of serving households using their own generation.

Sustained elevated forward prices will also put upward pressure on the retail prices paid by households and small businesses and on how vigorous the competition for their business is among alternative retailers as the forward prices reflect either the actual or opportunity costs of satisfying customers.

The reason forward prices are elevated is dry year risk compounded in recent years by a shortage of fuel, and hence prices for back-up gas generation, and higher emission charges. The issue was clearly illustrated by the dry year 2024. The desire to conserve hydro led to generators raising their offer prices. Gas, and to some extent, coal at Huntly

and diesel at Whirinaki, came in to fill some of the gap but because of shortage in supply of gas this was not enough.[9]

Reductions in demand from the Tiwai smelter and some big wood processors, and diversion of gas from Methanex to generators, was needed. These additional sources reflected the value of lost load to these industrial parties, which is significantly higher than the cost of generation with back up gas, when relatively plentiful, or coal. From 2018 to 2023 average winter wholesale prices were around $180/MWh but in early August 2024 the average was over $800/MWh.

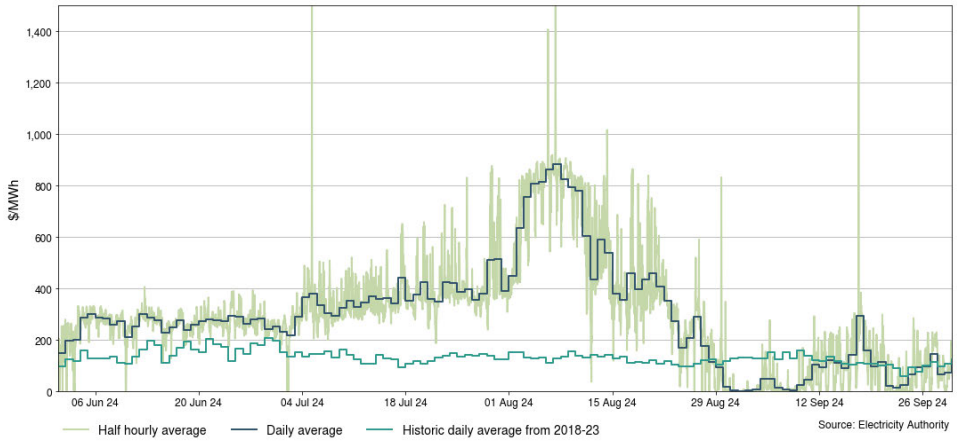


Figure 2: National average of wholesale prices from June-September 2024
Source: Electricity Authority

A number of factors contributed to the delay in the development of new generation in response to forward prices being well above LRMC for an extended period since 2019:

- The seriousness of the gas supply issue only became apparent gradually over 3–4 years after 2019, and more adverse information has been recently released when OMV announced decommissioning of Maui could occur by the end of 2026.
- There was uncertainty until 2024 as to whether Tiwai smelter, which currently uses, when not subject to demand restraint agreements, 11.4% of generation output,[10] would close.
- The Government's 5,000 GWh pumped hydro-scheme – the Lake Onslow Project - to deal with dry year risk overhang private investment decisions, at least until its likely $16 billion dollar cost and 15 years to build became public in late 2021.[11]
- The decision in 2018 to cancel granting new offshore oil and gas exploration permits may have negatively impacted investment in maintaining gas supplies from existing sources.

[9] See Electricity Authority, *Review of winter 2024*, April 2025, pp. 13-42 for a detailed description of offers during winter 2024 and how these changed over time.

[10] The smelter's current annual consumption of electricity is 5,000 – 5,200 GWh, when operating without demand restraint, the latest available annual electricity generation output, including heat and electricity plants in industrial use and small scale distributed generators, like roof-top solar panels, is 44,000 GWh. This figure relates to calendar year 2024. 5,000 GWh is 11.4% of 44,000 GWh.

[11] In late March, the Minister for Infrastructure approved an application from a private entity, Clutha Pumped Hydro Consortium, to have consenting of the Lake Onslow scheme considered under the Fast-track Approvals Act 2024. However, this does not negate the points made here about the impact of the Government promoting the scheme in the early 2020's on investment decisions by other parties at that time.

- Covid-19 and policy responses, including the spike in inflation created by some of these, disrupted normal supply lines and investment planning.
- The futures of Huntly's big units and the Taranaki Combined Cycle gas plant were uncertain. An agreement among the four major generator-retailers to support on-going availability of 3 Huntly Rankine units for 10 years was reached in August 2025 and authorised by the Commerce Commission in November. This has reduced uncertainty around Huntly.

