QUANTIFYING DEMAND-SIDE FLEX

Data and modelling Report

ENERGY EFFICIENCY & CONSERVATION AUTHORITY
TE TARI TIAKI PŪNGAO

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1. Foreword

This report is one of a suite of reports documenting research to quantify the potential of industrial demand-side flexibility in the New Zealand Electricity Market (NZEM)

As the country moves towards a more sustainable and resilient energy future, understanding and harnessing the power of DSF becomes increasingly crucial. This study aimed to provide a detailed assessment of the current landscape, potential, and pathways for implementing DSF across various sectors of the New Zealand economy.

The primary objectives of this research were to:

- Evaluate the current state of demand-side flexibility in New Zealand through a thorough literature review and stakeholder engagement.
- Quantify the potential for DSF across different sectors and regions of the country.
- Identify barriers and enablers for DSF implementation.
- Develop recommendations for unlocking the full potential of DSF in New Zealand.

To achieve these objectives, our research team employed a multi-faceted approach, combining data analysis, modelling, and stakeholder input. The study leveraged international best practices while adapting methodologies to suit the unique characteristics of New Zealand's electricity system.

By providing a comprehensive analysis of DSF potential in New Zealand, this suite of reports aims to inform policymakers, industry stakeholders, and researchers, ultimately contributing to the development of a more flexible, efficient, and sustainable electricity system for the country.

2. Executive Summary

This report documents the data and modelling approaches and outcomes from this research.

The report is structured as follows:

- Load data collection and processing: This section covers the load data collection approach and processing that formed the basis for the demand-side flexibility modelling.
- Modelling methodology: This section documents the modelling methodology and development process.
- Modelling outcomes: This section presents modelling outcomes.

Data collection and processing

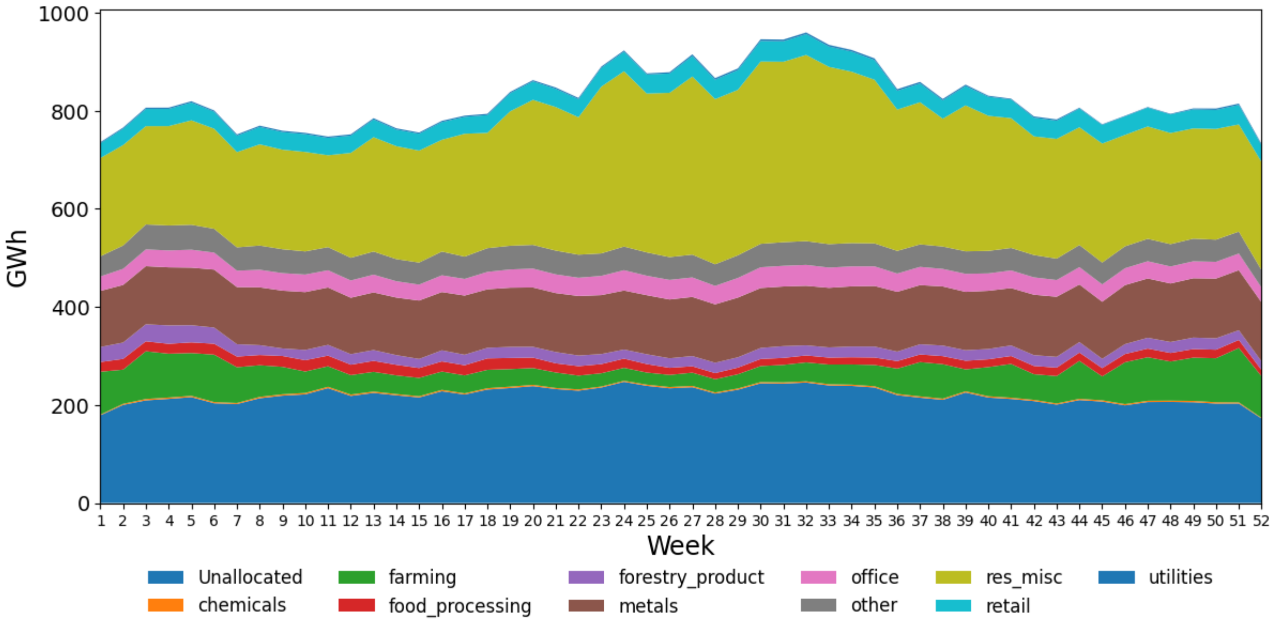
The objective of the data collection and processing phase of the research was to build a load dataset that met the following criteria:

1. Collectively exhaustive: covers all consumer electricity demand connected to the NZEM
2. Mutually exclusive: does not double count any load
3. Sectoral resolution: is disaggregated based on ANZSIC codes to at least level 3

4. Regional resolution: aggregated to regional level
5. Trading period resolution: collected at 30-minute resolution
6. At least one year duration

The resulting dataset is, to best of our knowledge, the only electricity load dataset collected in New Zealand that meets all the criteria set out above and we expect it to continue to provide valuable insights beyond the life of this project.

Figure ES 1 National weekly load data by sector aggregation



Daily profiles by sector are available in the appendix of this report.

Modelling approach

The model estimates demand-side flexibility based on clusters of pre-determined load profiles using total national level demand to construct a governing DSF signal.

A load cluster is defined as a unique combination of various subsectors (office space, metal industry etc.) with in a broader high-level categorisation which are industrial, commercial, and residential consumers which at a higher level is further classified based on regions.

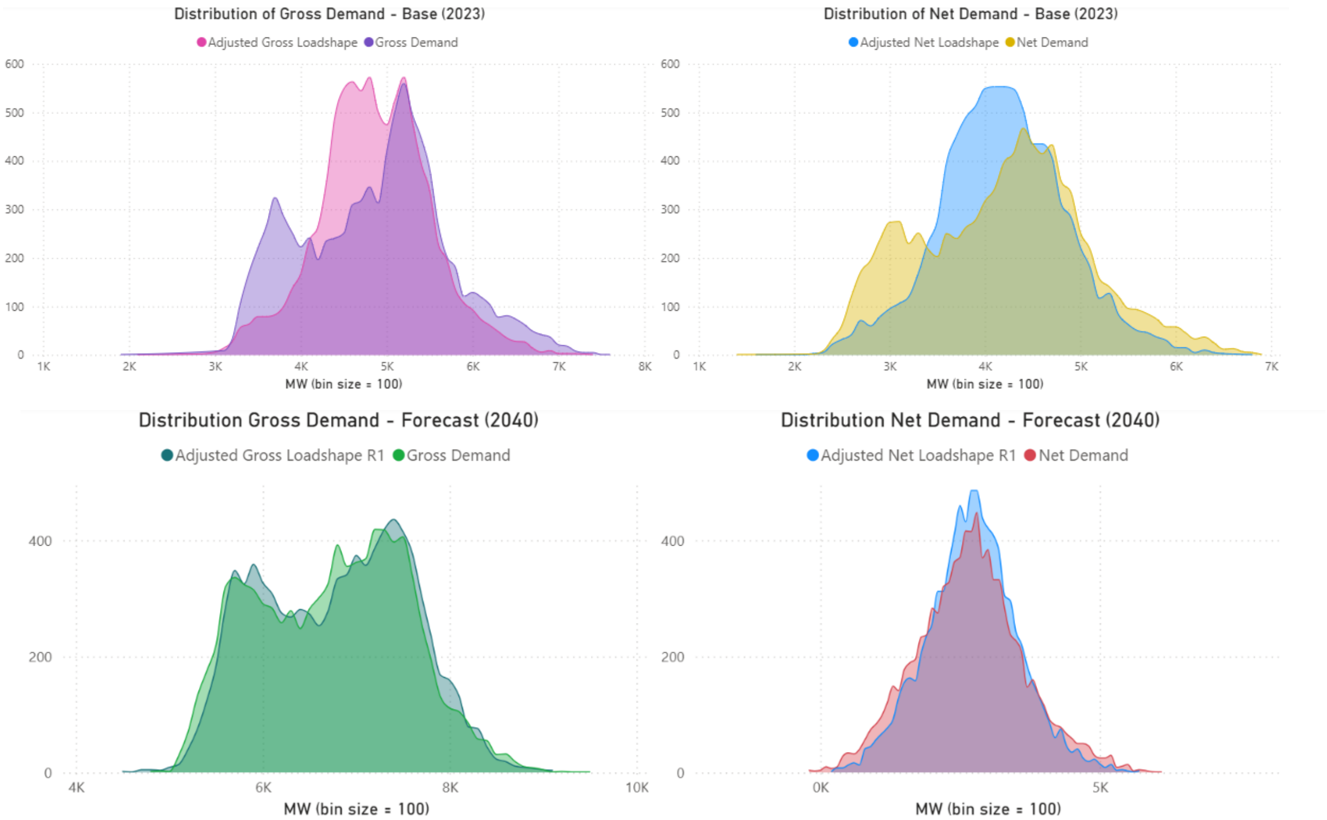
The current version of the model makes use of 165 load clusters. The modelling approach consists of the following high-level steps:

1. Deriving a national level DSF signal for estimating shift and shed potential
2. Calculation of DSF features to be used in cost estimation
3. Costing framework to assess the economic viability of DSF potential

Modelling outcomes

Demand side Flexibility, particularly the shifting of demand from peak period to off-peak periods (shift DSF) has the potential to significantly reduce the magnitude and the frequency of very high and very low load. The graph below illustrates the potential (before costs are considered) impact of shift DSF on the national gross and net demand. Note the distribution (shown in figure ES 2) of the adjusted load shape for 2023 is more condensed than the original gross or net demand, indicating peak loads are being reduced and off-peak loads are being increased.

Figure ES 2 Gross/Net demand distribution before and after load-shifting



A key difference seen in the 2040 DSF forecast compared to 2023 DSF is that the shift DSF predominantly moves peak demand to dispatch intervals with cheaper renewable energy due to the much higher penetration of wind and solar in 2040 relative to 2023. As a result, the model sometimes creates new peaks in gross load during the day, resulting in a similar distribution of gross load after DSF (see bottom-left chart above). In other words, the peak end-use demand across the day is often similar before and after DSF, but DSF moves the timing of the peak to coincide with the maximum contribution of solar.

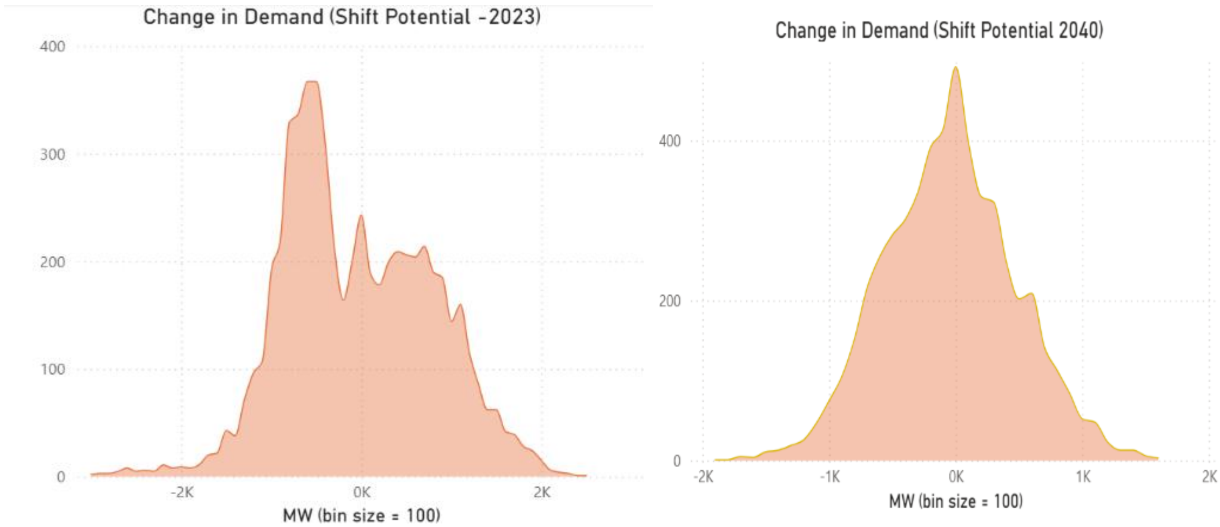
The remaining shift DSF (outside of the ones coinciding with RE generation) can be seen in net load distributions and they compress the resulting distribution, reducing the frequency of very high and low load periods.

It is important to note this model does not consider inter-regional transmission constraints which could be a limiting factor in achieving the modelled DSF potential in 2040 given the behaviour described above.

Shift potential tends to be dominated by the residential sector across the main centres due to the strong correlation between residential load and national load but there are some industrial sectors that stand out in some regions such as farming in across Canterbury, forestry in the Bay of Plenty, Gisborne, Hawkes Bay, and Manawatu, and metals in Auckland and Southland. As heat processes electrify over the coming years, the potential DSF available in the food processing sector is likely to increase significantly.

