Report

Demand Response Study

Potential benefits of demand response at a proposed 300MW eSAF facility at Marsden Point

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EXECUTIVE SUMMARY

Fortescue is currently in the pre-feasibility phase of a green hydrogen manufacturing facility at Marsden Point to produce synthetic sustainable aviation fuel (**eSAF**).

The eSAF project provides an opportunity to assist in the decarbonisation of the aviation industry by producing locally made renewable fuel. The aviation sector is broadly viewed as a hard-to-abate sector. It is also broadly viewed that eSAF can provide a solution to this problem, particularly for long haul flights where other emission reduction technologies may not be suitable.

The eSAF project proposed at Marsden Point could supply approximately 60 million litres of eSAF per year – equivalent to more than 3 per cent of the pre-Covid annual jet fuel requirements for the aviation sector in New Zealand. This would assist in the decarbonisation of the aviation industry by displacing approximately 180,000 tonnes of carbon dioxide equivalent (0.18 **$MtCO_2$-e**) emissions per year. Additional impacts would include the emissions reductions attributable to less production and shipping of jet fuel from overseas destinations.

The Energy Efficiency and Conservation Authority (**EECA**) has supported this study under its mandate to encourage, promote and support energy efficiency, energy conservation and use of renewable energy. This report brings together work completed by Fortescue and its subcontractors which addresses the opportunities for demand management to be included in the eSAF concept to improve project feasibility while improving the efficiency, security and supply of the entire New Zealand grid.

The planned facility uses renewable electricity to generate green hydrogen via electrolysis. The green hydrogen is then combined with biogenic carbon dioxide in the eSAF portion of the plant to make the eSAF product. The electrolysers can be quickly turned down and then up again to reduce the electricity demand on the grid. Hence by adding hydrogen storage to the plant, the plant can be built with a capability to reduce power demand (**Demand Response**). However, the eSAF plant cannot change the throughput quickly and must have a constant hydrogen input rate.

The duration the electrolysis can be turned down is a function of how much hydrogen storage is installed. However, larger durations have other impacts such as a greater capacity of electrolysers are required to be installed to then catchup/refill the hydrogen storage, which will then increase the plant maximum load on the grid. Secondary issues like grid capacity constraints then also need to be understood.

A four-hour Demand Response capability will cost tens of millions of dollars for the additional hydrogen generation capacity and hydrogen storage required.

The direct benefit to the project of Demand Response is that at times of peak power costs the power purchased from the grid can be reduced, and then the hydrogen production made up at times of lower power cost. This needs to be evaluated against the significant additional cost and other operational issues of the Demand Response capability.

Fortescue engaged engineering consultancy firm, Jacobs, to complete a study to assess the potential impact on private and public stakeholders and on the New Zealand electricity market of having the ability to reduce power demand by utilising hydrogen storage at Fortescue's proposed Marsden Point eSAF plant in the Upper North Island of New Zealand. 5 case/sizes of hydrogen storage from 0 to 5 hours were tested in the analysis.

The study demonstrated that implementing hydrogen storage to enable demand response could have significant benefits both to Fortescue as well as the greater NZ market and economy.

The study presents the outcomes related to the impact of the hydrogen storage, and the associated ability to reduce electrical load, on the load-weighted wholesale prices paid by New Zealand electricity consumers and the overall impact to the general resilience of the grid. The study demonstrated that there are significant (up to almost NZD 800 million per annum in 2045) savings expected to accrue to electricity consumers because of the plant's ability to reduce power demand (via hydrogen storage) during periods of peak market prices – particularly after 2035 when the remaining thermal baseload plant has retired.

Additionally, the plant's Demand Response capability can have advantages in managing risk associated with electricity market volatility, and overall to consumers in New Zealand by deferring and/or reducing the cost of transmission investment that would be required if a new load the size of the eSAF plant proposed were to connect in Northland provided it was set up to respond to market triggers. It was found that even one hour of hydrogen storage largely eliminated the impact of the transmission constraint in 2030, and substantially reduces it in 2035, which would suggest a transmission deferral benefit of up to NZD 100 million, depending on the preferred transmission enhancement option.

Further analysis by Jacobs was completed on regulatory constraints for demand-side flexibility services in the New Zealand Electricity Market. Demand-side management has become a focus area, with recent market design changes and consultation papers highlighting the need for efficient price signalling and demand-side participation. While there is consensus on the benefits of demand-side management, barriers to entry remain, including historical fixed-price tariffs, stable electricity prices, and high costs of interacting with the market. Recent reports have identified key barriers and proposed measures to address them, including standardised flexibility contracts and an ahead market. The Electricity Authority has prioritised some of these measures, but implementation timelines are uncertain, and resourcing may be a bottleneck. It is recognised there is greater ability for a large, sophisticated participant in the energy market to overcome some of these barriers.

Work by engineers and consultants supporting the project has helped to identify additional constraints and impacts of installing Demand Response capability as part of the development. This will require further analysis to fully evaluate the impacts.

One other area that has been identified by this work is the potential to turn the entire plant down for extended durations as part of a longer/larger Demand Response. The potential value and impacts of this will require further study.

Importantly, the project has not identified any technical constraints that would restrict its ability to incorporate Demand Response capability. The Project will incorporate the ability to reduce power demand into the plant design, enabling some of the benefits outlined in this report.

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1 INTRODUCTION

Fortescue is currently in the pre-feasibility phase of studying the development of an eSAF plant at Marsden Point in the Upper North Island of New Zealand.

As part of this work, the project is investigating the impact on private and public stakeholders and on the New Zealand electricity market of having the ability to reduce power demand by utilising green hydrogen storage at Fortescue's proposed Marsden Point. This report outlines the results of the investigation.

Figure 1 Project Location

1.1 Project Background

The aviation sector is broadly viewed as a hard-to-abate sector. It is also broadly viewed that eSAF can provide a solution to this problem, particularly for long haul flights where other emission reduction technologies may not be suitable.

As an alternative to fossil fuel-based aviation fuel, eSAF can be produced using feedstocks of green hydrogen and carbon dioxide. If these feedstocks are taken from sustainable and biogenic sources, this offers significant decarbonisation potential for the aviation industry.

The eSAF project proposed at Marsden Point could supply c.60 million litres of eSAF per year – equivalent to more than 3 per cent of the pre-Covid annual jet fuel requirements for the aviation sector in New Zealand. This would assist in the decarbonisation of the aviation industry by displacing approximately 0.18 MtCO2-e emissions per year.

Fortescue has identified the Marsden Point site as an ideal location for an eSAF facility due to New Zealand's excellent renewable energy potential, the site having existing permits and approvals for this type of industry, access to the jet fuel supply chain to the Auckland airport and a locally available source of biogenic CO2.

The pre-feasibility study (**PFS**) includes analysis of the project's benefits to New Zealand, including the potential provision of large-scale demand response, enabling power demand to be reduced when needed.

1.2 Demand Response Market Modelling

Fortescue commissioned market modelling to investigate the commercial and market impact of the demand response capability. The model used baseline assumptions drawn from a combination of publicly available sources[1] and augmented with local and current industry knowledge of the consultant.

The modelling team used PSR's[2] suite of generation expansion and hydro-thermal optimisation models (OptGen and SDDP), which are highly regarded internationally for optimisation in hydro-thermal systems like New Zealand's.

1.3 Project Report

This report covers the following deliverables as part of a Project Funding Agreement with EECA:

a. the outputs from the demand response modelling;

b. the quantified benefits of the demand response capability, and how these benefits can be shared for the benefit of NZ consumers;

c. the key barriers and/or enablers that need addressing for the identified demand response benefits to be delivered to NZ consumers;

d. the decarbonisation benefits of the eSAF production for the NZ aviation sector; and

e. insights into the viability of an eSAF facility at Marsden Point, where reasonable given the highly commercially sensitive nature of establishing a new industry/market.

[1] Ministry of Business, Innovation and Employment, Business Energy Council, Transpower, Interim Climate Change Commission, National Renewbale Energy Laboratory
[2] PSR is a global provider of consulting services, computational modelling and energy innovation. [Software « PSR (psr-inc.com)]

2 DEMAND RESPONSE MODELLING OF THE E-SAF FACILITY

The project is currently in the PFS phase, with design and project development occurring on many fronts. At the commencement of PFS, multiple studies were commissioned with specialist consultants and contractors simultaneously due to the very wide range of issues and scopes to be addressed.

This section provides an outline of the overall facility, the Demand Response modelling that Jacobs were commissioned to undertake and the assumptions used for the modelling.

2.1 Plant Design

The proposed production facility would use electrolysers to produce 35,000 tonnes per year of green hydrogen and utilise a Fisher-Tropsch process to produce eSAF. For the purposes of this study, the eSAF facility consists of 3 main components:

- **Hydrogen production system** (electrolysers) that are the most significant load in the facility. These can be turned up and down quickly with associated change in hydrogen production rates.
- **Hydrogen storage facilities**. These can be used to store hydrogen to make up hydrogen production if the electrolysers are producing at lower rates than the eSAF plant requires as feedstock. Note that to charge the hydrogen storage, additional hydrogen production capacity (i.e., more electrolysers) are required with associated CAPEX cost for additional electrolysers and storage facilities. Due to the cost of facilities, and difficulty in storing hydrogen, only a few hours of hydrogen storage is feasible.
- **The e-SAF synthesis production facility**. This is a chemical synthesis plant that requires a constant feed of hydrogen. This plant can be turned up and down, but this takes days to implement with production risk, so would only be done occasionally (i.e., once or twice a year) and for longer durations (i.e., weeks).

The project will require approximately 300 MW of power. New renewable electricity generation projects would be developed with a range of partners to provide the power required.

The motivation for hydrogen storage at the plant is to allow the electrical load to flex (turn down) in response to market signals and other operational factors. The Demand Response capability would be determined by how much the electrolysis could be turned down. Other plant loads are not expected to be able to be turned down in short timeframes.

The duration the electrolysis can be turned down is a function of how much hydrogen storage is installed. However, larger Demand Response durations have other impacts such as the requirement to install a greater capacity of electrolysers to then catchup/refill the hydrogen storage, which will then increase the plant maximum load on the grid. Secondary issues like grid capacity constraints then also need to be understood.

The direct benefit to the project of Demand Response is that at times of peak power costs, the amount of power purchased from the grid can be reduced via lower hydrogen production, and then subsequently make up the hydrogen production at times of lower power prices. This needs to be further evaluated against the significant additional cost, which must be countered against the benefits of the Demand Response capability.

2.2 Demand Response Modelling and Assumptions

For the purposes of this report, hydrogen storage is referred to in terms of hours of full electrolyser production where one hour of hydrogen storage is equivalent to approximately four tonnes of hydrogen at the proposed electrolyser size, e.g., "four hours" of hydrogen storage indicates the capability to store 16 tonnes of green hydrogen at the facility.

Market modelling was undertaken using five potential levels of hydrogen storage capacity - from no storage to 4 hours of hydrogen storage – and across four "snapshot" years – 2030, 2035, 2040, and 2045. This approach enabled exploration of a wide variety of scenarios across time while remaining computationally and analytically efficient.

A secondary purpose of this study is to explore the implications of storage and the associated ability to turn power demand down on the performance of a power purchase agreement (**PPA**). For the purposes of this study, it is assumed Fortescue will be pursuing PPAs with generation developers to introduce new renewable generation into the market and help manage spot market risk.

The starting point for this analysis was Jacobs' New Zealand electricity market (**NZEM**) base case. The base case is developed using publicly available data and models the NZEM up to a nodal, hourly resolution over decades to capture the development of load and supply throughout the energy transition and beyond. Fortescue's proposed eSAF plant was added to the base case load development and the generation expansion was adjusted to reach a new supply-demand equilibrium.

