MDAG DSF Case studies

MDAG DSF Case Studies – Scenario descriptions

In the MDAG **reference** scenario, demand side flexibility was assumed to exist in the following forms in 2035:

a) 600MW of elastic (curtailable) demand, triggered at prices between $700/MWh and $1,500/MWh.

b) 423MW of electric vehicle charging that could be shifted by up to 5 hours in response to wholesale prices. This is equivalent to around 70% of the **average** charging load from the combination of 1.7M light EVs, and 40k heavy EVs[1] being made available for dynamic wholesale response. In reality, it is likely to be a mix of charging from passenger and larger commercial/heavy vehicles.

c) 400MW of rooftop solar batteries, which could be used to shift demand by up to 5 hours. This combines with an assumption that there is 1.3GW of installed rooftop PV (e.g., 260,000 installations of 5kW each, with a 30% penetration of combined solar/battery systems).

MDAG also tested a **low demand response scenario** (halving the figures above) and an **enhanced flex** scenario, which scaled up the EV charging from 70% to 100%, but also included a flexible demand source (e.g., hydrogen electrolyser) which can vary between 0MW and 400MW at prices between $30/MWh (400MW) and $300/MWh (0MW).

1. Assumptions primarily derived from the CCC as follows: More explicitly, 1.7M light passenger and commercial EVs (41% of the total light fleet) driving on average 13,700km per year at an efficiency of 18kWh/100km. A further 40,000 medium and heavy trucks and buses, driving 29,000km per year at between 72kWh/100km and 125kWh/100km. Total annual energy requirement of 5.3TWh
2. Technically, the flexible demand replaced an equivalent level of baseload demand

MDAG DSF Case Studies - Overview

We have used results from the MDAG wholesale market modelling to evaluate examples of how DSF may be used, and whether it is worth pursuing.

Caveats:

1. **System is in equilibrium**: The model is "in equilibrium", which means that all economic investments (including grid-scale batteries), plus assumed level of DSF, have been made; thus the "prize" of demand-shifting has already been partly captured (and volatility commensurately lowered). However, **modelling suggests system benefits (i.e., the avoided cost of these investments) is ~$114/kW-y**.
2. **Non-wholesale DSF**: Similarly, the modelling assumes 60% of EV DSF has been activated by distribution companies (40% remaining is convenience charging), on the assumption that by the time that 1.8m EVs appear, network congestion will have become an imperative to address through controlling EV charging (ref e.g., Vector's Symphony strategy). This essentially "smooths" the profile of EV charging, leaving lower scale of flexibility for wholesale. Chicken and egg problem, but assumption is that networks will act first.
3. **Modelling limitations**: The model does not have a detailed representation of intra-week and intra-day volatility. However, it also assumes perfect foresight. The reality of (likely) higher intra-week volatility, but lower predictability, than modelled may offset each other to some degree. Model does not evaluate V2G.
4. **No price response for larger DR**: The analysis being applied 'ex-post' to the model run: that is, no amount of demand reduction will change (reduce) the price.

MDAG DSF Case Studies – EV charging

MDAG 100%RE prices to estimate value of EV charging challenged by both caveats 1 and 2 on previous slide. Industrial DSF not exposed to caveat 2, as there is no assumption in the model that industrial consumption is used to manage network congestion.

We can use the estimated "average system benefit" ($114/kW-y) of short-term load shifting as a proxy to correct for caveat 1. By way of comparison, Frontier (for Vector) estimated that the whole-of-system-cost reduction from smart EV charging was ~$111/kW-y (network + wholesale), with a wholesale component of $100/kW-y. This used a simpler approach to estimating wholesale benefits.

This can be used to compare with e.g., costs of smart EV chargers (EECA green paper)

- Suggests (conservatively) a smart charger on a standard 1.8kW/8A connection worth ~$210/y in wholesale system benefits; $285/y if adopt shiftable charge of 2.5kW per Frontier report.
- <u>If these wholesale system benefits are passed through to consumer</u>, NPV of benefits to consumer (10Y, 6%) = ~$1,500, which is ~60% of the cost of a Evnex smart charger today ($2,500).
- Network value would add to that. Other work (Sapere, Concept, Orion etc) suggests average LRMC or LRAIC of distribution between $60/kW-y - $100/kW-y (not including transmission), but how much of that can be delivered in a particular place in the network requires deeper analysis.