The national-level distribution of the change in demand due to DSF (Figure ES 3) for the 2023 base year shows that most load reductions fall under 1,000 MW per interval, with most intervals concentrated around 400 MW to 800 MW. In contrast, intervals with a net increase in demand exhibit a more even spread between 100 MW and 1,000 MW. For the forecast year 2040, the distribution for both net reductions and increases in demand appear more centered.

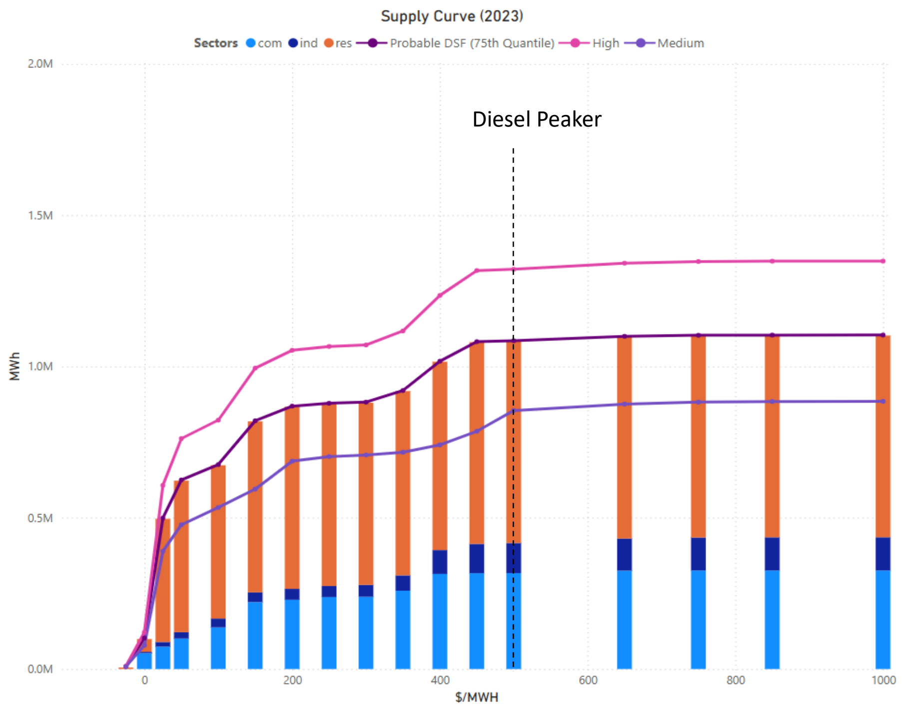
Figure ES 3: National shed and take distributions

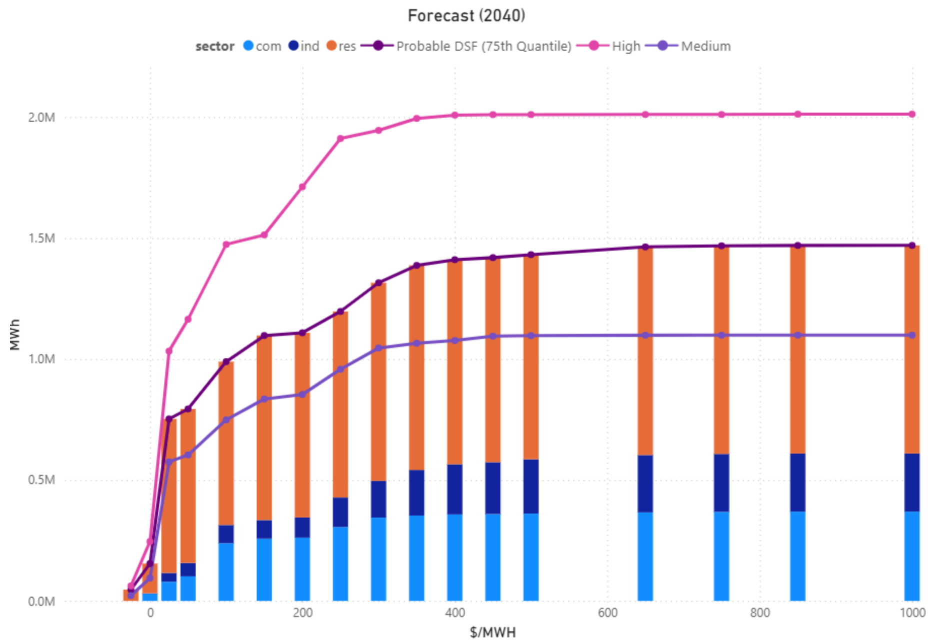


Analysis of diurnal energy profile show that most regions show a reasonable level of alignment in terms of *shifts in* energy compared to the national profile, with Southland being the main exception due to its flatter load profile dominated by demand at the aluminium smelter. Additionally, DSF in regions such as West Coast, South Canterbury, and Taranaki is misaligned in the intervals that capture the highest quantum of energy.

The supply curve in figure ES 4 represents the energy output from shift DSF following the economic assessment. The model estimates 1,083 GWh of energy could be accessed at a procurement price of $500/MWh against the probable scenario (75th quantile) for the base year 2023. During the forecast year of 2040 the total energy at $500/MWh increases to 1431 GWh due to proportionate increase across the section with minimum increase seen for the commercial sector. These prices are comparable to the current operating cost of a diesel generator.

Figure ES 4 Shift supply curves





3. Acknowledgements

EECA would like to acknowledge the invaluable contributions of data providers and survey respondents in this work.

Respondents			
McAlpines Ltd	Pukepine Sawmills (1998) Ltd	Graymont	Meridian Energy
Winstone Wallboards Limited	Oji Fibre Solutions	ANZCO Foods	Simply Energy
Methanex New Zealand	Astro pine ltd	Pan Pac Forest Products Limited	Genesis Energy
Whakatane Growers Ltd	Sequal Lumber Limited	Dominion Salt Ltd	Mercury Energy
Comfortech Building Performance Solutions	Kiwi Lumber	Fonterra	Network Tasman
DB Breweries Limited	WML	Cottonsoft	Waipa Networks
Timberlands	Pure Bottling	Fulton Hogan Ltd	Scanpower
Inghams	Alsco	Oceania healthcare	Alpine Energy
Tegal	The Tasman Tanning Co	Timberlands	Horizon Energy Distribution Limited
			PowerNet

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4. Acronyms and abbreviations

ACRONYM	Full Name
ANZSIC	Australian and New Zealand Standard Industrial Classification
Berkeley Lab	Lawrence Berkeley National Laboratory
CC	Customer Count
CR	Co-benefit Ratio
DER	Distributed Energy Resources
DERMS	Distributed Energy Resources Management System
DR-PATH	Demand Response Model developed by Berkeley Lab
DSF	Demand Side Flexibility
DSO	Distribution System Operator
DWP	Dispatch Weighted Price
EA	Electricity Authority
EDB	Electricity distribution business
EECA	Energy Efficiency and Conservation Authority
EEUD	Energy End-Use Database
EMI	Electricity Market Information
EMS	Energy Management Systems
ENA	Electricity Networks Aotearoa
ESS	Energy Storage System
EV	Electric Vehicle
f	Capital Recovery Factor
FC	Fixed Initial Capital Cost
FO	Fixed Operating Cost
GHG	Greenhouse gas
GXP	Grid Exit Point
HVAC	Heating, Ventilation, and Air Conditioning
IC	Incentive to consumers
ICP	Installation Control Point
ICT	Information and communication technology

ACRONYM	Full Name
IEA	International Energy Agency
kWp	kilowatt-peak
LBNL	Lawrence Berkeley National Laboratory
LF	End use constraint factor
LT	Loss
MBIE	Ministry of Business, Innovation and Employment
MDAG	Market Development Advisory Group
Mt	million tonnes
MW	Megawatt
MWh	Megawatt-hour
NPV	Net present value
NZAS	New Zealand Aluminium Smelters
NZEM	New Zealand Electricity Market
PPA	Power Purchase Agreement
RE	Renewable Energy
RETA	Regional Energy Transition Accelerator
TJ	Terajoule
TL	Technical Limit
TOU	Time of Use
TSO	Transmission and System Operator
UC	Uptake Cap
VC	Variable Initial Capital Cost
VO	Variable Operating Cost
VRE	Variable Renewable Energy

5. Purpose of this report

This report documents the data and modelling approaches and outcomes from this research.

The succeeding parts of the report is structured as follows:

- Section 6 - Load data collection and processing: This section covers the load data collection approach and processing that formed the basis for the demand-side flexibility modelling.
- Section 7 - Modelling methodology: This section documents the modelling methodology and development process.
- Section 8 - Modelling outcomes: This section presents modelling outcomes.

6. Load data collection and processing

This section provides a detailed description of the load data development process used in preparation for using DR-PATH[1] in the New Zealand context.

The objective of the data collection and processing phase of the research was to build a load dataset that met the following criteria:

1. Collectively exhaustive: covers all consumer electricity demand connected to the NZEM
2. Mutually exclusive: does not double count any load
3. Sectoral aggregation: disaggregated based on ANZSIC codes to at least level 3 and reaggregated into a sectoral cluster format for demand side modelling
4. Regional resolution: aggregated to regional level
5. Trading period resolution: collected at 30-minute resolution
6. At least one year duration

The resulting dataset is, to best of our knowledge, the only electricity load dataset collected in New Zealand that meets all the criteria set out above and we expect it to continue to provide valuable insights beyond the life of this project.

6.1. Retailer Data

The primary source for load data was electricity retailers who agreed to share large volumes of data with us for the purposes of this project. Through initial discussions with distribution businesses (EDBs) and retailers, it became clear that retailers were best placed to provide data that consistently met our criteria due to their geographical spread, billing role, and reporting requirements.

Jacobs requested data sets from several retailers which classified half-hourly demand curves according to region and sectors. The regional classification was based on the Regional Energy

[1] DR-PATH is the demand-side flexibility model built by Lawrence Berkely National Laboratories that was used as the basis for our model development

Transition Accelerator (RETA) definition used by the Energy Efficiency and Conservation Authority (EECA) as shown in Table 1.

Table 1. Regional classification

Region_ID	Region_Name
1	Northland
2	Auckland
3	Waikato
4	Bay Of Plenty
5	Gisborne
6	Hawkes Bay
7	Taranaki
8	Manawatu-Wanganui
9	Wellington
10	West Coast
11	North Canterbury
12	South Canterbury
13	Otago
14	Southland
15	Nelson-Marlborough-Tasman

Demand data was processed using sectoral classification based on the 2006 Australian and New Zealand Industry Classification (ANZSIC) with addition of Residential demand. These sectors were re-aggregated to reduce the number of groupings to be processed in the demand-side flexibility modelling phase of the study. The groupings are shown in 0

6.2. EMI data

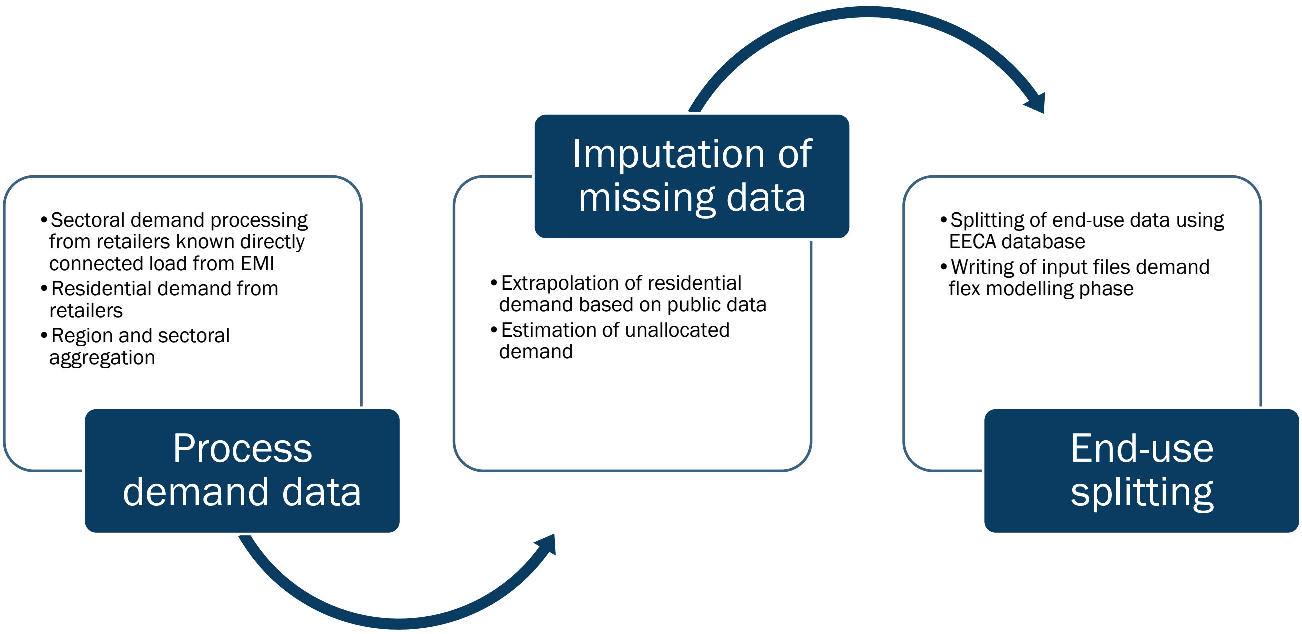
We collected EMI data to provide a comprehensive reference point for all demand to ensure that the dataset satisfied the requirement to be mutually exhaustive. The retailer load data was not a complete set as we were only able to collect data from a subset of retailers. Therefore, another data source which has a complete view of half-hourly demand was required. EMI data is a complete set and makes a credible baseline reference. Using this allows gaps from collected data to be filled in holistically, and with a high degree of accuracy.