2.3 Baseline energy scenario assumptions

Jacobs' base case scenario uses assumptions based on publicly available data which is then augmented with Jacobs' market expertise and experience. A summary of assumptions is outlined in the table below.

Table 1 Jacobs' base case scenario assumptions

Assumption	Parameter	NZEM assumptions
Policy	NZ ETS	Remains in-place throughout the forecast horizon
	100% renewable by 2030	Not enforced
Demand	Demand growth	Jacobs Base, adapted from BusinessNZ Energy Council (**BEC**) 2060 Kea scenario
	Electric vehicle (**EV**) growth	Jacobs Base, adapted from Waka Kotahi/NZ Transport Authority base case 2022 and calibrated against BEC2060 analysis
	Process heat electrification load	Jacobs Base, adapted from BEC 2060 analysis
	Rooftop PV and residential storage	Jacobs Base, adapted from BEC 2060 analysis and Whakamana I te Mauri Hiko
Project timings	Transmission upgrades	Net Zero Grid Pathways (**NZGP**) stage 1: 2024-2026 NZGP stage 2: 2031 High voltage direct current fourth cable: 2030
	NZ Battery	None

	New Zealand's Aluminium Smelter exit	Remains throughout modelling horizon
	Coal prices	Beginning at elevated Indonesian benchmark coal price (Genesis Energy published) decaying to long-run average by 2025-26
	Carbon prices	Jacobs's base, adjusted from BEC2060 Kea scenario and Interim Climate Commission modelling

The long-term national energy demand is consistent with the BEC 2060 Kea scenario with exception that the Tiwai Point aluminium smelter remains in service throughout the modelling horizon. Other adjustments have been made to reflect:

- the modest observed growth since the BEC 2060 reference year (2018) relative to the BEC 2060 modelled demand, and
- updated EV fleet figures.

The resulting annual energy demand forecast is presented in the graph below.

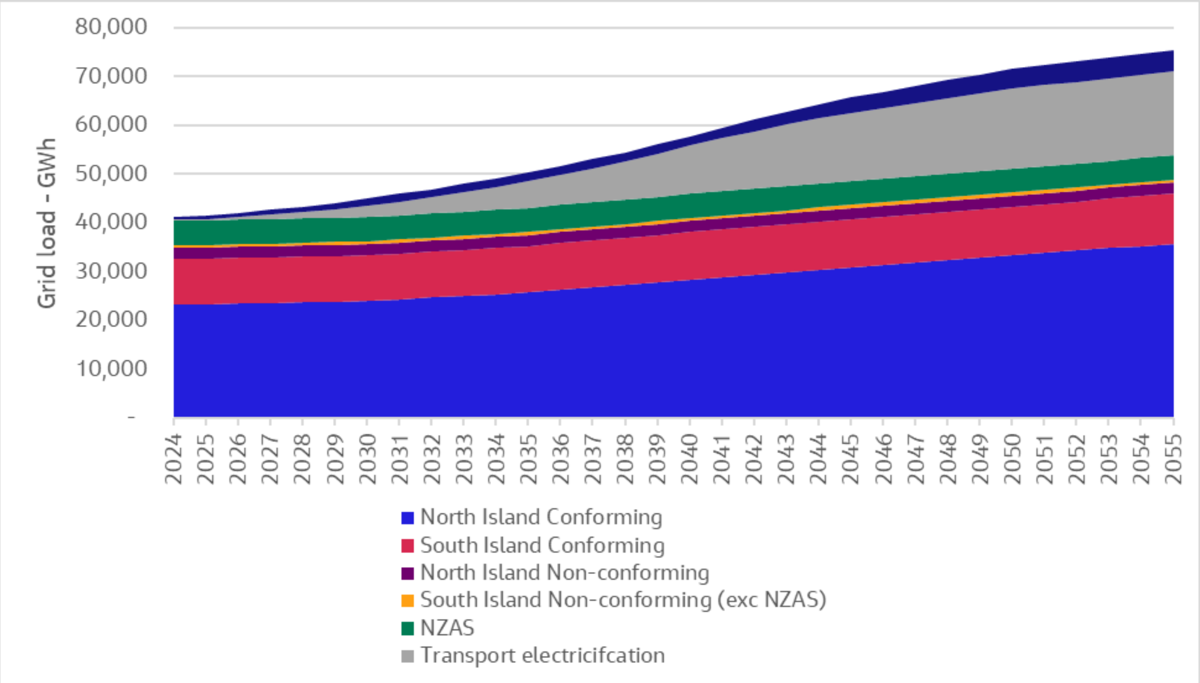


Figure 2 Annual Energy Demand Projection

The modelling enforces retirement of existing thermal plant as defined in the table below.

Table 2 Thermal retirements

Project Name	Technology	Fuel	Transmission Mode	Island	MW	Retirement year
Te Rapa	Cogeneration	Gas	WRK220	North Island	44	2024
Taranaki Combined Cycle	Combined-cycle gas turbine (**CCGT**)	Gas	SFD220	North Island	385	2025
Whirinaki	Open-cycle gas turbine (**OCGT**)	Diesel	WHI220	North Island	155	2029
Huntly Unit 3	Rankine Cycle	Coal/Gas	HLY220	North Island	250	2030
Huntly Unit 4	Rankine Cycle	Coal/Gas	HLY220	North Island	250	2030
McKee	OCGT	Gas	MCK110	North Island	102	2033
Huntly e3p	CCGT	Gas	HLY220	North Island	400	2035
Huntly p40	OCGT	Gas	HLY220	North Island	48	2035
Stratford Peaker	OCGT	Gas	SFD220	North Island	200	2035
Marsden Point Diesel	OCGT	Diesel	MDN220	North Island	102	2035

2.4 Modelling Methodology

All modelling was undertaken using OptGen and SDDP from PSR's suite of hydro-thermal system optimisation models. **OptGen** is a system expansion optimisation model that builds a least-system cost generation expansion plan incorporating hydro-logical uncertainty. **SDDP** is a hydro-thermal dispatch optimisation model that considers the opportunity cost of releasing water from reservoirs.

OptGen and SDDP are integrated to perform an iterative search that utilises the dispatch optimisation outcomes from SDDP in each subsequent iteration of OptGen to improve the estimate of operating cost in the expansion planning optimisation.

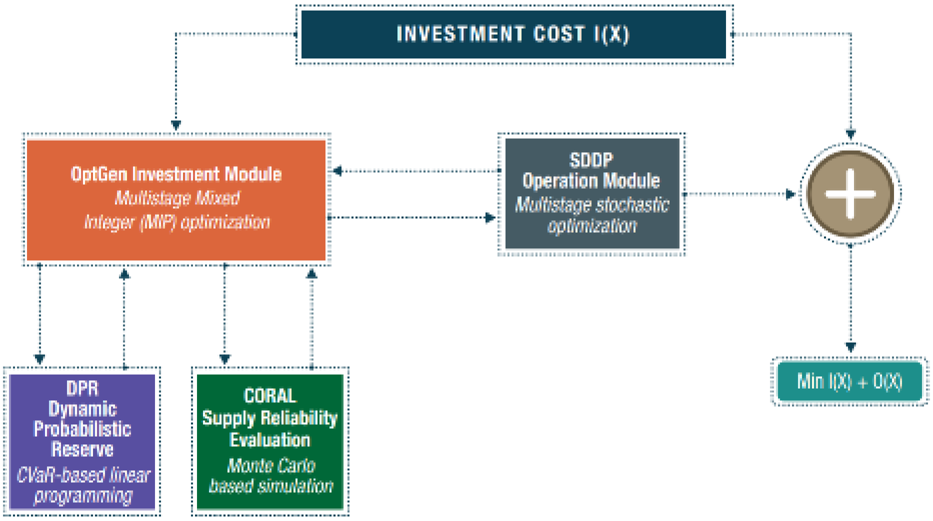


Figure 3 OptGen-SDDP procedure

OptGen decomposes the planning problem into two components: investment and operation. The Investment Module uses capital and fixed operation cost data along with generalised constraints to reflect policies and guidelines (e.g., emissions reductions targets, firm energy, or capacity targets) and uses an estimate of operating costs provided by the Operation Module. This integration with SDDP ensures that the expansion plans must consider the same uncertainties that are visible to the dispatch model.

The SDDP algorithm was developed to assess optimal water dispatch policies ("future cost functions") in electricity markets with large amounts of hydro-electric supply. The future cost function provides an expected "cost-to-go" between some point in time and the end of the study horizon as function of storage levels. The cost-to-go is then used in the market simulation as part of the objective function expanded (relative to the typical market least cost simulation) to include minimising the sum of the immediate costs (e.g., fuel, deficit, carbon) and future costs (i.e., the value returned by the future cost function given the final storage after the decision is made).

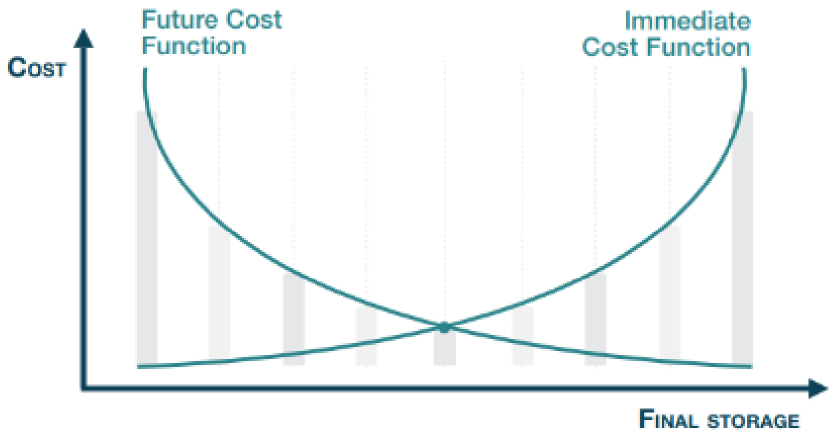


Figure 4 Future cost and immediate cost schematic

The modelling used water-value functions with a weekly time-step – effectively updating the water policy for each week in the modelling horizon – and hourly resolution in the final simulations across 89 historical hydro sequences.

Renewable resource generation traces were produced using PSR's time-series lab (**TSL**), which draws historical wind and solar data from the ERA5 and MERRA2 databases and produces solar and wind generation sequences based on the latitude and longitude of the farms included in the input data and farm specification such as turbine power curves and turbine hub height.

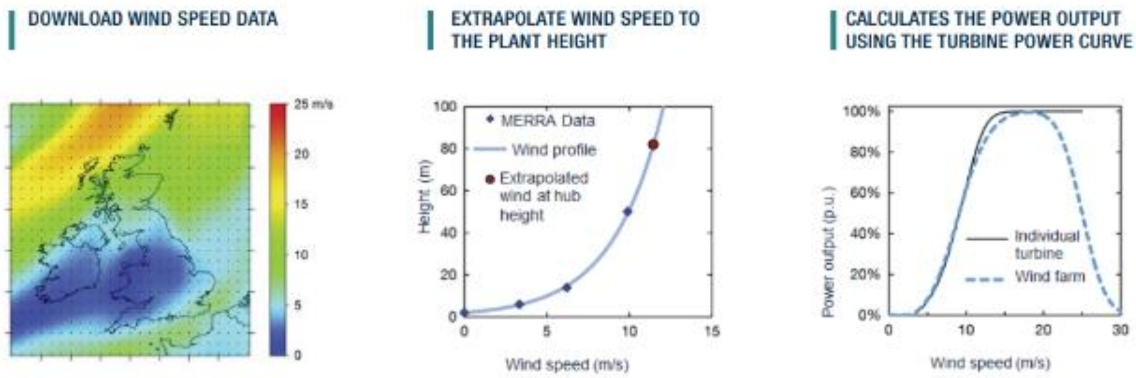


Figure 5 Time-Series Lab trace production

A core part of TSL's process is to analyse the relationship between solar, wind, and hydro energy inflow sequences. This process allows it to produce synthetic scenarios that are appropriately correlated across space and time, and across solar, wind and hydro plants. This is particularly important as the historical wind and solar dataset (~40 years) is significantly smaller than the hydro dataset (~90 years) and the correlation between the production of renewable technologies has a material impact on future capacity requirements.