MDAG DSF Case Studies – Industrial DSF usage

We simulated two forms of industrial demand response:

- A process heat consumer utilising hot water storage to shift demand within the day
- A process heat consumer using an alternative (non-electric) fuel supply to provide heat needs for prolonged periods

Within the constraints of our model, we attempted to simulate the operational reality as close as possible[1].

We compared the wholesale purchase costs of the process heat consumer with and without DSF. We evaluated two scenarios:

- The MDAG base case, which assumed that efficient grid-based investment had taken place, and around 800MW of other DSF (residential hot water, batteries and EV charging) was already deployed.
- The MDAG “low demand response” case, where only 400MW of other DSF was deployed, resulting in higher short-term volatility.

1. We are grateful for the assistance of Roger Sutton (CE, Electricity Ashburton) and DETA for assistance in this regard

DSF Case Study: Industrial Process Heat User: Demand shifting

CASE DESCRIPTION

Type: Industrial user of process heat (meat processing profile)

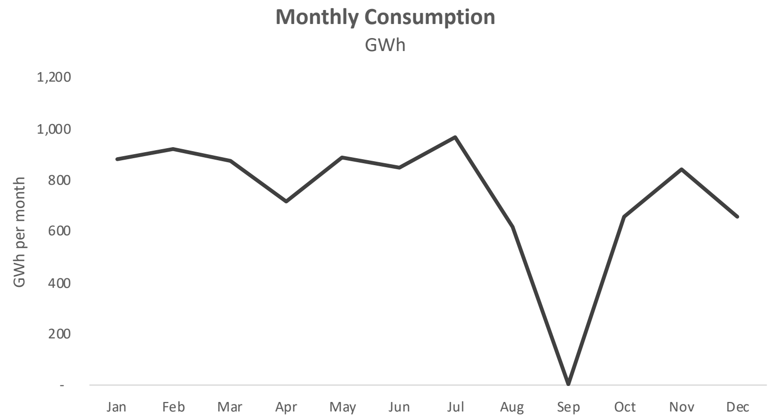
Location: South Island

Heat type: Hight Temperature Heat Pump, 2.5MW capacity

Annual Demand: 9GWh

Avg Annual Wholesale Purchases (in MDAG base case): $0.63M

Avg Load-Weighted Electricity Price: $73/MWh

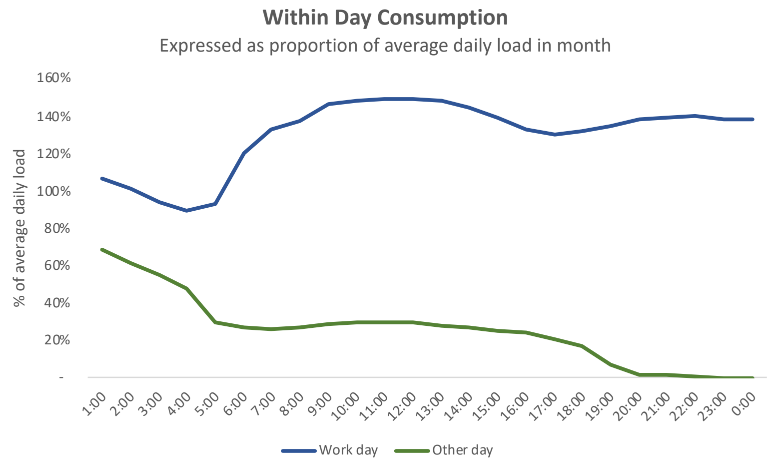


DSF CHARACTERISTICS

Industrial user utilises hot water storage to **shift water heating demand up to 5 hours**.