The EMI data also includes load for direct connect industrial load which was not included in the retail data but accounts for a significant share of total national demand. EMI data collected included Grid Export, Grid injection, and Embedded Generation data to enable representation of demand gross of embedded generation.

6.3. Demand Processing Methodology

A python notebook was written to collate and process the demand data,[2] and its workflow is as follows:

Figure 1. Demand data processing workflow



The first stage of the process deals with electricity market demand data from EMI. GXPs were classified into the geographic regions and, for GXPs representing direct connect load, ANZSIC sectors from**Error! Reference source not found.**. We then aggregated load by timestamp, region, a nd ANZSIC ID to provide half-hourly load by region and sector. Note that, at this point, all load other than direct connect load customers is "unallocated" or ANZSIC ID 9999.
The next stage in the process handles respective datasets provided by the retailers who agreed to share demand data. Note that each retailer dataset has their dedicated treatment in the code because the data they shared were in different formats, requiring slightly different processing to achieve a common format for collation with the EMI data. We then aggregate retailer data by timestamp, Region ID, and ANZSIC ID to produce the total retailer reported half-hourly load by region and sector.

At this point of the processing, there is some demand that is double-counted in the EMI data and the retailer data, so we subtract the half-hourly total retailer load by region from the total half-

[2] (Process Demand – 2023.ipynb, available in the script package associated with this report). At the minimum, the virtual environment to run the code should contain the following libraries (as indicated in the attached requirements.txt file): Pandas, Os, Csv, Matplotlib.pyplot, Calendar, Datetime

hourly EMI load by region and merge them into a single dataframe to produce a dataset that has the same total demand as the EMI dataset but captures the sectoral allocation provided by the retailer data.

Missing Data Imputation

With approximately 43% of the EMI demand remains unallocated as the sum of the volumes reported by the retailers is significantly smaller than the sum of the EMI demand for all regions.

Missing load was predominantly residential load due to two factors:

- Mercury residential data was not included in the dataset.
- Trustpower data was missing from the Mercury data.
- Contact Energy chose not to share their data.

As a result, the retailer data includes only Meridian and Genesis residential data, representing 13% to 36% of residential ICPs depending on the region according to EMI retail share data. Therefore, we used the total amount of regional residential data from Meridian (MERI) and Genesis (GENE) as the basis for scaling up to fill up the missing residential demand per region. This is possible given the data on regional residential ICP counts from The Electricity Authority and the assumption that we had enough residential ICPs represented in each region that scaling would be a reasonable estimate of the missing load.

Table 2. ICP Count

Region	Total Residential ICPs	GENE + MERI Residential ICPs	GENE + MERI share of Residential ICPs
Auckland	609,924	113,329	19%
Bay of Plenty	194,319	40,429	21%
Gisborne	21,276	3,595	17%
Hawkes Bay	69,322	11,103	16%
Manawatu-Wanganui	100,576	34,406	34%
Nelson-Marlborough-Tasman	67,116	8,968	13%
North Canterbury	234,627	75,211	32%
Northland	82,008	23,609	29%
Otago	47,974	10,630	22%
South Canterbury	51,779	15,808	31%
Southland	93,450	17,982	19%

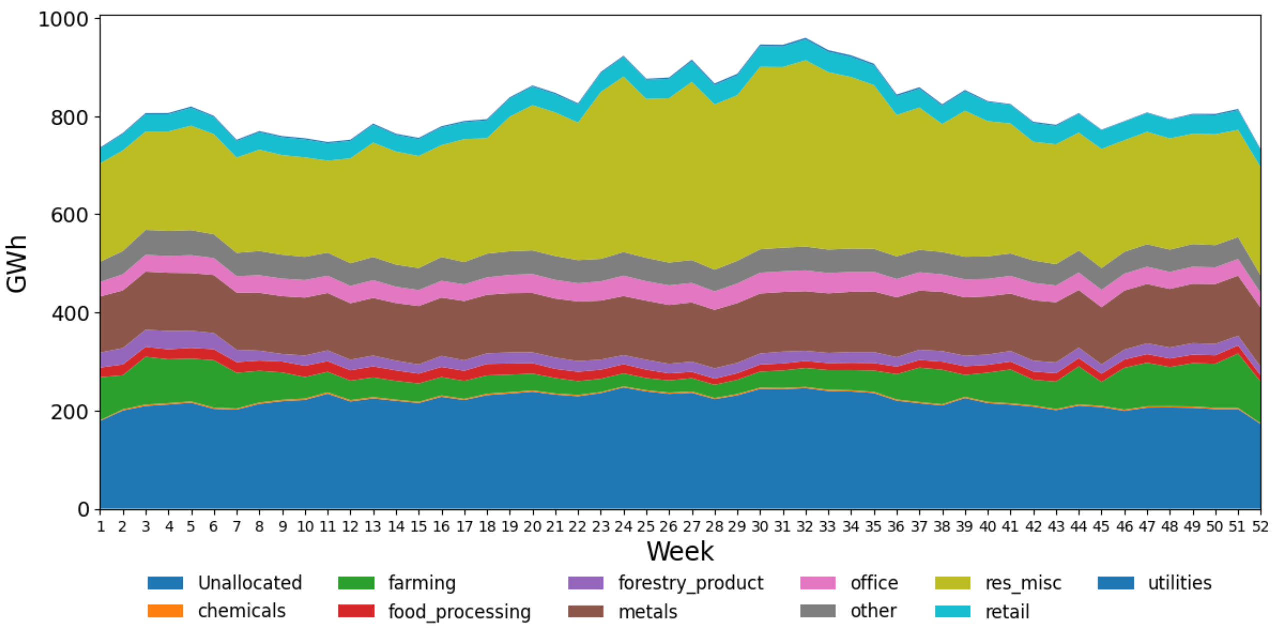
Taranaki	49,791	18,038	36%
Waikato	144,843	46,041	32%
Wellington	204,351	70,440	34%
West Coast	15,741	2,035	13%

SOURCE: THE ELECTRICITY AUTHORITY (EMI.EA.GOVT.NZ)

For the other sectors, however, it was difficult to quantify and scale up based on the provided retailer data alone since each sectoral demand curve is an aggregation of different commercial and industrial ICPs for each respective region. This will be treated as an aggregated unallocated demand quantified as the difference between the regional half hourly EMI demand data and the collated aggregated regional demand from the retailers.

At this point, approximately 27 % of annual demand remains "Unallocated", i.e. 27% of the demand present in the EMI data is not accounted for by the retailer data after the direct connect industrial loads are considered.

Figure 2 Weekly demand by sector aggregation 2023 calendar year



Demand End Use Splitting and DR-Path Input File Writing

The objective for this step of data processing is to allocate the per interval sectoral demand into end use blocks. For the method, we reference EECA's Energy End Use Database[3] to determine the allocation at an end use level for each sector aggregation regionally. 0 shows sample week 25

[3] https://www.eeca.govt.nz/insights/data-tools/energy-end-use-database/

aggregated sectors end use split demand profiles. Note than unallocated demand features no end use splits due to lack of information on any classifier for the raw data.

This last step for data processing is to write the CSV files for each sector per region. The code is programmed to either locate or create an output folder in the code directory where the CSV files will be saved as shown in

7. Demand-side flexibility modelling

7.1. Overview of Modelling Approach

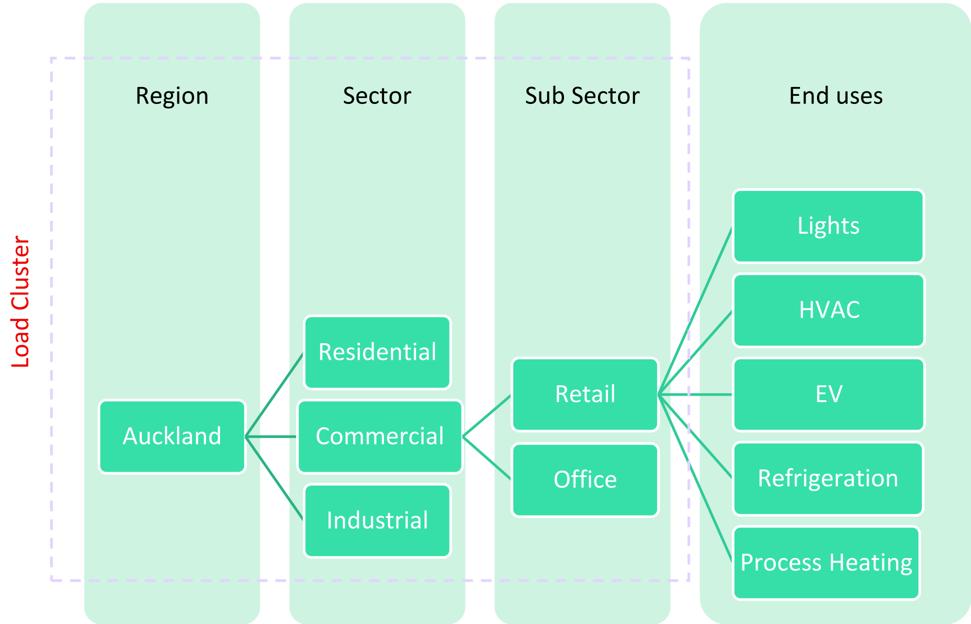
The New Zealand DSF model used in this study is a variation of the DR-path model developed for *The Californian Demand Response Potential Study, Phase 3*. The approach in the original model has been customised for the New Zealand national market. The methodology for calculating the national demand-side flexibility signal follows the original DR-path model; however, this version also generates an estimated dispatch profile at the end-use level for each of the load cluster. The model then uses this estimated dispatch profile to derive installed capacity and energy outputs based on a cost framework and technical constraints.

Further, the definition for the load clusters is different compared to the original DSF model. The original model focuses on detailed modelling for single region - where as our modified version focuses on using the national demand profile to estimates the demand side flexibility

Hence the model estimates demand-side flexibility based on clusters of pre-determined load profiles using total national level demand to construct a governing DSF signal. The net load profile for New Zealand is derived by a bottom-up approach that uses load profiles specific to multiple end-uses in different consumer clusters. A DSF filter is derived from the demand-side flexibility signal, and this filter is used to estimate the available DSF potential for each end-uses in load clusters.

A load cluster is defined as a unique combination of various subsectors (office space, metal industry etc.) with in a broader high-level categorisation which are industrial, commercial, and residential consumers which at a higher level is further classified based on regions.

Figure 3 Demand classification hierarchy



The current version of the model makes use of 165 load clusters. The modelling approach can be broken down into the following high-level steps:

1. Deriving a national level DSF signal for estimating shift and shed potential
2. Calculation of DSF features to be used in cost estimation
3. Costing framework to assess the economic viability of DSF potential

7.2. National level DSF Signals

The model aggregates the end-use level load profiles to a gross national demand. The net national demand that is used for calculating the DSF potential is then derived by taking out the renewable generation from the gross national demand. The renewable generation is the total generation from Wind, Solar and Geothermal.

$$Net\ load = Gross\ Load - Renewable\ Generation$$

Calculation of Shed potential and shed filter

The shed calculation is based on the top 250 hours of peak load in the net national-level load shape. The highest load gets highest weight and shed probabilities in each of these intervals are calculated as, Shed DSF filter, Si = (1/weight)/∑ (1/weights)

Here, weight is based on the rank of the total net load, i.e., the annual peak net load has the higher rank. This approach effectively selects the portion of the national load profile where cheaper and cleaner non-dispatchable forms of energy (i.e., wind and solar) have the lowest contribution in addressing possible high demand periods. Hence, the relative value tapping into DSF resource is higher during these intervals because a larger volume of flexible resource is needed to meet demand. The shed filter applied to the individual load profiles calculates a MW value based on the available demand-side flexibility against each of the end uses within a load cluster.

The MW Shed response within an interval is the product of the shed filter and the available load within the end use.

$$Shed\ DR\ Potential, DR_{raw} = S_i \times L_i$$

Where Li is load for interval – i.

Calculation of Shift Potential and Shift Filter

The first step in shift calculation is to derive a shift dispatch which is the difference between the rolling average of the net load and the net load for each interval.

$$Shift\ Dispatch = Rolling\ Average - Net\ Load$$

The shift dispatch can be interpreted as the total increase or decrease in load that is required to smoothen out the net load with respect to a rolling average of the demand.