3 TRANSMISSION IMPLICATIONS

There is potentially very significant transmission investment deferral benefit to all Northland consumers from having at least one hour of hydrogen available at the proposed facility from commissioning.

The site of the proposed eSAF plant is in a part of the transmission network with little existing local supply, relatively low load, and limited import capacity relative to the size of the proposed load. The addition of the eSAF plant would approximately double Transpower's “prudent” forecast of local demand in 2038.

If transfer capacity were not increased, either through additional transmission enhancement or operational measures such as a special protection scheme to operate the circuit above their N-1 ratings, the results of the modelling show that:

- The transmission constraint – when combined with the additional load from the eSAF plant – leads to a large price separation between Northland and the rest of the country, despite the additional solar, wind, and geothermal capacity that is brought online in the area. This would result in Northland consumers paying significantly more for electricity than consumers in the rest of the country.
- Hydrogen storage defers and reduces the magnitude of the price separation. For example, just one hour of hydrogen storage results in Northland prices in 2030 that are comparable to the rest of the country and the same could be said of four hours of hydrogen storage in 2035.

More transmission capacity is likely to be required at some point if the proposed eSAF plant is commissioned in Northland even if four hours of hydrogen storage is available.

Fortescue has commissioned Jacobs to undertake a separate grid constraints study that will provide option analysis for transmission investment. The additional capacity could be an enhancement to the Huapai to Bream Bay circuit to increase N-1 capacity or some sort of special protection scheme (**SPS**) that allows the circuits into Northland to be operated at greater than their N-1 capacity. Dispatchable demand facilitated by hydrogen storage could play a role in such an SPS.

By way of example - a reasonable first estimate of the cost of reconductoring the 120 km Huapai to Bream Bay circuit, that is the primary driver of the constraint, at NZD 3 million per kilometre would be NZD 360 million[3]. Deferring that NZD 360 million investment from 2030 to 2035 – which the modelling outcomes indicate would be possible with a moderate amount of hydrogen storage – at Transpower’s standard discount rate of 7 percent, would save NZD 103 million.

The transmission pricing methodology (**TPM**) would allocate the cost of additional interconnection investment according to the share of the benefit received by each customer. Therefore, any transmission customer that would be expected to benefit from the upgrade would be allocated some of the cost of the investment. Beneficiaries would likely be load customers in Northland and generation customers in the rest of the country. By corollary,

[3] Transpower, given their greater knowledge of asset capability, might be able to increase capacity at a lower cost by identifying specific assets that constrain flows and/or operational schemes that greater transmission while maintaining N-1 security.

any customers who are expected to pay for the transmission upgrade would be also expected to benefit from deferring or reducing the magnitude of the investment required. For as long as interconnection upgrades could be deferred, other transmission customers would likely see a reduction in transmission charges as the same transmission costs are spread across more load.

While the TPM would allocate a significant portion of the upgrade cost to Fortescue due to the size of the load, more than half of the cost would likely be allocated to generation customers and other load customers. The reduction and/or deferral of this additional cost could, therefore, be considered a public benefit of Fortescue's investment in hydrogen storage. We emphasise that this is the benefit of the eSAF plant with hydrogen storage relative to the eSAF plant without hydrogen storage; the net effect on interconnection charges of the eSAF plant on other Northland load customers would likely be a reduction in charges related to the existing interconnection assets that would probably be outweighed by the cost of new transmission investment when it is required.

The remainder of our analysis assumes that the transfer capacity into Northland is increased so that the rest of the investigation is not confounded by a highly constrained network. This decision reflects the fact that operating the plant would be exceedingly difficult unless there is a material increase in import capacity into the region and/or very significant local supply build including dispatchable supply.

This assumption might not reflect the transmission solution that Transpower would ultimately build if the plant were built, but it is a reasonable simplifying assumption for this analysis:

1. The resources required to undertake a comprehensive transmission options analysis are very significant and a lot of the data required sits with Transpower.

2. Such a large increase in energy load for the region (the eSAF facility would likely double the Northland load) is likely to lend itself to an increase in the physical transmission capacity rather than a more tactical solution than an SPS, which is more suited to situations where likelihood of transfer being over the N-1 limit is relatively low.

3. If Transpower is increasing physical capacity, the economics of transmission build often lend themselves to providing capacity for an upside case as the cost of higher capacity is often relatively small in the context of the project, depending on the particular options in play.

4 WHOLESALE MARKET IMPLICATIONS

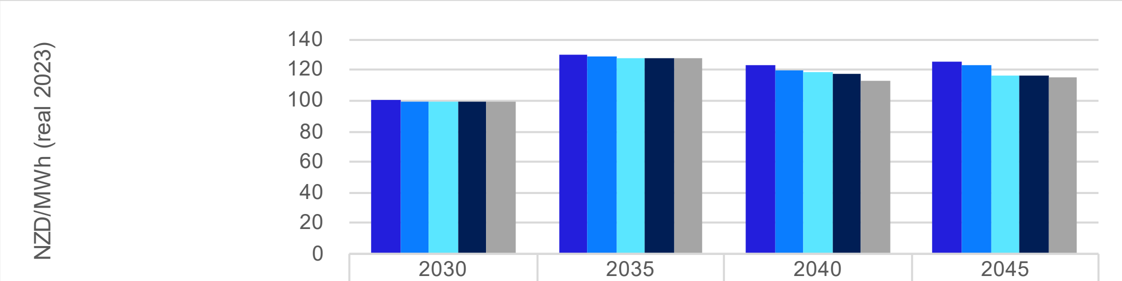
Once the transfer capacity is resolved, the wholesale market benefit of the storage (load reduction) is relatively muted at the beginning of the study horizon but increases as greater penetration of variable renewable energy (**VRE**) enters the market and the opportunities for intra-day arbitrage increase. By 2045, the expected decrease in load-weighted average spot price is NZD 10 per megawatt-hour (**MWh**), representing a saving of almost NZD 800 million per annum in 2045 (real 2023 terms) to New Zealand consumers.

4.1 Power Purchase Agreement Interaction

PPA interaction has been considered from two perspectives:

- **“Power Cost Minimisation**” where the electrolyser load is flexed (turned down) using the available hydrogen storage in response to spot price, which could be considered a risk neutral strategy. The implication of this approach is that any surplus generation from the PPA is sold on the spot market. This is our default modelling approach, which results in the outcomes presented below.
- “**Self Consume”** where Fortescue operates the electrolyser and storage to maximise own use of generation associated with the PPA each hour. This would be considered a more risk averse strategy than the Power Cost Minimisation strategy. The Self Consume strategy can result in high electrolyser load during times of high spot prices if generation from the PPA is sufficient to supply the electrolyser load.

The figure below presents the annual load-weighted average spot price (**LWAP**) across the whole market for each storage level and snapshot year modelled assuming the Power Cost Minimisation strategy.

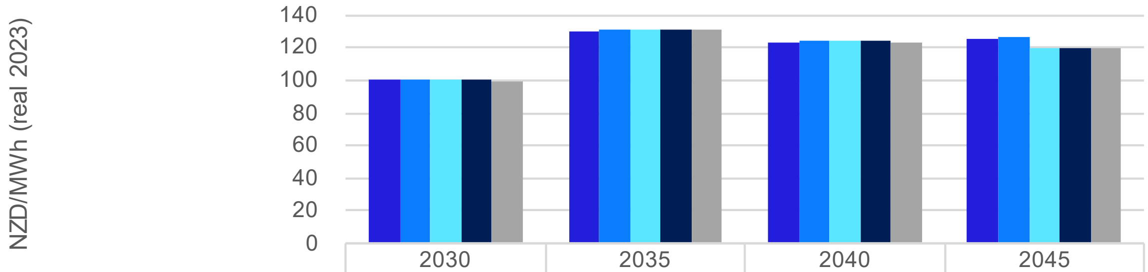


	2030	2035	2040	2045
LWAP - no H2 storage	101	130	123	126
LWAP - one hour H2 storage	100	129	121	123
LWAP - two hours H2 storage	100	128	119	117
LWAP - three hours H2 storage	100	128	117	116
LWAP - four hours H2 storage	99	128	113	116

Figure 6 Load-Weighted Average Spot Price – Power Cost Minimisation Strategy

The Self Consume PPA strategy reduces the wholesale price benefit of hydrogen storage but also significantly reduces Fortescue’s spot price exposure. Hydrogen storage reduces spot exposure in general as it tends to reduce prices and move load to periods of lower prices which often coincide with periods of high VRE production. However, when storage is combined with the Self Consume strategy, spot price exposure is reduced further still, but the downward pressure on spot prices is reduced greatly relative to the Power Cost Minimisation strategy.

The figure below presents the annual LWAP for each storage level and snapshot year modelled assuming Self Consume strategy.



	2030	2035	2040	2045
LWAP - no H2 storage	101	130	123	126
LWAP - one hour H2 storage	100	132	124	126
LWAP - two hours H2 storage	100	131	124	120
LWAP - three hours H2 storage	100	131	124	120
LWAP - four hours H2 storage	99	131	124	120

Figure 7: Load-Weighted Average Spot Price – Self Consume Strategy

4.2 Electrolyser Net Energy Cost

The strike price for the modelled PPA is not known, so we have undertaken a sensitivity analysis on a range of solar and wind prices based on the two PPA modelling approaches.

The outcomes show a clear benefit (on average) of the Power Cost Minimisation PPA strategy where energy from the PPA is traded on the spot market rather than aggressively prioritised for own use.

Table 3: Percentage Reduction in Net Energy Costs to Fortescue from Power Cost Minimisation PPA strategy in 2045 with 4 hours of hydrogen storage

		Solar Strike Price – NZD/MWh (real 2023)								
		80	**85**	**90**	**95**	**100**	**105**	**110**	**115**	**120**
Wind Strike Price – NZD/MWh (real 2023)	**80**	9%	9%	8%	8%	7%	7%	6%	6%	6%
	85	9%	9%	8%	7%	7%	7%	6%	6%	6%
	90	9%	8%	8%	7%	7%	7%	6%	6%	6%
	95	9%	8%	8%	7%	7%	6%	6%	6%	6%
	100	9%	8%	8%	7%	7%	6%	6%	6%	5%
	105	9%	8%	8%	7%	7%	6%	6%	6%	5%
	110	9%	8%	8%	7%	7%	6%	6%	6%	5%
	115	9%	8%	7%	7%	7%	6%	6%	6%	5%
	120	8%	8%	7%	7%	6%	6%	6%	6%	5%

Table Note: Energy costs to Fortescue from Power Cost Minimisation PPA strategy in 2045 with 4 hours of hydrogen storage.

However, the Self Consume PPA strategy substantially reduces the worst-case spot exposure cost on a weekly basis, as shown in the two box-and-whisker charts below. The figure below shows the distribution of weekly spot cost exposure (when electrolyser load exceeds PPA generation and energy must be purchased on the spot market) with a Power Cost Minimisation approach to managing the PPA, i.e., letting spot price determine electrolyser load rather than generation from the PPA.