We assume this can happen every day; in reality the recharge time of the storage (once drawn down) is likely to be a number of days when relying on waste heat from refrigeration.

However, quicker recharge could be provided by an additional backup/top-up boiler (electric, diesel or wood), but this would be an additional cost to the user.



DSF Case Study: Industrial Process Heat User: Demand shifting

How much can the industrial user reduce its purchase costs by shifting water heating demand by 5 hours?

RESULTS

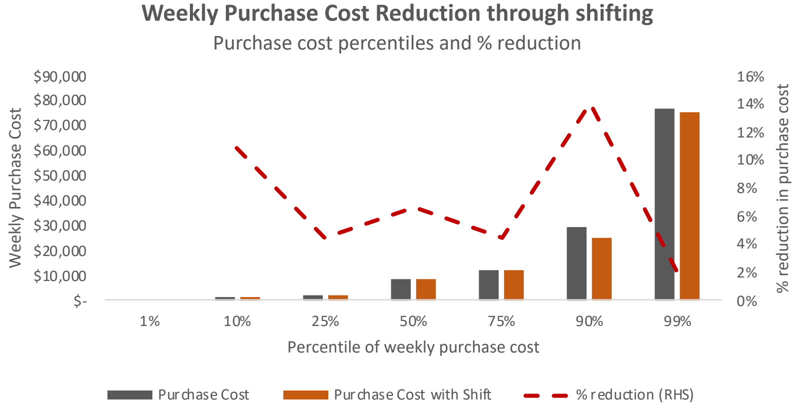
	Base Scenario	Low DR scenario
Purchase Cost per annum; no demand shift (average)	$629,000	$685,000
Reduction in purchase cost with demand shift (average)	$52,000	$128,078
Reduction as % purchase costs	8.2%	18.7%

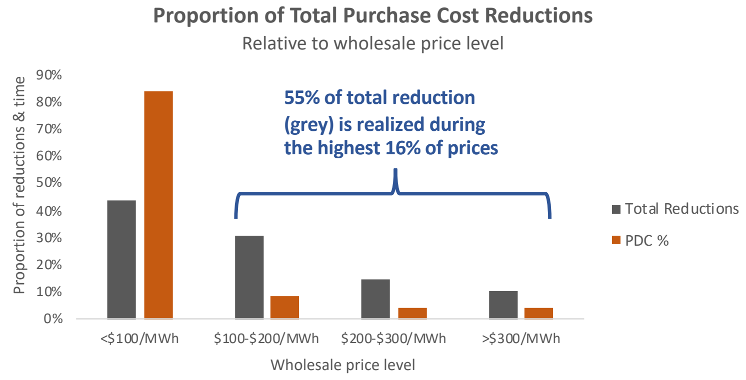
WHEN IS DEMAND SHIFTING MOST VALUABLE?

Greatest <u>proportional</u> reduction in purchase cost is being achieved when purchase costs are very low (10% reduction when purchase costs at 10^{th} percentile levels) or high (11% reduction at 90^{th} percentile purchase costs) – indicative of intra-day volatility.

Around 55% of the total reduction in purchase costs occurs when daily average prices are over $100/MWh – and these prices occur only 16% of the time

When purchase costs are very high, only a small improvement in costs is seen – potentially because prices over the day are consistently high (so no significant gain from shifting).





DSF Case Study: Industrial Process Heat User: Alternative fuel

CASE DESCRIPTION

Type: Industrial user of process heat (meat processing profile)

Location: South Island

Heat type: Electrode Boiler, capacity 10MW

Alternative boiler: Thermal, $100/MWh delivered heat.