The premium of contract prices for forward delivery above LRMC is likely to diminish and remain absent in future if significant new sources of generation are consented to parties that the market believes have the technical and financial resources to carry them through.

Meridian Energy's Western Bays project is a significant new source of generation, being expected to generate 870 GWh of electricity per year, which will have an impact on contract prices for forward delivery.

The impact on forward prices has been happening before the new generation is available, because the market assesses that a material level of the projects will proceed. Forward prices from when the market expects the new generation will come on stream has been reduced, other things equal.

The project will also provide a significant national benefit by contributing towards management of dry year risk in future years.

That a grid-scale solar power farm depends on sunlight and has lower output than average in winter, when hydro lakes are also low, does not undermine its contribution to reducing dry year risk. Water, and to some degree gas, not used because of the output of a solar power farm can generally be stored to be used later.

The development of a significant new fuel source for existing generators, such as development of an LNG importation terminal or making more water in hydro lakes accessible for generation, could also potentially reduce the premium of forward contract prices above LRMC.

Futures prices did ease after the Government's announcement in early February 2026 that it would proceed with an LNG import terminal proposal. However, the movement in prices was consistent across the range of futures contracts. Given the timeframe required to build an LNG terminal, this suggests that the easing is not likely to be attributable to the Government's LNG announcement. In this regard, it is noteworthy that in its commentary on hedge markets in February 2026 the Electricity Authority did not attribute the February price easing to the LNG terminal prospect. Instead, it stated "these decreases are potentially related to gentailer pipeline announcements from half-year reporting and recent sustained low wholesale prices."[12]

The Government has estimated that "LNG availability is expected to lower forward electricity prices by at least $10/MWh, regardless of whether LNG is used in any

[12] Electricity Authority, *Hedge market summary February 2026*, p.2.

particular year or not"[13] It bases this on an estimated short-run cost of $200 - $250 per MWh for electricity generated using imported LNG in existing gas-fired generators.[14] Either this impact had already been factored into futures prices before the announcement or market participants are sceptical it will occur in the three-year time frame listed futures are traded for.

Electricity generated from Western Bays will have total or long run marginal cost well below the estimated $200 - $250 per MWh short run cost of electricity produced using imported LNG so the building of an LNG facility would not crowd it out of the market or negate the benefits of Western Bays.

The $200 - $250 per MWh estimate was based on international LNG prices for forward delivery late last year. These were significantly below current prices for LNG because of the expectation additional capacity will come on stream in the next few years. The recent conflict in the Gulf has led to prices for spot and near term delivery rising appreciably and greater uncertainty about supply increases and falls in prices in future. If the short-run imported LNG estimates were to be recalculated by MBIE today, I have no doubt they would be above the $200 - $250 per MWh range.

The anticipated generation capacity of Meridian Energy's Western Bays proposal (870 GWh of electricity per year) is 2.1% of New Zealand's current generation. It is a significant infrastructure project with national benefit from helping to bring and maintain contract forward prices back into line with the costs of additional energy supply.

Local and Regional Economic Benefits of Western Bays

Meridian estimates the capital investment to construct the project will be around $0.8 billion. Annual operational costs are estimated to be $13.5 million in current prices for the 35 plus year lifetime of the project.

The project will provide substantial employment opportunities during the construction phase with an estimated 60 to a peak of 280 direct full-time equivalent jobs during the approximately five year construction period. This will be a significant regional benefit.

It is estimated that 6 - 20 direct full-time equivalent jobs will be required in the local area to maintain and operate the plant for the 35 plus years lifetime of the project. The land under the solar panels will shift from being used for dairying to sheep farming. There is likely to be some small reduction in employment in farming locally as a result of this. Overall, the very local employment effects once the plant is operating are likely to be minor.

The shift from dairy to sheep farming will reduce the nitrate load generated from the land under the solar farm. The Lake Taupō basin is subject to a cap and trade emissions scheme to reduce nitrate run-off into the lake and maintain its water quality. The scheme was introduced in 2007. The reduction in nitrate run-off the change in land use under

[13] *Fact sheet: LNG*, Released with Government announcements on LNG terminal. See https://www.beehive.govt.nz/sites/default/files/2026-02/2026%20Fact%20sheet%20-%20LNG%20Procurement.pdf

[14] *Loc. Cit.*

Western Bays will allow the transfer of emission "credits" to other areas in the lake's basin to increase farm production elsewhere.[15]

Thomas Brent Layton

16 June 2026

[15] See https://www.protectinglaketaupo.nz/about/the-project/