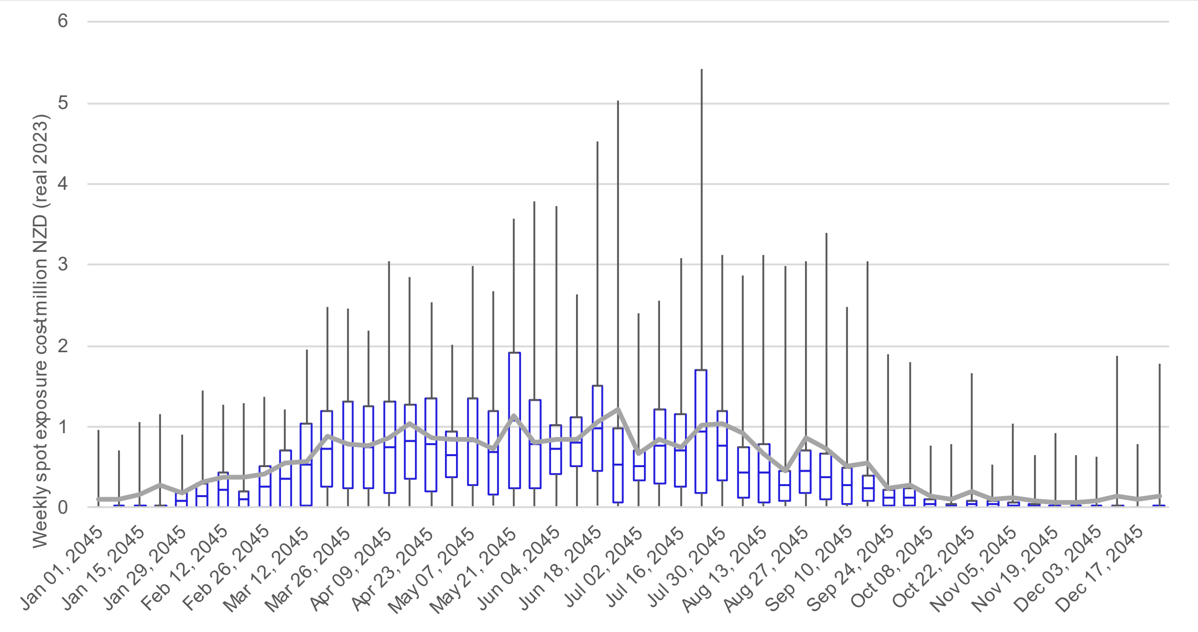


Figure 8: Spot exposure cost distribution in 2045 with four hours hydrogen storage and Self Consume PPA Strategy

Figure Note: Costs indicated are with four hours hydrogen storage and Power Cost Minimisation PPA strategy.

The below figure shows the same data but in the case with the Self Consume strategy i.e., the electrolyser load is operated to use as much PPA generation as possible even if spot prices are high. Note the lower peaks in spot price exposure cost and lower mean, which drops from NZD 29 million to NZD 19 million across the year. This lower worst-case exposure would need to be traded off against the higher expected net energy costs associated with the risk averse approach shown in Table 3 above.

The two approaches demonstrate ends of the spectrum, the likely operating strategy will be a combination of the two considering real time inputs.

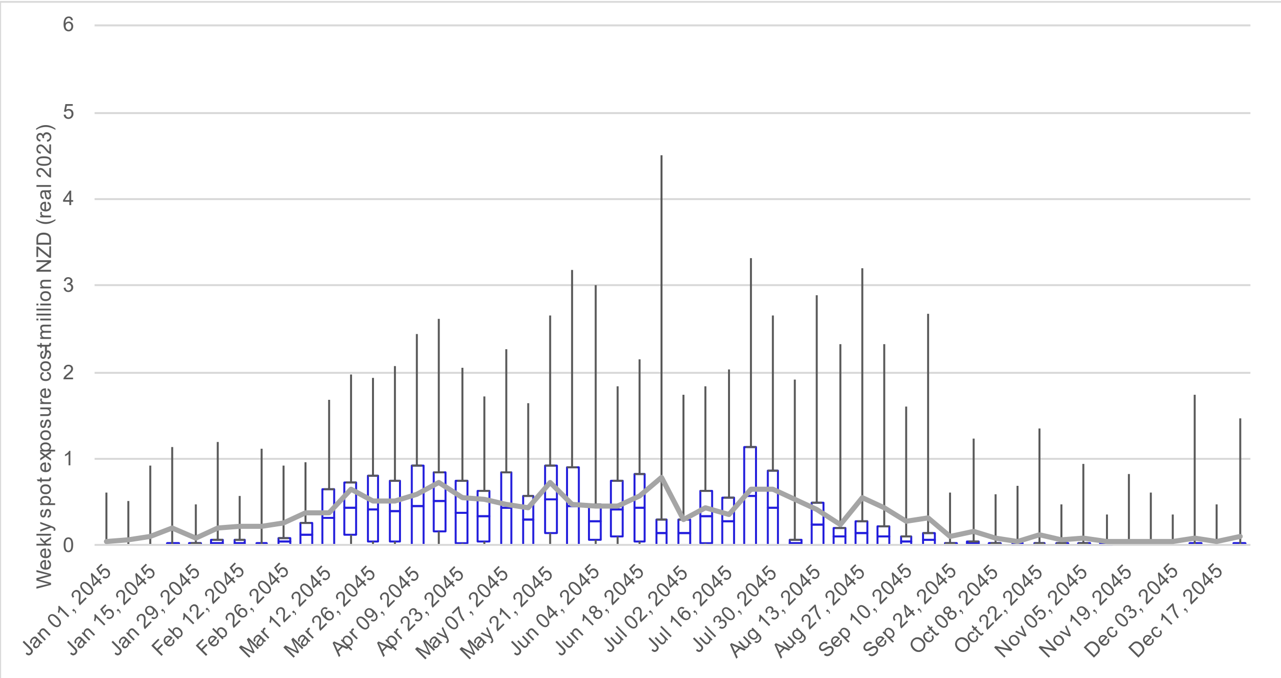


Figure 9 Spot exposure cost distribution in 2045 with four hours hydrogen storage and Self Consume PPA Strategy

4.3 Summary

Pulling the elements together, there is a significant benefit to Fortescue in having hydrogen storage at the proposed eSAF plant at Marsden Point. Hydrogen storage reduces net energy costs by allowing hydrogen to be produced at times of lower spot prices then reducing hydrogen production (and hence energy demand) at times of higher power prices by using hydrogen from storage rather than making hydrogen with the electrolyser. This impact is modest at the beginning of our studies in 2030 but increases to up to an NZD 42 million reduction in power costs per year by 2045.

In addition to expected energy cost reduction, hydrogen storage reduces spot exposure risk in both the Power Cost Minimisation and the Self Consume operating modes.

Operation of the PPA depends to some degree on the risk appetite; the Power Cost Minimisation approach yields the lowest expected net energy cost but leaves the eSAF plant exposed to greater spot risk than the Self Consume strategy. The actual strategy will balance risk and be dependent on commercial consideration from both energy markets and product sales.

Similarly, the benefit to other New Zealand consumers is somewhat dependent on the operational policy of the electrolyser and storage relative to the PPA. There are significant consumer savings (up to almost NZD 800 million per annum in 2045 with 4 hours of hydrogen storage) if that operational policy is to minimise power costs.

Having demand response via hydrogen storage would defer and/or reduce the cost of transmission investment that would be required if a new load the size of the eSAF plant proposed were to connect in Northland, assuming it is set up to respond to address the transmission grid constraints. Even one hour of storage largely eliminates the impact of the transmission constraint in 2030, and substantially reduces it in 2035, which would suggest a transmission deferral benefit of up to NZD 100 million, depending on the preferred transmission enhancement option.

There may be a case for starting with a small storage volume and increasing over time. Other than deferring the transmission investment, the market benefit of storage in 2030, and to a lesser degree 2035, is relatively muted. This suggests the case in these earlier periods is primarily transmission investment deferral, rather than system-wide energy arbitrage. However, by 2040 and 2045 when significantly more intermittent energy generation is expected to be installed in the system, the energy market benefits become more substantial – assuming the Power Cost Minimisation strategy is followed – suggesting that more storage capacity would likely be justified.

5 BENEFITS OF THE DEMAND RESPONSE CAPABILITY

This section presents the outcomes related to the impact of hydrogen storage on the load-weighted wholesale prices paid by New Zealand electricity consumers and the overall impact to the general resilience of the grid.

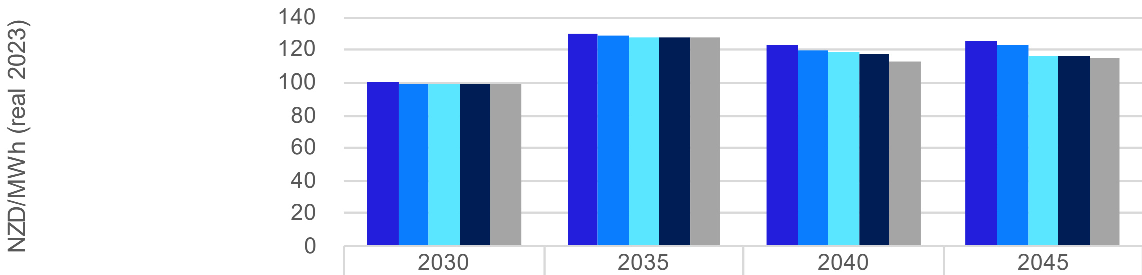
5.1 Spot Prices

Once transmission constraints are resolved, the impact of hydrogen storage on the spot price is primarily in the form of energy arbitrage – moving electrical load from time periods when supply is tight (e.g., a winter cold, still winter evening) to time periods when supply is plentiful (e.g., during the middle of the day when the sun is shining and heating loads are generally lower). Notably, the magnitude of the hydrogen storage investigated is one to four hours of eSAF production, so it is insufficient to provide material seasonal or even weekly firming, although it can provide significant daily arbitrage and/or firming.

Shifting load to periods of more plentiful supply results in less dispatchable demand being turned off and less expensive peaking generation being dispatched, tending to result in lower spot prices.

The impact of hydrogen storage on annual load-weighted average electricity prices is muted at the beginning of the study horizon but becomes large by the end of the study horizon. In 2030, the penetration of wind and solar is still relatively small, so the intra-day swings in prices are relatively small. Most of the price volatility during this period is of a similar nature to what we see in the NZEM today; relatively sustained high prices during dry periods that are too long for a few hours of storage to materially impact.

The figure below shows the impact of hydrogen storage on national LWAP, ranging from only a few dollars in 2030 to NZD 10 per MWh in 2045 as the opportunities for intra-day arbitrage increase as more intermittent renewables enter the market (as shown in figure 10 below).