Annual Demand: 34GWh

Avg Annual Wholesale Purchases (in MDAG base case): $2.5M

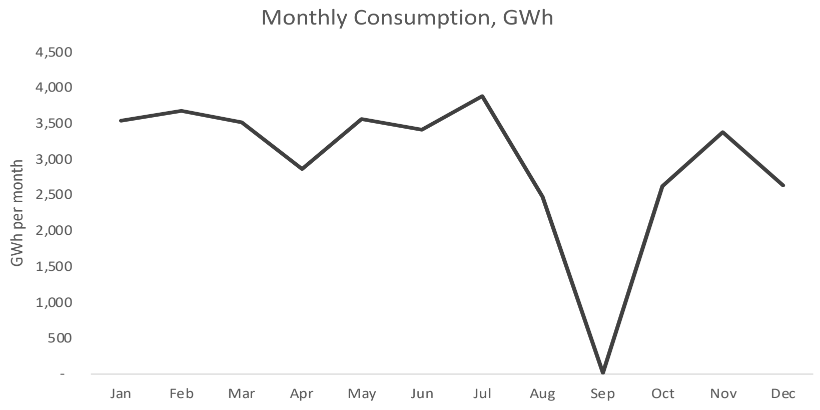
Avg Load-Weighted Electricity Price: $73/MWh

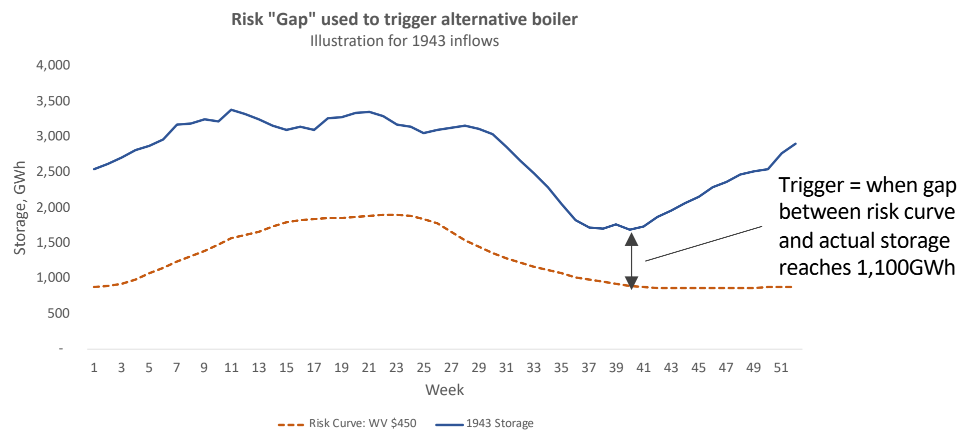
DSF CHARACTERISTICS

We use the scenario where the process heat user has switched from a coal boiler to an electric boiler. However, they choose to retain their old coal boiler for resilience, and also to provide an alternative fuel when electricity prices get high.

The logistical issues that arise when re-starting the old boiler mean that this is only likely to be activated when it is expected to run for a prolonged period, i.e., a low inflow period.

Therefore, we assume the process heat user relies on observed storage levels as a trigger to switch to the alternative boiler. A simplistic analysis suggests triggering the alternative boiler when the “risk gap” reaches 1,100GWh maximises savings.





DSF Case Study: Industrial Process Heat User: Alternative Fuel

How much can the industrial user reduce its purchase costs by running an alternative boiler when the lakes go low?

RESULTS

	Base Scenario	Low DR scenario
Purchase Cost per annum (average)	$2,518,000	$2,740,000
Reduction in purchase cost (average)	$411,760	$472,600
Reduction %	16.3%	17.2%

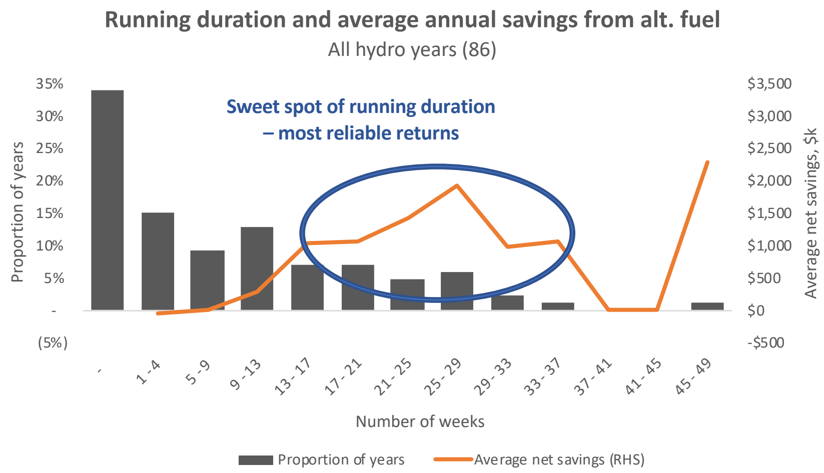
HOW IS THE ALTERNATIVE BOILER BEING USED (BASE)?