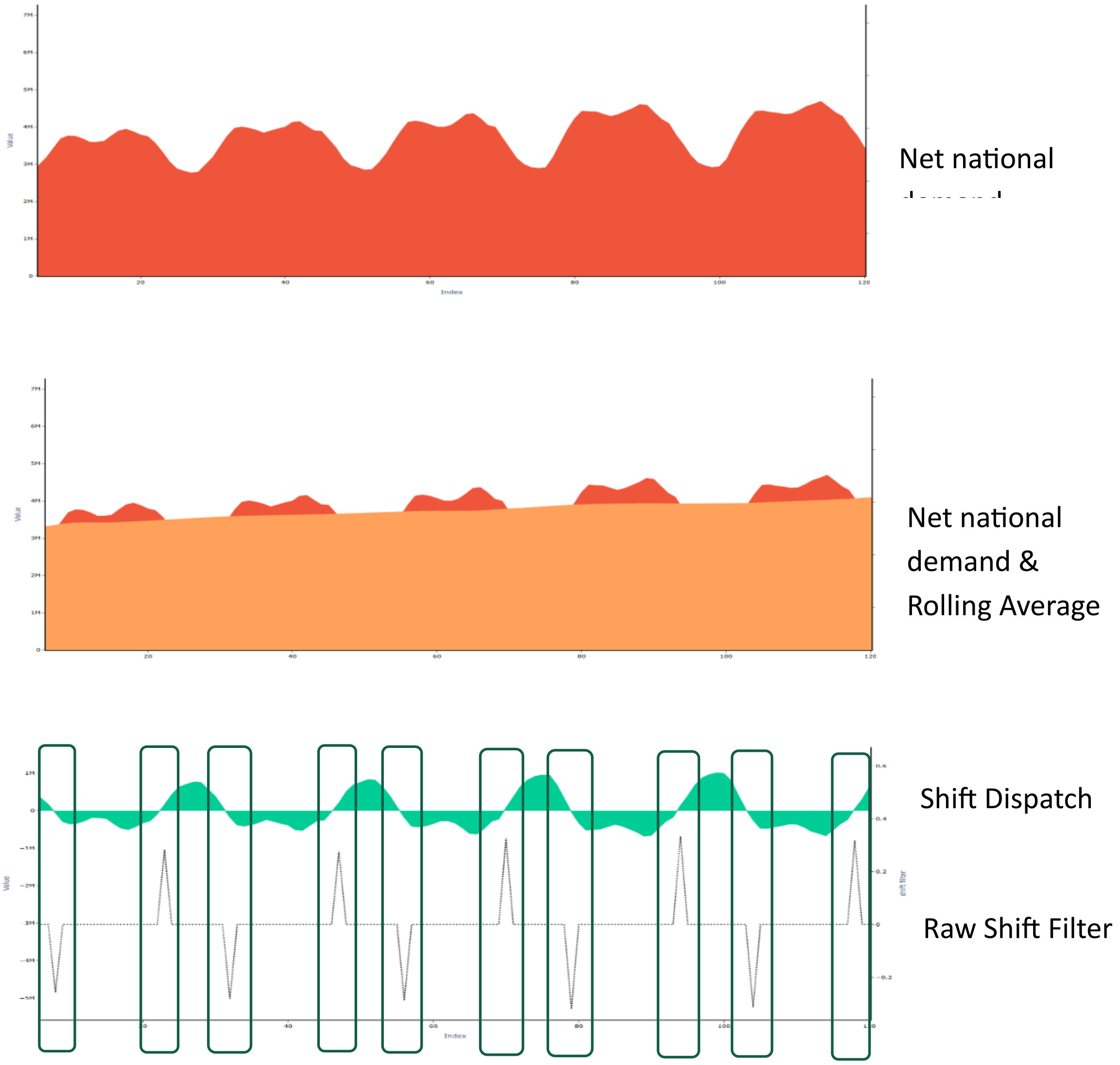
However, to derive a shift, we would need to ensure that load that is reduced during a specific set of intervals are balanced out by an equivalent volume of take backs. To achieve this, the model uses a "centering" logic which identifies pivot intervals around which adjacent sheds and takes are feasible. The algorithm looks for zero crossings in the shift dispatch within a user-specified rolling dispatch window and identifies the crossing point as the pivot interval.

Then the algorithm calculates the difference between the minimum and maximum shift dispatch around the pivot interval. This difference (as a ratio of rolling peak) is treated as the raw DSF filter by the model. If the algorithm cannot find a zero crossing within a rolling dispatch window, the model assigns a zero value to the raw DSF filter (i.e., DSF potential during that specific rolling window is zero). Hence for a pivot interval-i in rolling window with a zero crossing,

$$Raw\ Shift\ DR\ Filter, RF_i\ = \frac{(Max\ shift\ dispatch_i - Min\ shift\ dispatch_i)}{Rolling\ Peak_i}$$

The sign of the filter captures the parity of the shift window. The filter is positive if the last element in the window has a positive sign and negative if the last shift dispatch element is negative. The positive sign indicates a potential backward shift and negative sign a forward shift. However, the direction of shift further gets modified at end use level based shape of the load, prices and other dispatch constraints. Figure 4 is representation of the raw shift filter calculation in the model for 120 hours.

Figure 4 Construction shift filter



This raw filter is applied as it is to the shift potential load profile for each of the end uses to estimate the max DSF potential. In this case, the model assumes an equal probability for all the end uses to respond with an available demand-side flexibility based on the national level signals.

The following steps summarize the estimation of the shift potential for each of the end-use loads:

Calculation of the take cap: The take cap is the maximum limit on the increase in load for a specific end-use within a load cluster. It is the difference between the maximum load and the actual load within a time interval. Hence this represents the additional load an end-use can accommodate when a shift DSF operation is active. The take cap calculation also looks at the national level shift dispatch data and ensures that no take is possible during a potential shed period.

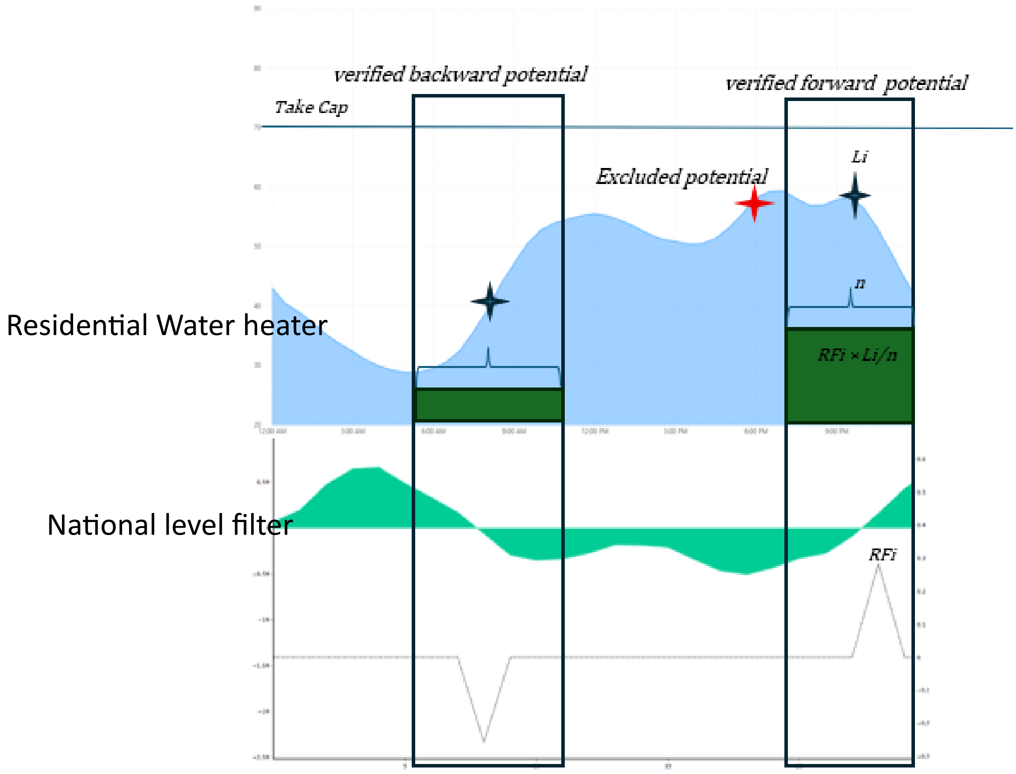
Assessing forward and backward potential: The forward and backward potential within an end use is assessed by comparing the sum of energy in the first half of a rolling window with the energy in the second half. For forward potential, the shed potential in the end use (i.e. the end-use load during the shed period of the national shift dispatch) is used to calculate the energy in the first half of the rolling window as potential shift. The take cap is then used to calculate the energy in the second half to determine whether the shed can be accommodated. For backward potential, the same logic is applied in reverse - the take cap is used in the first half, and the shed potential is assessed in the second half.

Shift Potential: The raw shift filter is then used to finalize the forward and backward potential. The forward potential in end-use that aligns with a positive shift filter is carried forward and multiplied by the factors in the shift filter. Similarly, the backward potential that aligns with the negative filter is carried forward as backward potential and multiplied by the absolute value of the corresponding factors.

$$Estimated\ DR\ Potential\ for\ interval\ i, DR_{raw} = RF_i \times L_i$$

Where RF_i is the absolute value of the filter that aligns with a verified forward or backward potential L_i in an end-uses for an interval i. The following figures shows the calculation of take cap, forward and backward potential and calculation of the shift potential at an end use level (residential water heater).

Figure 5 Forward and backward potential calculation



7.3. DR Feature Calculation

The calculation of the shed DSF feature is straightforward and does not require further processing. A fixed number of windows are identified based on the energy that is shifted with in those windows at a load cluster level. Then the highest MW values of shift within those are taken as megawatt (MW) of installed capacity for the economic assessment. The energy shed during these DSF windows is then used for revenue estimation.

However, the calculation of DSF features for shift demand-side flexibility is based on an estimated dispatch, which is modelled against the shift potential derived from the previous steps. And based on this shift dispatch one of the key features is the maximum DSF resource that a load cluster–end use combination can deliver (similar to shed-demand-side flexibility). A shift cycle consists of both shed and take operations. Hence for shift DR, this refers to the maximum shed or take operation in MW during any DSF window within a shift cycle for given target hours.

The second DSF feature—total energy—is calculated based on target hours for shift DSF potential for each end use. These targeted DSF hours are defined according to the technical or operational limitations specific to each load cluster–end use combination. We have set this value to 800 for the modelling undertaken for this paper, but this could be any value determined more appropriate for future work. Further the target hours are selected from a set of top, median and 75th percentile hours which are ranked in terms of the energy contained in the shift-cycles to create three different scenarios of shift-demand-side flexibility.

The first step in creating an estimated shift dispatch is to distribute the shed and take operations across the DSF window in a way that maximizes net market revenue. The second step involves applying corrections to the shift and take cycle based on a defined set of dispatch constraints.

Price Based dispatch

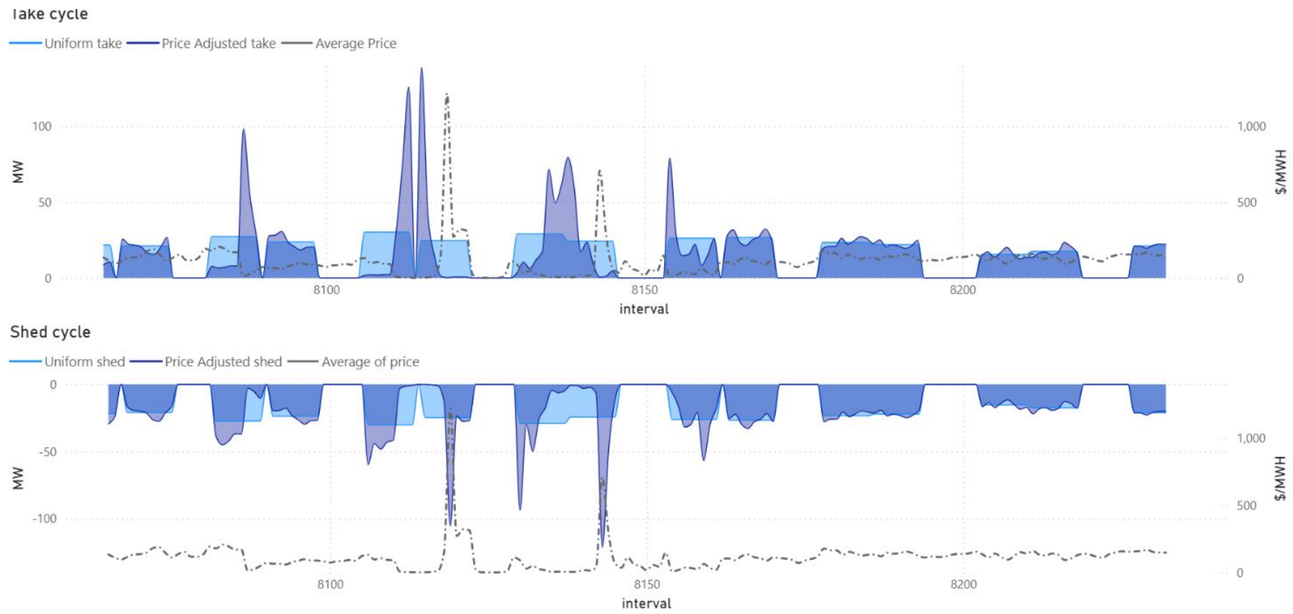
The shed and take operations are redistributed based on price signals derived from the shift potential identified in earlier steps. The price signal used is the average national price, and the redistribution of the shed/take cycle occurs at the end-use level. Price signals are used to rank dispatch intervals, guiding how energy is redistributed for shed or take operations.