	2030	2035	2040	2045
LWAP - no H2 storage	101	130	123	126
LWAP - one hour H2 storage	100	129	121	123
LWAP - two hours H2 storage	100	128	119	117
LWAP - three hours H2 storage	100	128	117	116
LWAP - four hours H2 storage	99	128	113	116

LWAP - no H2 storage LWAP - one hour H2 storage LWAP - two hours H2 storage
LWAP - three hours H2 storage LWAP - four hours H2 storage

Figure 10: National Load-Weighted Average Price

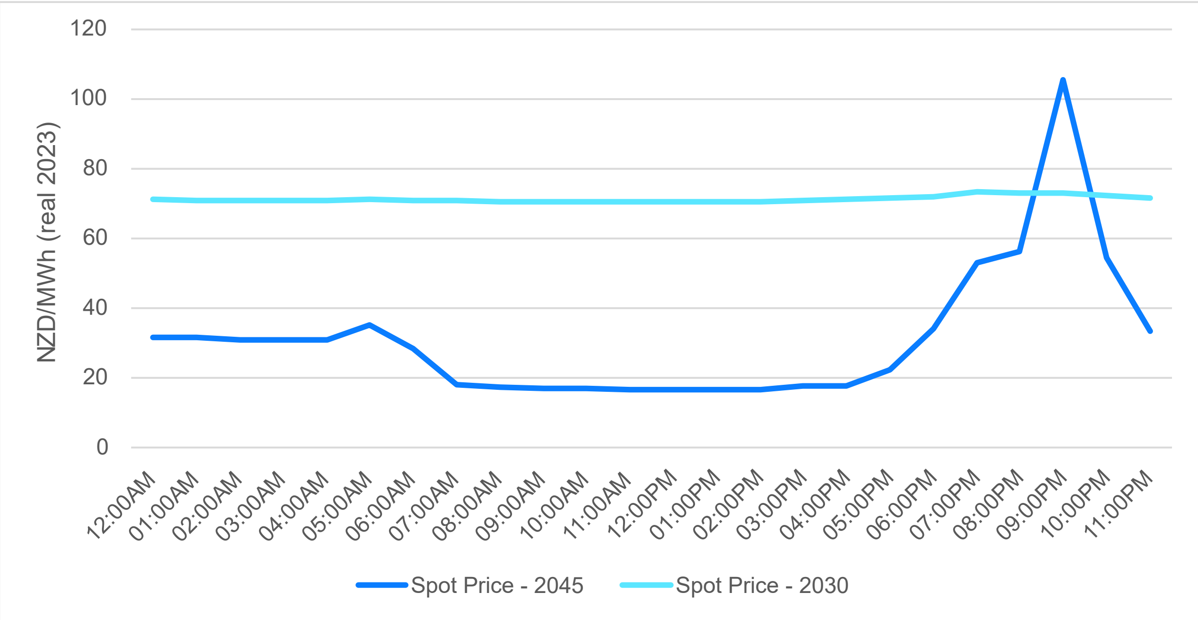


Figure 11: Mean January Hourly Spot Price (2030 vs 2045)

5.2 System Operating Cost Savings

Demand-side flexibility, such as that provided by the hydrogen storage at Fortescue's proposed eSAF plant, reduces the expected system cost, e.g. the cost of fuel and carbon. These costs are distinct from the consumer energy cost savings presented in the next section as they focus on the input cost rather than the consumer cost, which is driven by the marginal cost of energy in each trading period. As such, system costs are generally considered a more robust marker for changes in system surplus for the purposes of public interest cost-benefit analyses.

The system costs considered in this section are fuel cost savings, carbon cost savings, and the benefit of avoided load reduction. The cost of “elastic” load has been developed internally within the Jacobs team based on several tranches of load that is expected to respond to high market prices. Given that the elastic load cost does not necessarily represent a change to economic surplus with a one-to-one relationship to the elastic load price, we present sensitivities with and without elastic load included.

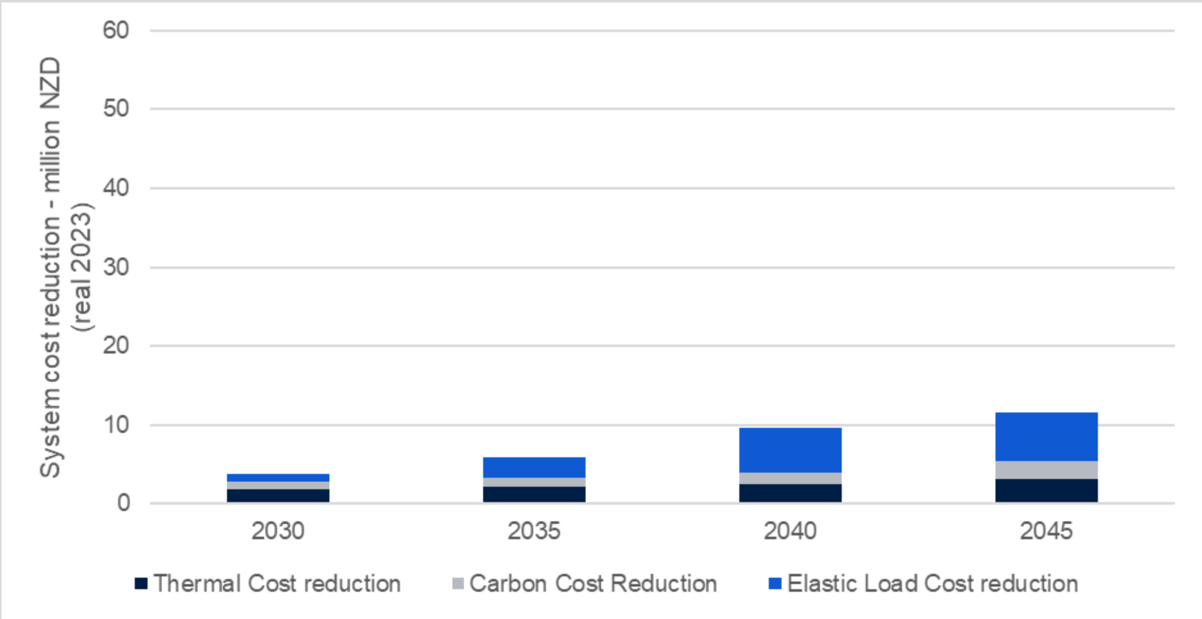


Figure 12: System Cost Reduction – one hour hydrogen storage

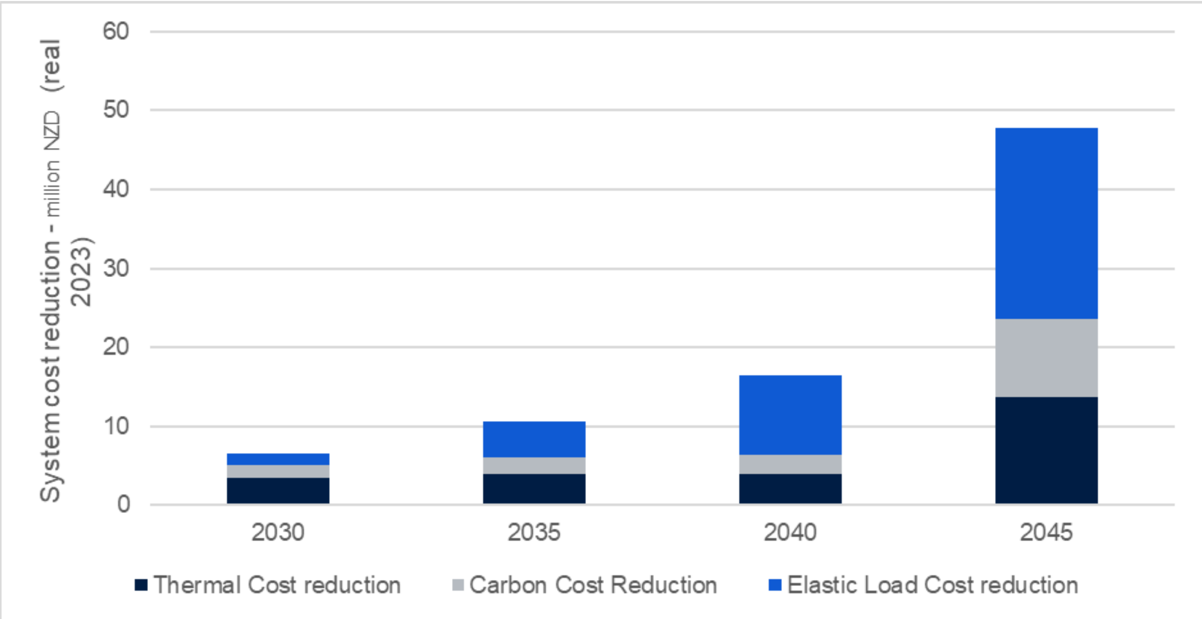


Figure 13: System Cost Reduction – two hours hydrogen storage

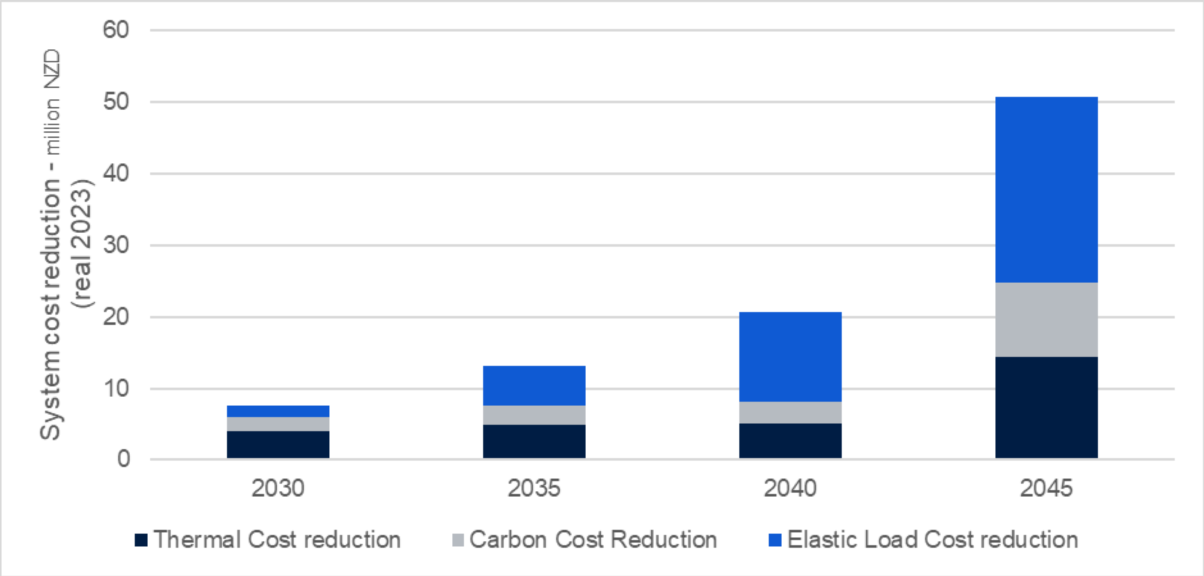


Figure 14: System Cost Reduction – three hours hydrogen storage

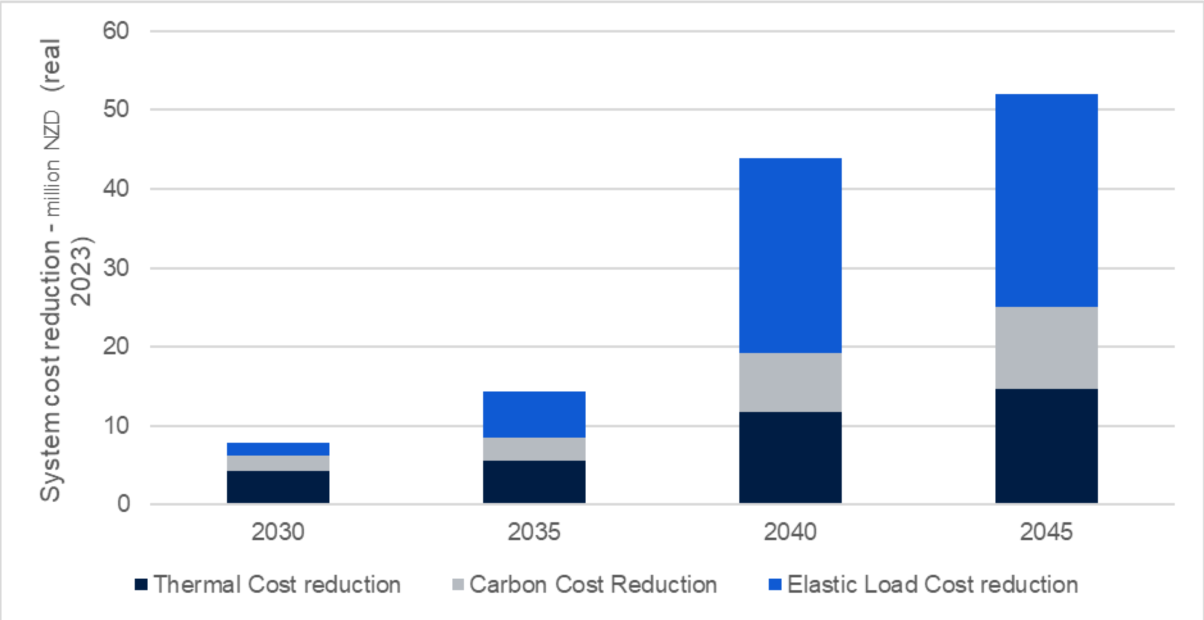


Figure 15: System Cost Reduction – four hours hydrogen storage

As discussed earlier, market modelling was undertaken on four snapshot years (2030, 2035, 2040, and 2045), so a continuous cashflow of system cost benefits is not available. However, if we were to assume that linear interpolation between approximation between these snapshots is a reasonable approximation of the missing years, the present value benefits will be given by the table below. Note that the system benefits have been assumed to start in 2030 and have been discounted at 7% to a present value in 2024.