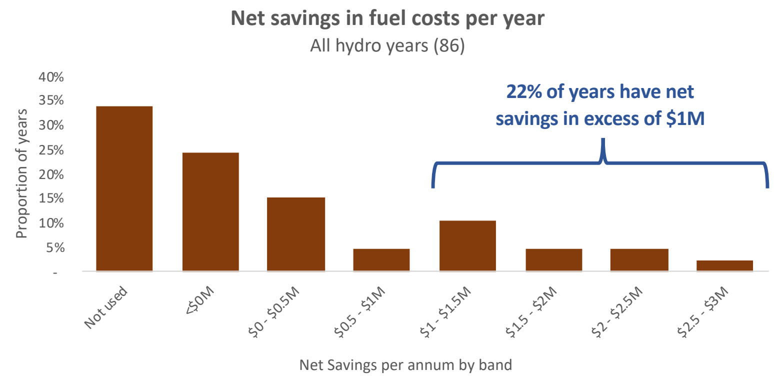
In the base scenario, the alternative boiler is not being used at all in 33% of inflow years simulated.

In other years, usage ranges from short periods (1-4 weeks) up to running most of the year. This is a significant range for which alternative fuel is assumed to be available for.

In 25% of years, operating the alternative boiler to a hydro-based trigger results in <u>increased</u> net costs (prices don't rise sufficiently to cover cost of boiler). The majority of these are shorter periods (1-12 weeks) where a more sophisticated trigger could reduce this effect.

The running duration that generates the largest source of net savings seems to be 4-7 months – this accounts for 22% of years where at least $1M of savings are generated.





DSF Case Study: Industrial Process Heat User: Demand shifting

There are a number of practical considerations in keeping a standby boiler available, does the business case stack up?

ANNUAL CERTIFICATION?
Certification of a 10MW boiler is estimated to be ~$100k and expires annually. This could be renewed annually, or only when hydro trigger is reached.

FUEL CHOICE?
Maintaining access to coal would incur the lowest costs, at least in the short run. Conversion of a boiler to e.g., wood pellets is estimated at $400k/MW, and supply chain may not be reliable.

LABOUR?
Skillset to stoke a coal or biomass boiler potentially different to electrode – doubling up on labour costs?

Choosing to certify annually, plus a boiler conversion (to biomass) would result in a 10-year NPV of -$2M.

Choosing to certify annually, and retaining coal as the backup would have a NPV of $2M.

Improved triggers for operation (e.g., combination of rolling average price and risk level) could improve cost reductions.

Retailers may offer dry-year reserve retail contracts with favourable prices, and more effective triggers.

Should a RERT-style scheme be established, possibility for additional revenue.

Case studies - what did we learn?

- Responding to modelled wholesale signals provides material purchase cost savings (if on wholesale tariff) in the two industrial situations simulated, even in a world where some volatility has already been arbitraged away by other short-term flex options.

- In the base case, being able to respond to **medium term** scarcity is worth ~2x **short-term** load shifting; competing only with $480/MWh green peakers.

- But the cost of enabling medium term flex might be significant, and may make the difference between a positive and negative overall investment value.

- Value extracted from dynamic EV charging is low if significant control undertaken for network reasons – a further form of "competition" for the arbitrage value.

- Again, the presence of material wholesale value begs the question of whether commercial arrangements (tariffs) will emerge that share benefit and control between intermediary and customer, or will the customer have to go on a spot tariff and DIY?