Shed operations are prioritized during high-price periods, with weights assigned based on the ratio of the price in each interval to the sum of prices across the dispatch window. Conversely, take operations are prioritized during low-price intervals, using an inverse ratio of the interval price to the total price in the dispatch window to assign higher weights to low intervals with lower prices.

A purely price-based shed/take cycle can result in more pronounced peaks in shed or take operations, which is less representative of real-world shift demand-side flexibility. Note that this is not a dispatch model so it cannot see the impact of shifting on prices. As a result, relying solely on price logic can lead to unrealistic scenarios where the entire load in an end use during a high-price period is shifted to a low-price interval—resulting in a shift operation with 100% shed and 100% take relative to the original load profile.

The snippet of shift dispatch (for Auckland - residential water heater) shows the shed/take (in dark blue) operation that has concentrated sheds or take MW values in a single interval driven by the spike or fall in price. Note that, at this stage of the algorithm, DSF response is not constrained by device capacity or the cost of implementation, which is applied in a subsequent phase.

Figure 6 Impact of price adjustment on Auckland residential hot water load-shifting



Dispatch Constraints

There are dispatch constraints available in the model for both the shed and take operation as a provision to model the outputs closer to the real-world outcome.

Shed Constraint

The shed constraint defines a base load for each end use, which determines the amount of load that can be shed. The default assumption is a 50% base load; however, this is a user-defined input and can be adjusted on a case-by-case basis. If a shed operation exceeds the base load threshold, it is curtailed, and the corresponding take MWs within the same DSF window are reduced to compensate for the curtailed shed MWs. The reduction in take proportional to the same take profile derived from the price logic—meaning intervals with higher take values experience greater reductions. This approach helps minimize sign reversals in the take profile, which can occur when the adjustment at the interval level exceeds the total take for that interval.

However, applying shed constraints may result in a few negative take or positive shed intervals. These intervals are reset to zero, and the negative takes or positive sheds values are uniformly adjusted across the take/shed intervals in the DSF window that exceed the respective mean values.

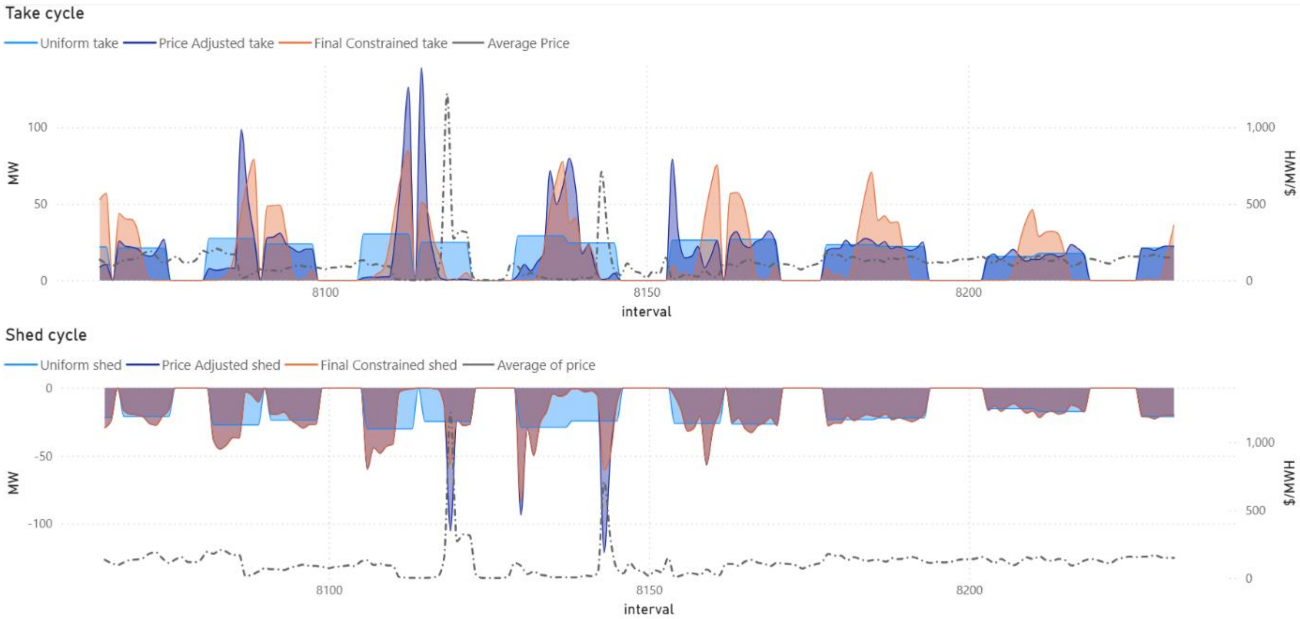
Take Constraint

The take operation is benchmarked against the rolling mean of the end-use load profile. The constraint algorithm adjusts the take such that the resulting net load profile aligns more closely with the rolling mean from the original load-shape for the end-use. Specifically, any load above the rolling mean is curtailed, and the difference is uniformly redistributed across the remaining take intervals within the DSF window. The moving window used to calculate the rolling mean is the same as that used for deriving the national-level rolling mean, which in turn informs the raw shift filter.

This adjustment is performed using a smoothing algorithm that sequentially calculates the difference between the adjusted take load and the rolling mean, modifies the take to align with the mean, and then redistributes the curtailed take across the remaining intervals. Due to the sequential nature of the algorithm, previously adjusted intervals may be re-edited as subsequent intervals are processed. This issue can be mitigated by applying multiple pass-throughs of the smoothing algorithm. By default, the model performs two smoothing passes, although this is a user-defined input and can be customized.

This figure below shows the shed/take operation (for Auckland - residential water heater) after price adjustment and after the application of the shift dispatch constraints explained above. A uniformly distributed shift and shed profile along with price signal are also included in figure for comparison

Figure 7 Impact of shift dispatch constraints of Auckland residential hot water load-shifting



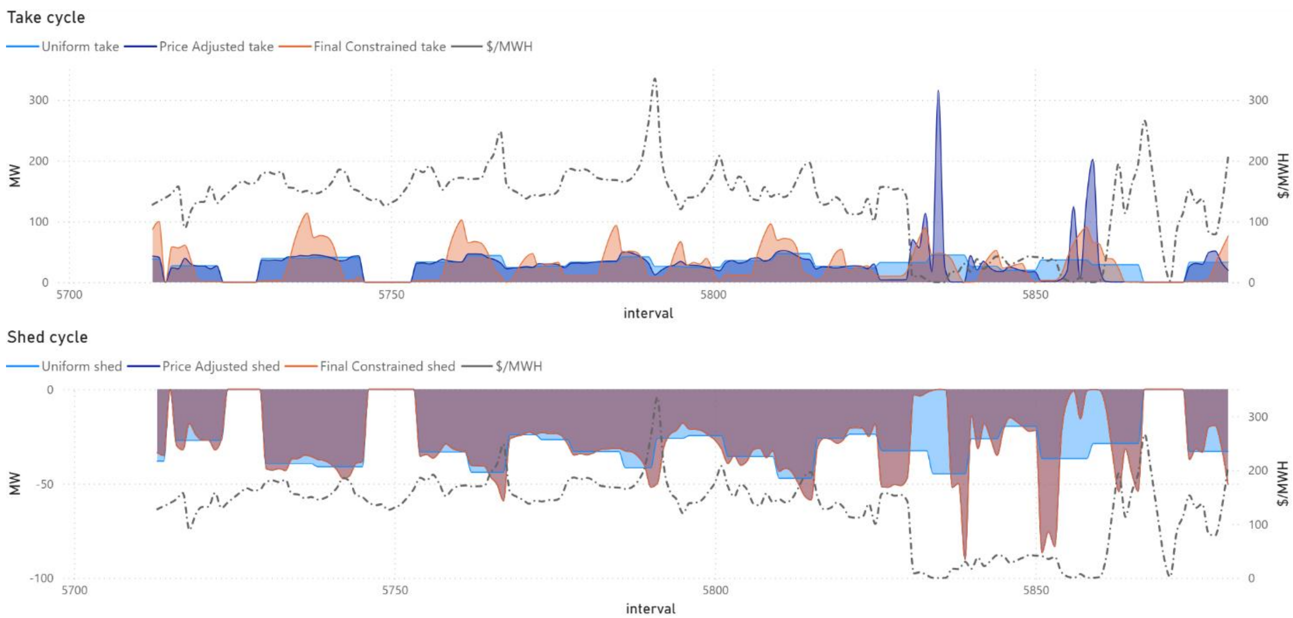
Overlapping DSF Windows

The model assumes the position of the shift filter as the center of a DSF window for estimating the shift dispatch profile. This assumption can, at times, result in overlapping DSF windows. For example, the model may generate three 8-hour shift operations, which—due to overlapping—could produce windows of 6, 7, and 8 hours. This overlap can lead to discrepancies in the total energy captured during shed and take operations. These discrepancies are driven by asymmetries in shed and take operations caused by price-based redistribution and dispatch constraints, as previously explained.

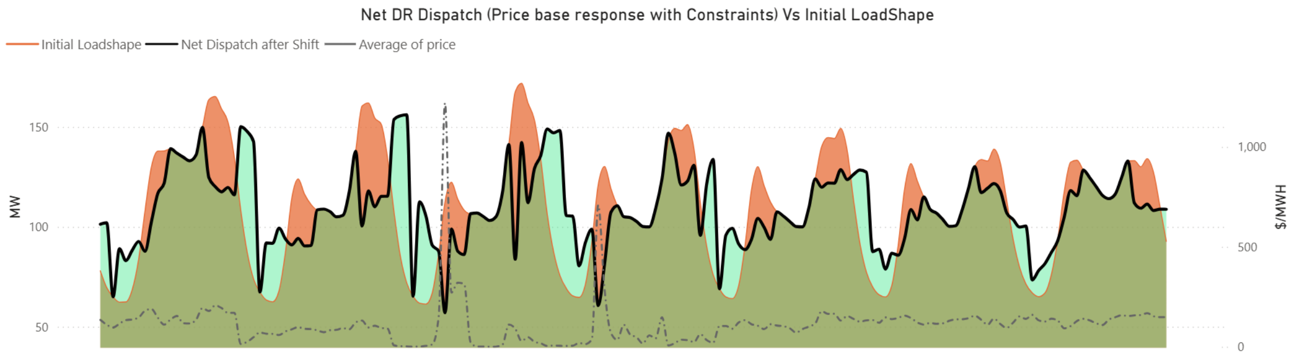
To address this issue, an additional correction algorithm is applied. This algorithm identifies the energy imbalance and adjusts the take operation to match the energy captured during the shed operation. The duration of each DSF window is preserved—meaning the 6-hour and 7-hour windows in the earlier example remain unchanged. As a result, the model may generate smaller DSF windows than the minimum defined duration due to multiple overlapping windows.

The accompanying figure illustrates an example of an overlapping cluster of shorter-duration shift DSF windows, generated despite a minimum defined duration of 8 hours.

Figure 8 Example of overlapping shift windows



The figure below shows a snippet of the initial load profile for Auckland - residential water heater end-use (red) and the net load profile after shift demand-side flexibility (green). It illustrates the shift of load from the original peak period (red area) to the off-peak period of the original load shape (light green area). The national average price signal is also provided in the figure for reference.



It is important to note that in this example, the end-use load profile aligns well with the national DSF signal—this is typically the case in some of the residential end uses. However, there are scenarios where load profiles do not align with the DSF signal generated at the national level, this can be observed in certain industrial end-uses.

Finally, the DSF features generated from the estimated shift dispatch are combined with additional inputs such as customer counts, technology and performance characteristics, uptake probabilities, dispatch-weighted prices, and other elements of the cost calculation framework in subsequent steps.

7.4. Cost Framework and Economic assessment

The model estimates various levels of costs termed as net procurement price, which is represented mainly in $/MWh. The cost associated with achieving DSF is calculated based on DSF technology which are matched to specific end uses within load clusters. Hence, each of the end uses within a load cluster can have multiple technologies which each has its own features such as uptake cap, limits in hours of DSF etc. Different costs-related inputs used in the model are as follows:

Table 3 Cost framework parameters

Cost Input framework	Description
Fixed Initial Capital Cost, FC	This covers the installation cost per site and is calculated based on the customer count (CC) after applying the uptake cap.
Variable Initial Capital Cost, VC	This input is a cost per kWp and is calculated based on the max available DSF in kW against an end use or in some cases for a load cluster.