Table 4: Estimated Present Value System Benefit

Hydrogen storage	Excluding elastic load benefit	Including elastic load benefit
One hour	NZD22.37M	NZD43.61M
Two hours	NZD49.76M	NZD96.54M
Three hours	NZD58.72M	NZD113.26M

Four hours	NZD79.13M	NZD154.54M

5.3 Consumer Energy Cost Savings

The decrease in wholesale prices can reasonably be expected to result in lower prices to electricity consumers over time. While only a small number of large consumers are directly exposed to the wholesale market, retail prices are generally supported by hedge contracts that are renegotiated every few years and will be informed by expected wholesale prices. Therefore, lower wholesale prices can be expected to result in lower retail prices.

The figure below shows the expected annual energy savings to electricity consumers for each modelled hydrogen storage capacity relative to the cost in the case without hydrogen storage.

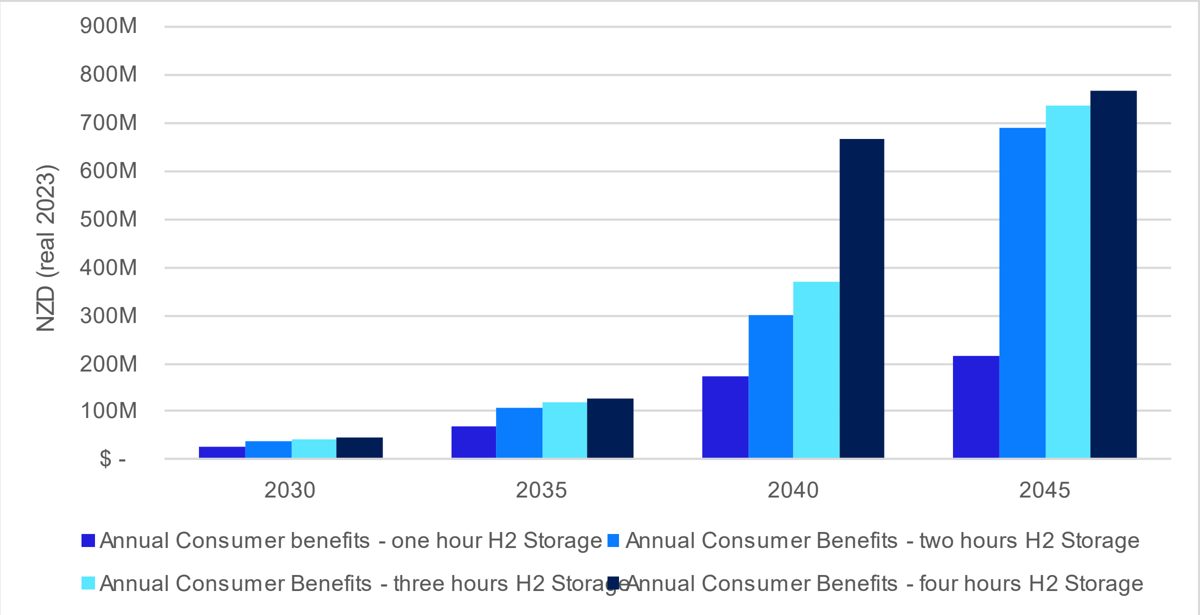


Figure 16: Expected Annual Consumer Electricity Savings

The outcomes above suggest that there are significant (up to almost NZD 800 million in 2045) savings expected to accrue to electricity purchasers, including consumers and retailers, because of the plants ability to reduce power demand (via hydrogen storage) during peak market prices – particularly after 2035 when the remaining thermal baseload plant have retired.

5.4 Upper North Island Resilience

This section will discuss the results of the fourth study exploring the impact of hydrogen storage on resilience to a significant and extended dispatchable generation outage. The study is a variation of the second study PPA with risk averse PPA management. This study reduces the thermal peaking capacity of the system by 200 MW for three weeks in mid-winter to consider a case when thermal peaking capacity is most essential to the system. The horizon starts on 25 June and ends on 16 July of each five-year interval.

The table below shows the average weekly percentage impact on the spot price during the outage under different hydrogen storage assumptions in the studies where the PPA management is risk averse (i.e., where electrolyser load follows PPA generation).

Table 5: Reduction of Spot Price (Self Consume PPA Strategy)

Year	Week	Comparison (% difference versus no storage case)			
		One hour	Two hours	Three hours	Four hours
2030	**25th June**	-5%	-5%	-2%	-4%
	2nd July	-2%	-3%	-1%	-2%
	9th July	-1%	-1%	-1%	-1%
2035	**25th June**	-4%	-4%	-2%	-3%
	2nd July	-2%	-2%	-1%	-1%
	9th July	-1%	-2%	-1%	-1%
2040	**25th June**	-4%	-4%	-2%	-4%
	2nd July	-1%	-2%	-1%	-1%
	9th July	-2%	-3%	-1%	-2%
2045	**25th June**	-5%	-6%	-4%	-20%
	2nd July	-2%	-3%	-2%	-11%
	9th July	-1%	-1%	-1%	-9%

The figure below shows the weekly average price of the original study (second study) compared to the resilience study (fourth study) for each year and storage capacity.

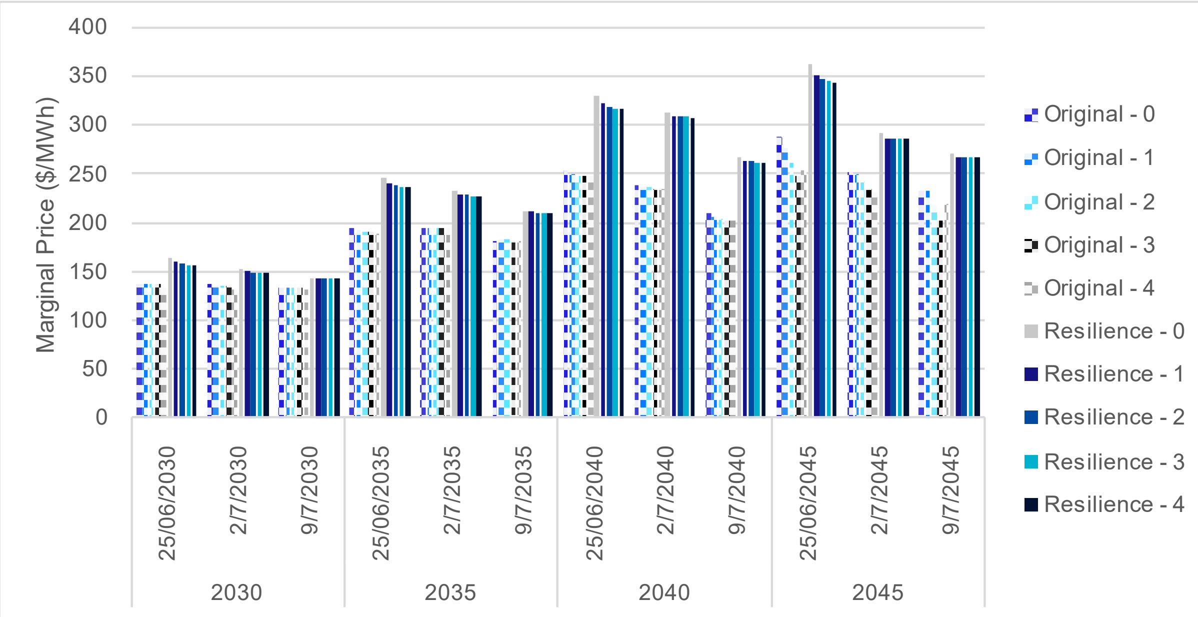


Figure 17: Spot Prices – Base vs Resilience Cases (Self Consume PPA Strategy)

Note the minimal impact on prices of additional storage when the operational policy of the plant is to follow PPA generation. This effect is similar to that observed in the base case and is generally the result of the same behaviour; electrolyser load remaining high at times of high prices as long as PPA generation is high.

Following a less PPA-focused, risk neutral approach to electrolyser loading results in a greater reduction in spot price as hydrogen storage in increased as shown in the table below, which showcases the percentage decrease in marginal price between the no storage and the other storage cases during the simulated unplanned outage event.

Table 6: Reduction of Spot Price (Power Cost Minimisation PPA Strategy)

Year	Week	Comparison (% difference versus no storage case)			
		One hour	Two hours	Three hours	Four hours
2030	25th June	-3%	-6%	-7%	-8%
	2nd July	-2%	-3%	-5%	-5%
	9th July	-1%	-2%	-2%	-3%
2035	25th June	-3%	-5%	-7%	-8%
	2nd July	-2%	-5%	-7%	-8%
	9th July	-2%	-4%	-5%	-6%
2040	25th June	-4%	-7%	-10%	-12%
	2nd July	-4%	-6%	-10%	-12%
	9th July	-4%	-6%	-8%	-9%
2045	25th June	-5%	-7%	-9%	-10%
	2nd July	-4%	-6%	-7%	-8%
	9th July	-2%	-4%	-5%	-5%

Note the general increase in spot price reduction as hydrogen storage is increased.

The figure below shows the average weekly marginal prices for both Power Cost Minimisation studies during the unplanned outage period.

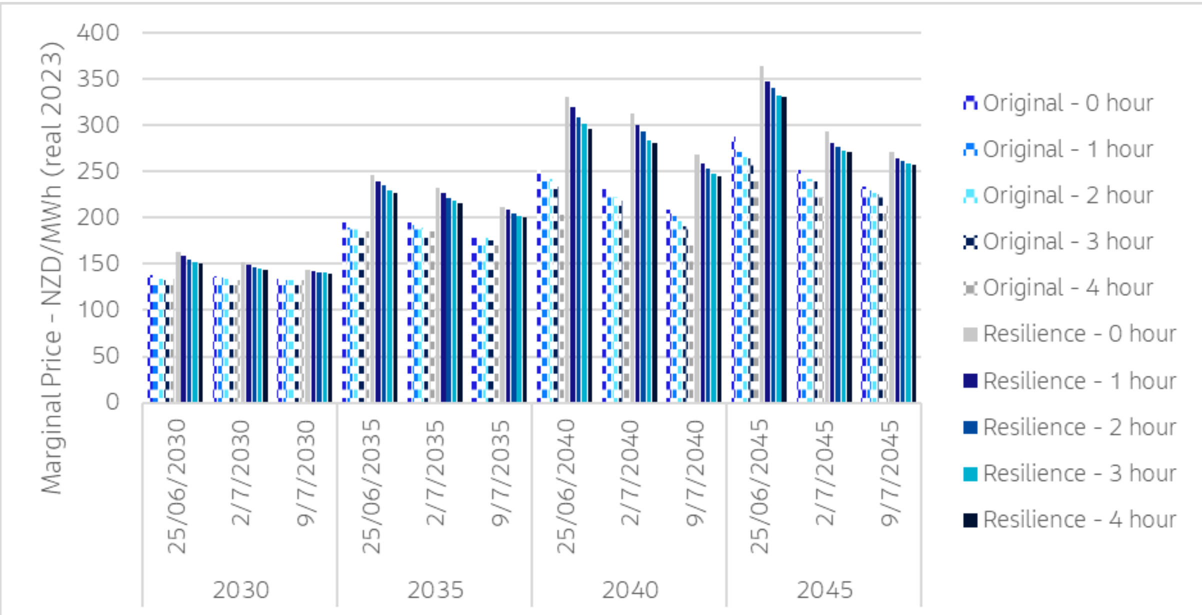


Figure 18: Spot Prices – Base vs Resilience Cases (Power Cost Minimisation Strategy)

6 GREATER PLANT CONSIDERATIONS

As stated previously, the project is in an early stage, with design and project development occurring on many fronts. When the current phase of the project (PFS) was commenced, multiple studies were commissioned with specialist consultants and contractors simultaneously due to the very wide range of issues and scope to be addressed.

To enable the Jacobs Demand Response modelling to commence, initial assumptions needed to be made about various plant components with regard to the overall plant's Demand Response capabilities. In parallel to this, other areas of design were undertaken to identify constraints and capabilities.

These studies, and how they relate to the plant's Demand Response capabilities are detailed below.

6.1 eSAF Plant Performance and Flexibility

The eSAF plant is a very complicated process utilising Fischer-Tropsch technology to convert the feed gases (hydrogen and carbon dioxide) into the appropriate hydrocarbon chains for jet fuel. This involves many process steps, and reactions across catalysts and fractionation/distillation columns where the pressure, temperature, chemical mixtures and velocities are all critical to ensure proper and complete reactions.

At the commencement of the PFS a specialist eSAF licensor technology provider was engaged to develop the design of the eSAF process portion of the plant. As part of their scope, they were to develop details of the operational flexibility of the plant, including:

1. Ability and speed for the plant to turn up and down as well as turndown limits
2. Impacts on product and utilities from turning up and down
3. Potential modifications to improve plant flexibility/operability
4. Expected shutdown frequency for the plant – both planned and unplanned
5. Identify the electrical loads associated with the eSAF plant, and how the loads change with plant turndown, as these need to be added to the electrolyser and other plant loads to determine the maximum demand on the grid.

From the licensor's work, the following was determined:

1. The plant operates best in steady-state. Adjustment of the throughput is possible, but this should be done in a controlled manner and may take days to adjust to the new throughput and achieve stable production. Off-spec product can be expected during the transition that would be required to be dealt with.
2. The plant has the ability to operate in the ranges of 100% to 60%.
3. The eSAF unit will require in the order of 40 MW to operate. This load will reduce with turndown and is not linear with plant throughput.

This work provides the required inputs for a larger Demand Response opportunity where the entire plant be operated at a lower rate for extended periods, for example “dry year” Demand Response.

6.2 Electrolyser Technology Selection

The main component in the hydrogen production, and a key decision for the project, will be the electrolysers to be employed. It is noted that the “hydrogen revolution” is in its very early stages, with rapid technology development, changes and learnings in the electrolyser space. Very few electrolysis hydrogen production systems of the scale of the one planned for Marsden Point exist in the world, and hence there is very little data to be drawn on.

Four main technologies are being considered for the development:

1. High Pressure Proton Exchange Membrane
2. Low Pressure Proton Exchange Membrane
3. High Pressure Alkaline water electrolysis
4. Low Pressure Alkaline water electrolysis

The selection of the electrolyser technology will be determined later in the project, but understanding the suitability, performance, technical maturity and commercial implications for the options is critical in understanding impacts it may have later in the project evolution.

The main engineering contractor has undertaken an electrolyser technology selection study for the project. The key conclusions from the study relevant to this report are:

1. PEM technologies have the ability to turn down to as low as 10%, and to rapidly turn up and down (turndown from 100% to 10% in a few minutes)
2. AWE technologies have less turndown capability (to around 50%) and slower turnup and turndown speeds (i.e. tens of minutes)

The report also indicates that the degradation and lifespan of the electrolysers is impacted by the speed, frequency and depth of turnup and turndown.

From this work it has been concluded that for Demand Response, as a starting point it should be assumed that the electrolysers can only be turned down to 50% and this turndown would occur over a half hour period. Once the actual electrolysers have been selected, and suitable actual performance data has been obtained, the ability to flex the electrolysers (both depth and speed of turndown) could be looked to be increased.

6.3 Electrolyser System Sizing

For a Demand Response system based on turning the electrolysers down and pulling from hydrogen storage, once a Demand Response event has occurred, the hydrogen storage would be required to be refilled to enable the plant to be able to respond to further Demand Response events.

Given the need to supply a constant feed rate of hydrogen to the eSAF plant, this would require over-sizing of the hydrogen production capacity to be sufficient to supply the eSAF plant whilst also building the inventory of hydrogen back into storage.

The sizing of the storage and the additional hydrogen make-up are interrelated. For example, a 1-hour Demand Response capability would require a different hydrogen storge and make-up capacity compared to a 2-hour capability. But the design is also a function of how much the electrolysers are assumed to be turned down (e.g. if the electrolysers are assumed to turn down 10% rather than 50%, this requires a different storage requirement).

Additionally, the system design needs to consider how long the Demand Response system is required for, and hence the duration that the storge can be replenished over.

This all impacts not only the installed capacity of electrolysers, but also the peak load and size of required grid connection when the hydrogen storage is being recharged.

There are other issues that also required study. For example, while the individual electrolysers come as quite small units (1-10 MW stacks), they are usually set up as “trains” of multiple units (e.g. 50MW trains) with associated balance of plant supporting each train.

Electrolysers degrade over production life, increasing the energy required per unit of hydrogen production. As electricity cost is such a significant part of production costs, economic operation prompts electrolyser replacement during operating life, which is normally undertaken in a staggered fashion. However this means that a “250 MW” electrolyser system may not be suitable for the required production – so a 270 MW system may be required to be installed to allow for degradation.

This all impacts the design of the overall production system, and optimum electrolyser installed capacity sizing to ensure the required installed electrolyser capacity over production life.

Given the capability and requirements of the Demand Response system are still under review, the main engineering contractor was required to study many alternatives and identify impacts and issues, and the optimum system sizing.

6.4 Hydrogen Storage and Costs

One key element of the Demand Response system will be the ability to store hydrogen in the required volumes to enable continuity of hydrogen supply when the electrolysers are turned down.

Hydrogen, being such a small light molecule, is very difficult and energy intensive to compress and store. The main engineering contractor has undertaken a hydrogen compression and storage study to review the alternative options for hydrogen storage. This study includes scalability, technical maturity, weight and space requirements, safety aspects and cost.

Storage options have been considered in conjunction with the different electrolyser technologies noted above, to ensure the complete hydrogen system is understood. For example, the high pressure electrolyser options require less hydrogen compression for storage, but the storage pressure needs to be considered with the hydrogen production pressure.

The hydrogen storage study has now provided the required insights into the hydrogen storage options and costs. These will be critical in evaluating the cost of storage (CAPEX) against the operational (Demand Response) impacts on electricity pricing.

This work indicated that the required hydrogen storage for a few hours of Demand Response capability would be in the order of tens of millions of dollars.

6.5 Balance of Plant Impacts

While the electrolysers and eSAF plant are at the core of the production system, there are many utilities and other balance of plant elements that are required to support these.

As electrolysers lose approximately 30% of their energy to heat, the process cooling system is one of the key utility systems. The technology selection and sizing of this system is dependent on the required electrolyser capacity, so it is impacted by the Demand Response capability, and needs to be considered in the evaluation.

Another significant impact is the configuration of the plant layouts. Large quantities of hydrogen stored under pressure represent a significant safety hazard. Detailed safety modelling is required to determine potential safety events, and safety buffer zones required around the hydrogen storage. The safety buffer zone is a function of the quantity and pressure of the hydrogen storage, so different options result in different designs and hence impacts on the layouts.

6.6 Grid Connection and Constraints

The electrical demand of the plant (approximately 300 MW) will be one of the largest loads connected to the New Zealand grid.

Separate to the Demand Response modelling work undertaken by Jacobs, a second scope of work was awarded to determine an initial grid connection design and to undertake detailed grid constraint and impacts analysis.

This analysis had to consider the Demand Response elements, both on the impact of peak plant loads for different Demand Response capabilities, but also how the Demand Response capability could be used to avoid triggering/exceeding a grid constraint.

6.7 Impacts on Modelling Undertaken

As noted previously, the Jacobs Demand Response study was commissioned at the start of PFS phase, simultaneously with the other engineering and system studies, so assumptions were required to commence the work.

One of the assumptions used for the Jacobs scope of work was that the electrolysers could be turned up and down at will and turned down to 0%. The electrolyser study has shown that this assumption was flawed, and the modelling should use the assumption that electrolyser turndown should only be to 50%.

This does not negate the value of the modelling undertaken by Jacobs – there are clearly benefits to the greater New Zealand grid as well as to the project from Demand Response, but the modelling will be required to be updated at different intervals, utilising the constraints and component performance identified by the other areas of engineering.

The ability of the eSAF plant to provide overall throughput reduction should also be investigated. There may be a larger Demand Response function (i.e. rather than just turning electrolysers down for a few hours in a 24-hour cycle) where the entire plant could be turned down for weeks or longer in response to a “dry year” event, or significant generation failure in the system.

Additionally, if there is a grid constraint such as transmission system reduction in capacity in the peak of summer due to thermal issues, there may be the opportunity to operate the plant at 90% capacity for the peak summer month to ensure the grid capacity is not exceeded, and hence avoid a grid upgrade.

The evaluation of the larger Demand Response capability would need to consider the value of the loss of production, and any commercial impacts of reduced production as part of its evaluation.

The other output that the work detailed above has generated is the inputs required to enable the economic evaluation of cost and benefits of Demand Response to the project. The more accurate capital and operating costs for hydrogen storage, additional electrolyser capacity, eSAF production impacts and issues like grid constraints and impacts on layouts can now be used in the commercial evaluation.

7 BARRIERS / ENABLERS FOR DEMAND RESPONSE BENEFITS

Fortescue has commissioned Jacobs to undertake a regulatory scan of the policy and regulatory environment in which demand-side flexibility services operate in the New Zealand Electricity Market. The purpose of this report is to inform the decision-making process related to hydrogen storage option at a proposed eSAF plant at Marsden Point, near Whangarei in the upper North Island.

Engaging demand-side management – and the closely-related issue of ensuring capacity to meet peak load – has been a point of focus for several of the recent consultation and market design changes. As a result, the framework for encouraging demand-side participation has become much stronger with the development of real-time pricing and the associated demand-side participation options available. There is, in addition, an increasing clarity of some further developments that are likely to be necessary in the future.

However, there remain some hurdles to participation that are particularly relevant for the participation of industrial loads managing the practical implications of managing a flexible production profile. This report will highlight where the planned market development work programme might leave barriers in place that could be relevant to Fortescue, while recognising there is greater ability for a large, sophisticated participant in the energy market to overcome some of these barriers.

There is a broad consensus about the potential benefits of demand-side management, particularly in the context of facilitating efficient price signalling in a highly renewable energy future. An electricity market dominated by supply with zero or very low short-run marginal cost generation will require efficient pricing of flexibility services – including demand side flexibility – to allow efficient price discovery. In addition, demand-side flexibility could reduce overall system costs and carbon emissions by reducing the need for thermal peaking generation and network investment and improve resilience in the face of increasing physical climate risk.