Capital Recovery Factor, f	The capital recovery factor is used to derive an annualized figure from total capital cost. The total capital cost is the sum of the fixed and variable capital cost.
Fixed Operating Cost, FO	This is the annual fixed cost of operating a technology, hence a fixed value per consumer for a technology. This is calculated based on the customer count after applying the uptake cap.
Variable Operating Cost, VO	Variable operating cost varies with the load that is being enabled. For simplicity, we are estimating this based on the maximum load that can be enabled against an end use.
Co-benefit Ratio, CR	This represents the financial value of non-market benefits from the DR. Examples of such co-benefits are energy savings from the use of more efficient space heating or lighting, monetization of better consumer satisfaction in commercial spaces, improvement in energy efficiency, health benefits from improved residential heating, etc. This is captured as factor of the annual capital and operating cost.
Uptake Cap, UC	This is a cap on the uptake of certain technologies based on socio-economic, market, or technical constraints. Examples of such constraints can be low household income, constraints in residential DSF in units/apartments or for renters, technical issues in implementing DSF systems, DSF systems being less viable for certain consumers due to lower revenue from the market, etc.
Status	This is the tag in the model to differentiate between existing DSF installations and new DSF the model needs to build.
End use constraint factor, LF	This is a placeholder that can be used to exclude certain portions of the DSF against specific end uses through reduction factors. For example, a certain portion of the available DSF for residential heating can be taken out to account for inflexible demand during certain seasons.
Loss, LT	This is a placeholder for technical limitations for certain technologies such as high losses, lower efficiency, etc.
Technical Limit, TL or N	Targeted hours of shift potential that can be expected in a technology end use combination

Customer Count, CC	The customer count within a cluster is mainly used for estimating the fixed capital and operation cost

Assumptions used for economic assessment included in the model (e.g. capital cost aggregated to variable cost per KWp, co-benefits are excluded etc.) are based on the information available at the time and should be refined as economic and technical parameters change or are better understood.

Further, users can formulate a relationship between different inputs in the cost framework, for example - the uptake cap and incentive, i.e., uptake being higher at a higher incentive. This can be implemented by having multiple versions of the same technology end-use combination with different levels of uptake against different incentives.

7.5. Revenue estimations and Economic assessment

The revenue from shift demand-side flexibility is derived based on the estimated shift dispatch at the end-use level. The cost and savings from the demand-side flexibility in each end use are calculated for every DSF window. The savings are determined as the sum-product of the interval-level shed and the average national price.

$$Savings_{shift} = \sum L_{shed,i} \times P_i$$

Where $L_{shed,i}$ is the load shed during interval i of a DSF wind and Pi is the national price during that interval. Similarly, the cost is calculated as,

$$Cost_{shift} = \sum L_{take,i} \times P_i$$

Where $L_{take,i}$ is the load taken during interval i of DSF window to compensate for the shed

Finally, the market revenue is calculated as,

$$Market\ Revenue_{shift} = \ Savings_{shift} - \ Cost_{shift}$$

Market revenue is calculated for each DR-technology end-use combination (for each cluster load shape) evaluated in the economic assessment. Each technology has a target number of DSF hours which it can accommodate annually, and these target hours vary depending on the technology. Market revenue is calculated specifically against these defined target hours.

The model considers three scenarios when estimating market revenue: top, median, and bottom. The top scenario selects the top N DSF windows based on the energy contained in each window. By default, N = 800, although this is a user-defined input. During revenue estimation, the target hours for each technology–end-use combination are selected from the top N hours to maximize energy. Similarly, the median scenario uses the middle N hours, and the bottom scenario uses the lowest N hours—again selecting target hours to maximize energy within each scenario.

Procurement Price Calculation

Net procurement price is an indicator used to estimate the "missing money" or net cost (in $/MWh) required to facilitate specific levels of demand-side flexibility (DSF). The energy available in (MWh) at different net procurement price levels is used to generate a supply curve. Following is the mathematical representation of the cost calculation—based on the cost input framework—for each technology, to derive the net procurement price used in the supply curve.

$$Anualised\ Capital\ Cost = (DR_{Max\ end\ use} \times VC_{Tech} + FC_{tech} \times CC_{load\ cluster} \times UC_{tech}) \times f_{tech}$$

$$Anual\ Operating\ Cost = (Adjusted\ DR\ Potential_{KWH} \times VO_{Tech} + FO_{tech} \times CC_{load\ cluster} \times UC_{tech})$$

For shift demand-side flexibility $DR_{Max\ end\ use}$ and $Adjusted\ DR\ Potential_{KWH}$ are the maximum demand-side flexibility and energy captured in the target hours of shift dispatch for each scenario (top, median and bottom). Other input used for cost calculation include fixed and variable capital cost, uptake caps for technologies, capital recover factors along with annual operating cost the covers variable and fixed costs subjected to the uptake cap.

Finally, procurement price calculates as follows and is expressed as $/MWh values

$$Net\ Cost_{tech} = Anualised\ Capital\ Cost_{tech} + Anual\ Operating\ Cost_{tech} - Market\ Revenue_{tech} - Co\ benefit_{\ tech}$$

$$Net\ Procurement\ Price_{tech} = \frac{Net\ Cost_{tech}}{Adjusted\ DR\ Potential_{KWH}}$$

Where,

$$Co\ benefit_{\ tech} = (Anualised\ Capital\ Cost + Anual\ Operating\ Cost) \times CR_{tech}$$

The calculation includes placeholders for adding incentives, which essentially acts as a premium over the market revenue for energy captured through demand-side flexibility. Additionally, co-benefits are incorporated as an enhancement to revenue and are captured as a percentage-based reduction of the annualized capital and operating costs. These co-benefits reflect value derived from sources other than direct market revenue, such as improved energy efficiency, health benefits, or consumer satisfaction. Currently, co-benefit is expressed as a share of the technology costs that can be recovered from revenues or benefits outside the DSF function, but it could be easily re-formulated as an absolute value.

Supply Curve

The supply curve illustrates the energy delivered through demand flexibility from a combination of technologies available at different levels of net procurement price. The shed response is represented by a single supply curve, whereas the shift response includes three scenarios—top, median, and bottom—based on the energy available in each DSF window across N hours. Hence the supply curve for shift response presents a range for energy delivered at each procurement price level, helping to better capture the uncertainty associated with shift dispatch.

8. Modelling outcomes

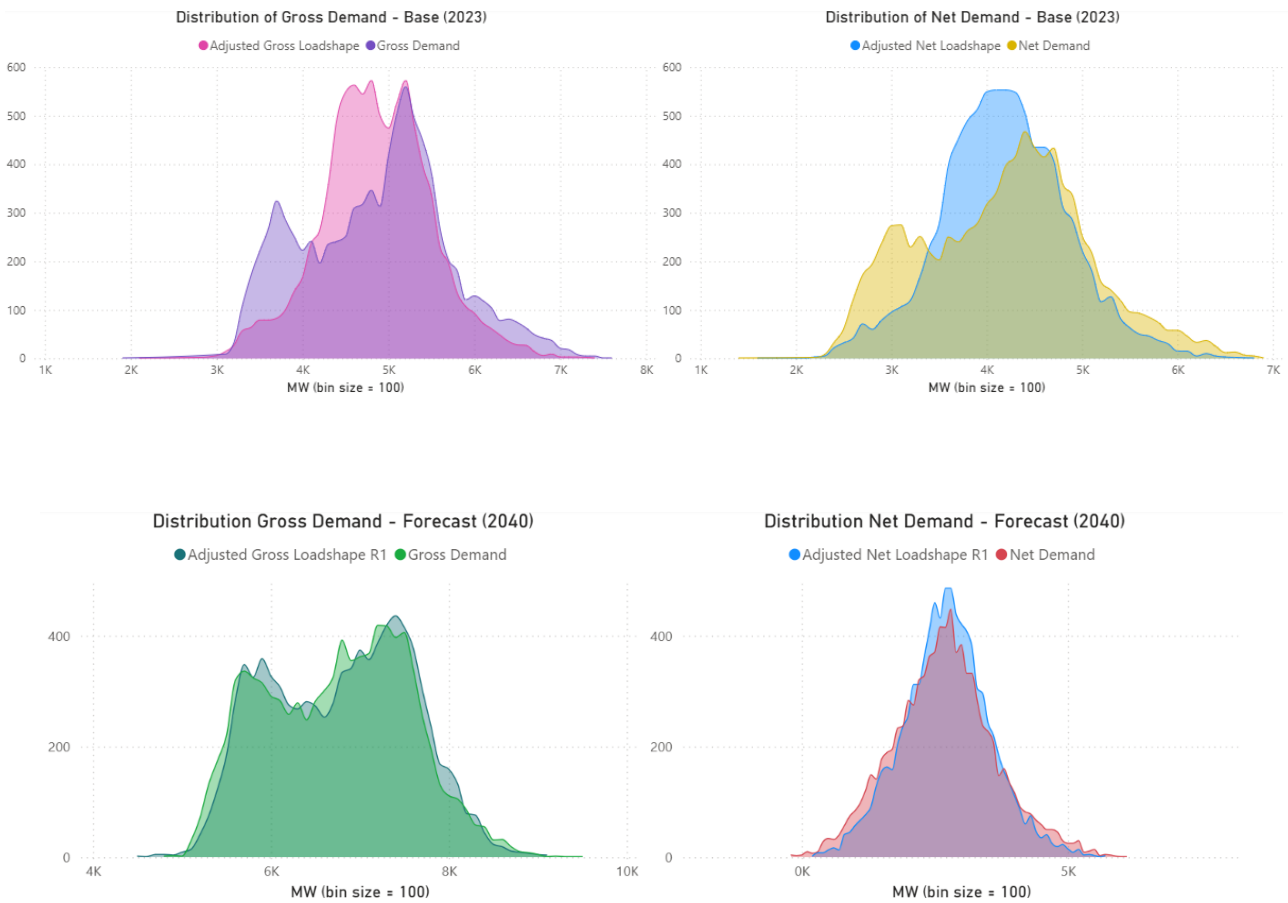
The distribution chart summarizes the impact of shift dispatch potential on the national net load. Shift demand-side flexibility redistributes the load into a more centred pattern ("Adjusted Gross Loadshape"), with most of the interval-level demand concentrated around the median demand in comparison to the higher spread in distribution seen in the original gross national demand. A more centred demand distribution translates to a demand time series that has fewer instances of extreme peak and off-peak fluctuation. This smoothing effect has important implications for grid stability and efficiency, potentially reducing the need for additional generation capacity and improving overall system reliability.

During the base year there is a significant reduction—approximately 50%—in the number of intervals with national net demand exceeding 6000 MW. In the original demand profile, 9.5% of intervals exceeded this threshold, whereas this dropped to 4.6% when the full shift potential was applied. This reduction is also evident from the denser tail of the gross demand distribution around peak intervals that become much thinner in distribution for "Adjusted Gross Loadshape" which has the demand flexibility. The impact on the RHS tail of the distribution (i.e. demand exceeding 6000 MW) remains the same across the Gross and Net demand distribution (adjusted for RE-generation) remains mostly the same, which indicates that DSF during those intervals target the real peaks that have lower renewable generations.

The key difference seen in the 2040 DSF forecast compared to 2023 DSF is that the shift demand-side flexibility predominantly moves peak demand to dispatch intervals with cheaper renewable energy. As a result, the model creates new peaks of gross load during the day, resulting in a similar distribution of gross load even after the demand-side flexibility. The remaining shift DSF (outside of the ones coinciding with RE generation) can be seen in net load distributions and they compress the resulting distribution, reducing the frequency of very high and low load periods. It is important to note that models do not consider inter-regional transmission constraints which can be a major limiting factor in achieving the modelled DSF potential in 2040.

It is important to note that this distribution assumes that all instances of 8-hour shift demand-side flexibility are available. However, for the purposes of the economic assessment, the assumption is that a total of 800 hours (roughly 100 instances of 8-hour shift DR) is available for each technology to choose from. The hours of DSF are further reduced as per each technology's technical limitations regarding the number of hours it can provide demand-side flexibility.