However, demand-side participation in electricity markets has remained a relatively fringe activity due to several barriers to entry. These barriers have resulted in very low levels of engagement in demand-side options for all but the largest demand players and have likely stifled engagement even from large and sophisticated load participants. Market design will need to address these barriers if the objectives of unlocking demand-side flexibility are to be realised.

Since the introduction of real-time pricing – the final phase completed in April 2023 – the NZEM has provisioned for four demand-side categories depending on the size and sophistication of the load. These provide capacity-appropriate avenues for demand-side flexibility to interact with the spot market.

Between 2019 and 2023, the Electricity Authority commissioned three pieces of work that considered – amongst other things – the barriers to entry for demand-side participations and potential remedies. Our report draws heavily on the findings of those reports.

The Innovation and Participation Advisory Group produced a report in 2023 originally intended as a review of Transpower's demand response programme but ultimately became a review of the demand response environment in New Zealand and a proposed framework to implement.

In 2022, Stephen Batstone produced a report for the Market Development Advisory Group (**MDAG**), ‘Enhancing wholesale market demand side flexibility: Framework for Option Development’. This report fed into a broader work programme that culminated in a final report, ‘Price discovery in a renewables-based electricity system FINAL RECOMMENDATIONS PAPER’, which included a set of measures – including several related to demand-side participation – intended to ensure the market sends efficient price signals through the energy transition and beyond.

The key barriers to entry that the above work identified were:

- Historical dominance of fixed price variable volume tariffs suppressing dynamic price signals to consumers.
- Relatively stable electricity prices reducing the size of the prize.
- A wholesale electricity market and tools developed around interacting with a small number of large participants.
- High level of cost and effort of interacting with the market.
- Lack of available tools – particularly innovative flexibility contracts – to allow sellers and buyers of demand-side flexibility to engage with each and discover forward prices.

MDAG’s final report in 2023 included several measures targeted specifically at demand side flexibility (**DSF**), including information provision by participants, assistance from government agencies such as EECA, ensuring that market systems can incorporate large-scale demand-side participant while delivery security-constrained dispatch, and the development of standardised flexibility contracts to facilitate matchmaking and price discovery for flexibility services.

All but one of the measures MDAG linked to unlocking DSF are now on the EA’s work programme, an indication or the importance placed on DSF by MDAG and the EA. In March 2023, the Electricity Authority formally responded to MDAG’s report by publishing their intended work near-term programme. The published programme includes a prioritised set of the first two tranches of MDAG’s recommendations based upon EA views and public consultation. The EA expects to begin work on the remaining measures in tranche 1 and 2 by the end of 2025.

While not specifically targeted at DSF, investigation of an ahead market (MDAG recommendation 27 in tranche 3) is an area that could improve the engagement of large potential dispatchable demand participants. As highlighted by the Major Electricity Users Group in response to an EA consultation recently on addressing peak capacity issues, large industrial process often cannot reasonably reduce load in response to a single trading period of high prices. Large load participants could be substantially more engaged if they had more certainty that their response could be sustained by the market for at least several hours and they had a clear signal to prepare their plant ahead of time.

It would take several years to confirm that a day ahead market would provide and – if so – implement the necessary market design changes. The EA would need to carefully study the system-wide benefits and then model interactions with the real-time market to ensure that the addition of the proposed ahead market represented a genuine benefit to the efficient operation of the electricity market.

Some advocacy directed at prioritised and resourcing for the EA could increase the likelihood that the ahead market question is resolved by the time the proposed eSAF plant is commissioned. At this stage, the EA has only stated that they will start work on tranche 3 and 4 measures “in due course”. MDAG highlighted resourcing as a potential bottleneck in delivering the long list of recommendations to the aggressive timeline proposed. Given the number of initiatives and the potential for interaction, it would be prudent to assume that implementation of many measures could take longer than anticipated.

As a large, sophisticated industrial participant with electricity forming a key variable input cost, Fortescue is likely to be able to readily overcome the sorts of participation barriers identified. However, demand response of the scale and flexibility identified in this study could be pivotal to development of broader demand-side management activities.

8 DECARBONISATION BENEFITS OF ESAF PRODUCTION

The eSAF project provides an opportunity to assist in the decarbonisation of the aviation industry by producing locally made renewable fuel. The aviation sector is broadly viewed as a hard-to-abate sector. eSAF is a critical enabler to decarbonise global aviation. The International Air Transport Association (**IATA**), the trade association for the world's airlines, has estimated that eSAF will contribute up to 65% of the reductions required for the aviation sector to achieve net zero emissions[4].

In 2019, domestic emissions from the aviation sector in New Zealand were ~1 million tonnes of MtCO2-e with international flights contributing a further ~3.9 MTCO2e of emissions[5]. The eSAF project proposed at Marsden Point would assist in the decarbonisation of the aviation industry by displacing approximately 0.18 MtCO2-e emissions per year. This represents ~18% of emissions from the domestic aviation sector.

As part of the project, a full carbon accounting system will be required. This will include the carbon burden of all key inputs (CO2, water, input transport to the facility etc), carbon burden associated with power generation and any grid make-up, emissions from site such as use of gas, and transport of product to the end user.

eSAF produced at Marsden Point would have the benefit of being able to be used in existing airline fleets with no modification. The eSAF would be almost identical in composition to existing jet fuel, meaning it can be blended into existing supply chains and used in existing airline fleets.

Fortescue's eSAF project at Marsden Point would also provide the benefit of local production of sustainable fuel, alleviating fuel security concerns, together with the employment opportunities and resultant economic benefits to the region.

[4] **Source:** IATA – Fly Net Zero (https://www.iata.org/en/programs/environment/flynetzero/)

[5] **Source:** Managing Aotearoa New Zealand's greenhouse gas emissions from aviation (https://www.tandfonline.com/doi/full/10.1080/03036758.2023.2212174)

9 CONCLUSIONS AND RECOMMENDATIONS

The Project is currently in the pre-feasibility phase of studying the development of a green hydrogen manufacturing facility at Marsden Point to produce eSAF. The results from this phase of the study will assist in further evaluating the feasibility of an eSAF facility at Marsden Point and inform the decision whether to proceed to the feasibility study phase.

The Project has not identified any technical constraints that would restrict its ability to incorporate Demand Response capability. The Project will incorporate the ability to reduce power demand into the plant design, enabling some of the benefits outlined in this report.

9.1 Modelling Results

Market modelling results to date yielded the following core results:

1. The eSAF plant is a material increase in load relative to the existing N-1 import capacity and regional generation. As result, we expect some increase transmission capacity to be required to avoid price separation and potential load-shedding in Northland.

2. Additional transmission capacity could be reduced and/or deferred by flexible load and/or dispatchable generation in Northland.

3. Once the transmission constraint is resolved, the system benefit of hydrogen storage is relatively modest at the beginning of the modelling horizon but grows to NZD 25 million to NZD 50 million (real 2023) for four hours storage by 2045 (see section 5.2). We have estimated this stream of cashflows to be NZD 79 million to NZD 155 million (real 2023) when discounted at 7 % per annum to a present value 2024 figure.

4. Similarly, the private benefit to Fortescue (assuming the transmission constraint has been relieved) is modest in 2030 but grows upwards of NZD 50 million (real 2023) per annum from 2040 onwards. When discounted at 9.1 % per annum (more representative of the cost of capital for a private entity), this stream of benefits comes to NZD 66 million.

5. Two operational strategies have been modelled. The first is a Power Cost Minimisation strategy where the electrolyser load is flexed (turned down) using the available hydrogen storage in response to spot price. The second a Self Consume strategy where Fortescue operates the electrolyser and storage to prioritise internal use of PPA generation (section 4.1), reducing market risk to Fortescue.

   Both strategies see cost reductions to the LWAP as a result of demand management, however the self-consumption strategy has less impact as the amount of demand response potential is reduced.

6. Fortescue's benefit per unit of storage appears to decline beyond two hours but system benefit continues to increase approximately linearly for the storage durations studied (see Figure 19 below).

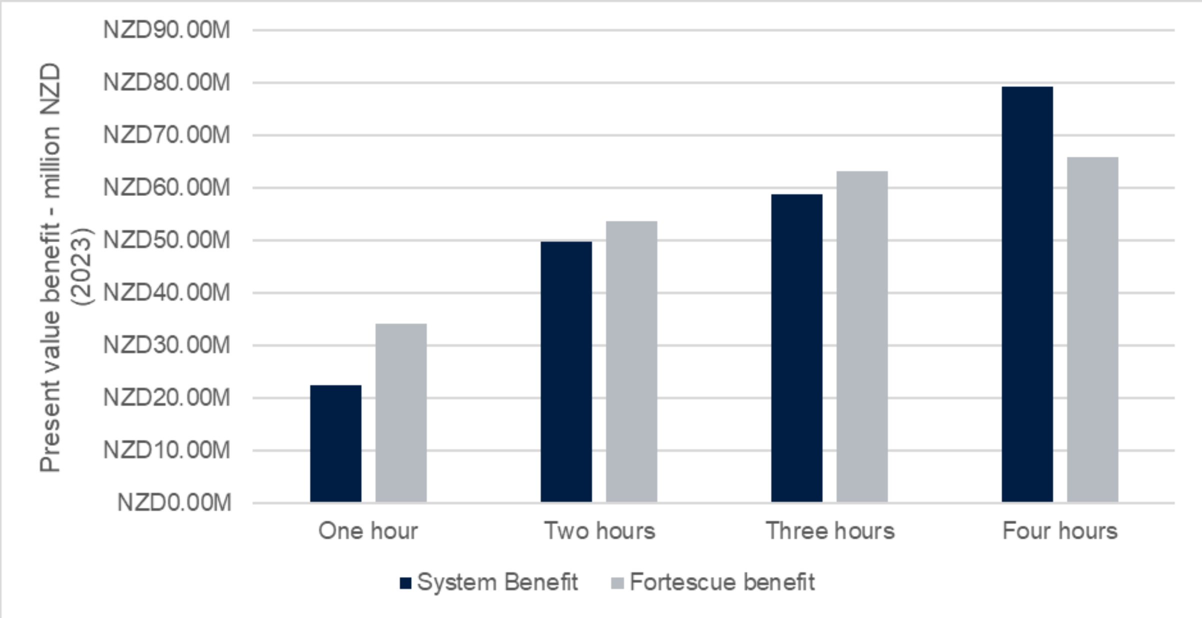


Figure 19: System and Fortescue present value benefits

9.2 Insights into the Viability of an e-SAF Facility

The Project is currently in the pre-feasibility phase of studying the development of a green hydrogen manufacturing facility at Marsden Point to produce eSAF. The results from this phase of the study will assist in further evaluating the feasibility of an eSAF facility at Marsden Point and inform the decision whether to proceed to the feasibility study phase.

9.3 Other Work Undertaken

Work in other areas of the project have helped establish the constraints, costs and impacts of Demand Response on the overall development. These learnings can then be incorporated into the next round of Demand Response modelling.

The work has also indicated the opportunity for larger (i.e. greater than 4 hour) Demand Response by turning down the eSAF plant, but this will need to be evaluated for the impact on production and overall project economics.

9.4 Recommendations and Next Steps

The work has clearly demonstrated the value and opportunity for Demand Response to benefit the project and overall New Zealand community. Given the early phase of the project, the following further work should be undertaken:

1. Updating of the hydrogen storage Demand Response modelling with the identified constraints of 50% electrolyser turndown.

2. Demand Response modelling for the larger eSAF plant turndown.

3. More detailed evaluation of grid constraints, and the projects' ability to positively influence the required grid updates and management as both overall load and greater intermittency impact the grid in the future.

4. Economic evaluation of the various Demand Response options to better understand benefits and costs to both the project and the greater New Zealand grid and consumers. This evaluation should consider timing (i.e. near term or delayed into the future) for Demand Response services to the market.