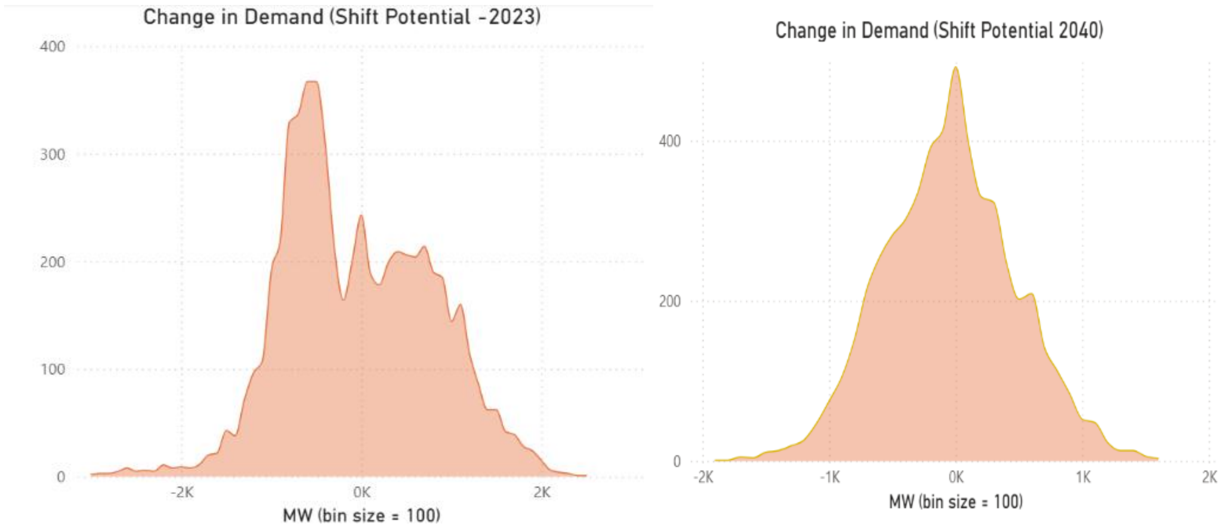
Figure 9 Impact of shift filter on loadshape (Distribution)



There are overlapping instances of shed and take operations both within and across different end-uses, this is due to various dispatch estimation logics and are driven by the varying load shapes of different end-uses, price-based dispatch of DSF, and shed/take constraints in the model. Although this is an artifact of the modelling methodology, it indirectly captures real-world inefficiencies and misalignments that can occur at the consumer level during demand-side flexibility. As a result, the net MW impact at the national level reflects the combined effect of these overlapping operations.

In figure 10, the national-level distribution of the change in demand for the 2023 base year shows that the majority of load reductions fall under 1,000 MW per interval, with most intervals concentrated around 400 MW to 800 MW. In contrast, intervals with a net increase in demand exhibit a more even spread between 100 MW and 1,000 MW. For the forecast year 2040, the distribution for both net reductions and increases in demand appear more centered.

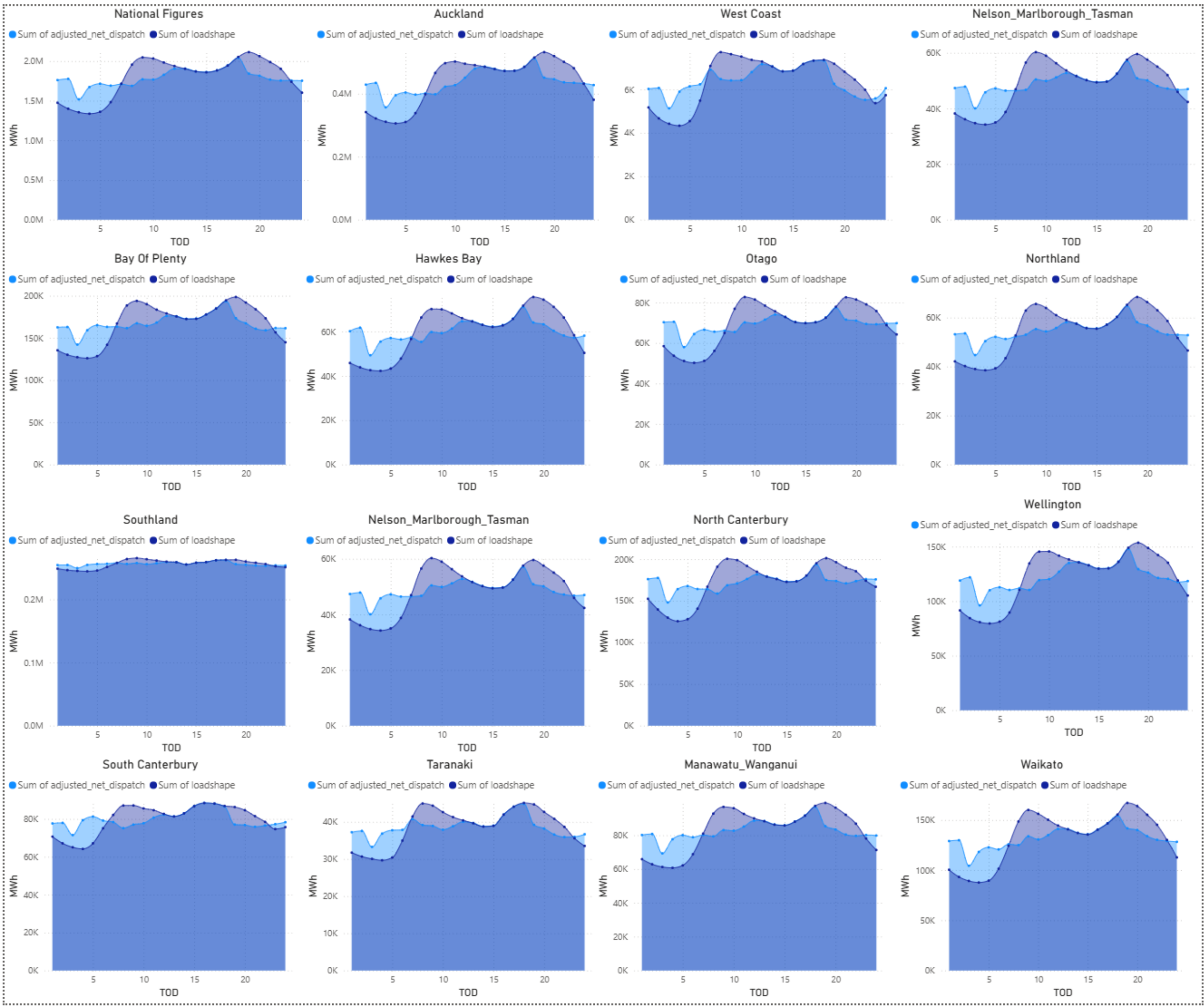
Figure 10 National shed and take distributions



The diurnal profile shown in Figure 11 compares the national-level DSF potential with that of each region. The chart illustrates the diurnal pattern by calculating the energy at each interval before and after the demand-side flexibility for the full DSF potential, highlighting the shift in energy across regions relative to the national profile.

Most regions show a reasonable level of alignment in terms of shifts in energy compared to the national profile, with Southland being the main exception due to its flatter load profile dominated by industrial demand. Additionally, DSF in regions such as West Coast, South Canterbury, and Taranaki is misaligned in the intervals that capture the highest quantum of energy. These regions are also characterized by a higher proportion of industrial demand.

Figure 11 Impact of shift filter on loadshape (Diurnal Energy Profile)



The economic assessment looks at the N=800 hours of demand-side flexibility to assess technologies at an end use level. The model looks at three separate categories for this,

1. Top 800 hour selected from the shift DSF window with highest captured energy
2. Probable DSF, with DSF window around 75th percentile of the captured energy
3. Median 800 hours which is centered around the median captured energy

The table presents the maximum interval-level shift demand-side flexibility in MW against the probable DSF (75th quantile), observed across various sub-sectors in each region. The figures represent the highest potential identified for each sub-sector, based on the sum of available DSF across all end uses during each interval.

Across all three scenarios, residential demand consistently shows the highest shift potential in many regions for base year 2023. However, there are notable exceptions. In South Canterbury, the farming industry exhibits the highest shift response across all scenarios. Similarly, in the Bay of Plenty, industries such as food processing and forestry products demonstrate greater peak shift response than the residential sub-sector.

In Southland, during base year 2023 the metals industry shows the highest peak shift response, particularly during DSF windows that capture the greatest amount of energy. However, actual feasibility in using this smelter demand and its flexibility needs to be explored further given the specific nature of this load and the interaction of short-term flex potential with demand-side flexibility contracts that operate on a longer-term basis.

The residential demand in Auckland, Wellington, Waikato, and North Canterbury consistently exhibit the highest national peak shift response. The trend is driven by the residential demand profile that has peaks which align with national level demand profile. As a result, DSF signal derived based on the national level profile maximizes the demand-side flexibility for residential sector. Also, in term of the peak shift potential, utilities and chemical consistently show a lower potential across all regions.

These tables do not include demand component that remain “unallocated” to any sub-sector under the industry sector (which covers the subsector such as chemical, farming, food processing, forestry product and metal) or the demand categorised as “other demand” in the commercial sector (which include both retail and office)

For the forecast year 2040, the maximum shift potential in the residential sector increases across most regions. A similar trend is observed in other subsectors, except for South Canterbury and North Canterbury Farming, which show a decline in the maximum shift response in the forecast year.

Table 4 Maximum Shift Response

Max shift response for 75th Quantile(2023)

region	chemicals	farming	food_processing	forestry_product	metals	office	res_misc	retail	utilities
Auckland	3.88	2.71	4.19	3.66	32.34	30.13	433.40	42.63	2.61
Bay Of Plenty	0.12	5.05	18.88	22.39	0.27	3.95	5.39	2.84	0.04
Gisborne	0.02	0.29	0.35	0.28	0.04	1.31	10.90	0.90	0.05
Hawkes Bay	0.09	3.64	3.77	0.70	1.09	4.25	84.86	2.96	0.17
Manawatu_Wanganui	0.30	8.71	2.35	10.56	0.38	6.51	52.65	5.93	0.08
Nelson_Marlborough_Tasman	0.08	3.04	0.94	4.64	0.19	3.39	47.16	3.53	0.06
North Canterbury	1.38	35.63	5.17	2.30	4.48	18.84	123.34	24.41	0.25
Northland	0.05	4.44	0.29	0.38	0.29	3.73	41.38	3.01	0.05
Otago	0.23	12.91	1.37	1.23	3.68	7.49	72.53	8.81	0.47
South Canterbury	0.15	125.12	3.12	0.46	0.49	3.12	19.51	3.94	0.15
Southland	0.83	20.93	8.26	0.79	19.09	2.74	28.24	3.01	0.11
Taranaki	0.62	9.84	0.34	0.65	4.40	2.67	26.11	2.03	2.15
Waikato	0.58	32.19	5.38	2.83	5.06	12.35	146.43	9.96	0.49
Wellington	0.56	2.89	1.77	0.95	1.03	16.48	172.29	16.83	0.20
West Coast	0.01	1.37	0.03	0.01	0.14	0.75	5.93	0.87	0.04

The supply curve below represents the energy output from DSF following the economic assessment. The x-axis shows the procurement price—i.e., the net gap in $/MWh that must be filled to access DSF energy. The model estimates 1,083 GWh of energy could be accessed at a procurement price of 500$ /MWh against the probable scenario (75th quantile) for the base year

Max shift response for 75th Quantile(2040)

region	chemicals	farming	food_processing	forestry_product	metals	office	res_misc	retail	utilities
Auckland	2.16	15.63	24.11	4.51	52.44	40.95	559.50	44.68	2.36
Bay Of Plenty	0.13	4.92	33.84	20.59	0.27	7.31	27.15	6.35	0.04
Gisborne	0.02	0.30	0.48	0.30	0.04	2.48	15.24	1.25	0.06
Hawkes Bay	0.09	4.02	3.37	0.72	0.87	5.83	101.75	3.30	0.17
Manawatu_Wanganui	0.29	9.83	31.22	12.69	0.44	13.76	71.10	6.32	0.09
Nelson_Marlborough_Tasman	0.08	3.54	1.01	5.79	0.25	5.07	60.36	4.64	0.09
North Canterbury	1.38	27.48	6.35	1.93	3.96	27.14	207.81	28.68	0.29
Northland	0.05	4.51	25.15	0.43	0.34	6.27	55.03	3.59	0.05
Otago	0.22	14.81	2.59	1.07	9.74	12.35	88.72	10.56	0.49
South Canterbury	0.16	85.20	33.22	0.38	0.48	12.46	25.47	4.82	0.18
Southland	0.54	22.23	51.29	0.51	26.20	5.50	34.85	3.66	0.15
Taranaki	0.88	11.83	39.15	0.63	3.31	4.10	36.85	2.75	2.17
Waikato	0.61	33.29	108.34	5.56	4.79	17.69	189.08	11.53	0.41
Wellington	0.63	3.71	1.55	1.16	0.94	21.49	212.99	16.71	0.24
West Coast	0.01	2.83	15.59	0.68	0.16	1.56	7.92	1.32	0.05

20. And of this, approximately 666 GWh is from residential load, 99 GWh from industrial load, and 317 GWh from commercial load. During the forecast year of 2040 the total energy at 500 $/MWh increases to 1431 GWh due to proportionate increase across the section with minimum increase seen for the commercial sector. These prices are comparable to the current operating cost of a diesel generator.

Figure 12 Demand-side flexibility supply curves 2023

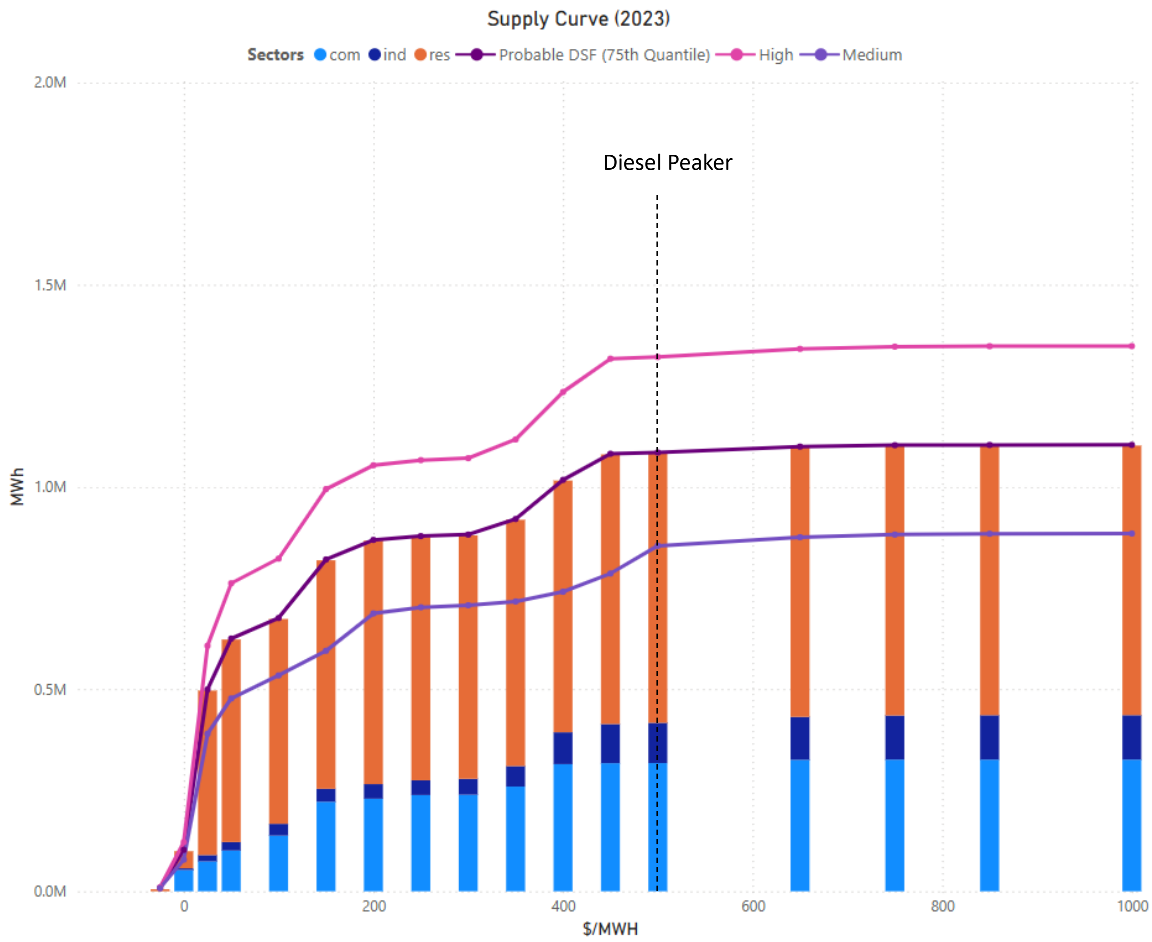
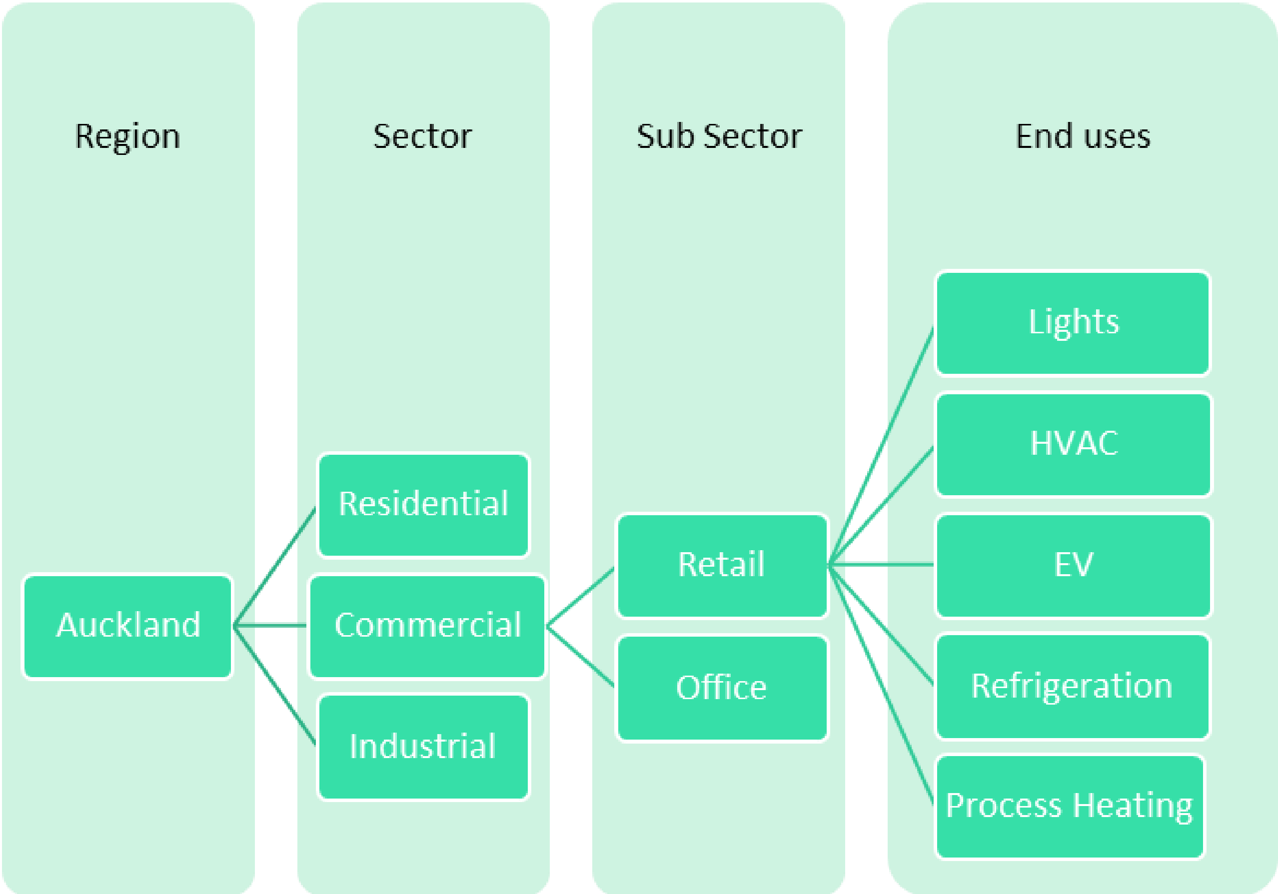


Figure 13 Demand-side flexibility supply curves 2040



The table show the percentage contribution of the energy access at $500/MWh under each of the three scenarios. Residential by far is the biggest contributor shift DSF followed by farming, retail and office when all "Unallocated & "other" demands are excluded from the mix. The contribution from food processing industry shows a considerable jump in 2040.

2023 - Contribution from sub sectors (excluding "unallocated" & "other")

building_type	High	Probable	Medium
chemicals	0.12%	0.10%	0.09%
farming	6.39%	5.54%	4.43%
food_processing	1.53%	1.51%	1.28%
forestry_product	0.77%	0.67%	0.57%
metals	1.00%	0.92%	0.78%
office	3.83%	3.98%	4.02%
res_misc	81.83%	82.48%	83.77%
retail	4.34%	4.62%	4.88%
utilities	0.20%	0.19%	0.18%
Total	**100.00%**	**100.00%**	**100.00%**

2040 - Contribution from sub sectors (excluding "unallocated" & "other")

building_type	High	Probable	Medium
chemicals	0.11%	0.10%	0.09%
farming	5.59%	5.13%	4.58%
food_processing	8.89%	8.22%	7.41%
forestry_product	1.04%	0.74%	0.78%
metals	1.55%	1.15%	1.16%
office	3.83%	3.55%	3.75%
res_misc	75.46%	77.74%	78.75%
retail	3.35%	3.21%	3.32%
utilities	0.18%	0.17%	0.16%
Total	**100.00%**	**100.00%**	**100.00%**

Table 5 Contribution of various sub sector towards DSF energy access at 500$/MWH

The default cost framework in the model assumes a 10% uptake cap for all newly installed technologies, which limits the installed DSF capacity and associated energy. It is important to note that uptake cap is specific to a technology, that is if multiple technologies are mapped to an end use, the uptake probability and energy captured in the supply curve adds up. Additionally, 5% of the potential is attributed to existing residential water heaters, which are assumed to have zero capital cost. The model also factors in a 10% energy loss during shift operations.

Further constraints apply to residential loads, specifically HVAC, lighting, and refrigeration. HVAC loads are assumed to be available for DSF only 50% of the time, lighting for 10%, and refrigeration is considered inflexible in the residential sector. These constraints reduce the energy available for market revenue estimation, thereby increasing the net procurement price.

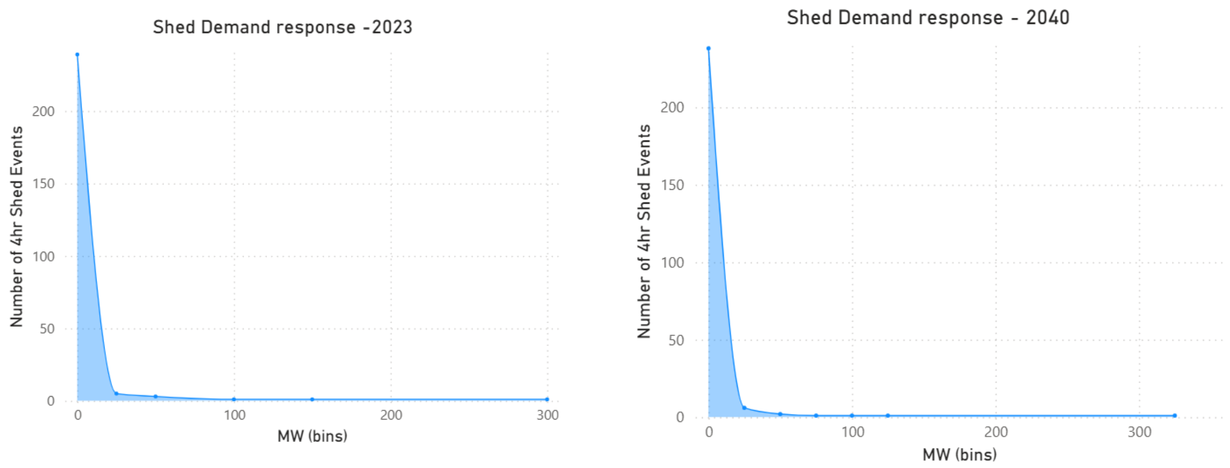
The battery technology considered for residential applications is a lower-cost option, with a capital cost of $2000 per kWp. Its energy capture capability is limited to 50% compared to more expensive commercial-scale batteries. This reduction reflects the impact of shorter-duration storage (e.g., a 2-hour battery), which may not be able to capture the full energy potential within an 8hour DSF window.

Capital costs in the model are captured as variable costs per kWp and are annualized using a capital recovery factor of 10%. The accompanying table maps sub-sectors, and their end uses to technology types (as used in the model), along with variable capital costs and assumptions regarding the number of hours each technology can provide shift DR. A full table of these inputs is available in the appendix of this report.

Estimate Standalone Shed Potential

The distribution chart below shows shed potential across 250 shed events, each assumed to be 4 hours in duration. These events are independent of the shift demand-side flexibility and are based on high-demand intervals at the national level. The estimated dispatch-weighted price across these events is $195/MWh. The maximum shed DSF is estimated at 313 MW when capacity is evenly shed across a 4-hour window. A shorter window, such as 2 hours, would result in a peakier maximum shed of approximately 626 MW. However, the economic cost of shed DSF should be carefully evaluated across various sub-sectors, considering opportunity costs and other losses. The estimated shed for 2040 remains mostly the same with maximum shed demand-side flexibility estimated at 338 MW and dispatch weighted price dropping to 190 $/MWH.

Figure 14 Shed demand reponse



9. Further work

This data collected and model developed during this work has added considerable value to the toolkit for examining demand-side flexibility, but the process also highlighted where there are gaps in the available data and unfinished business in the modelling of DSF.

9.1. Data gaps

Load data

Future DSF analysis would benefit greatly from a comprehensive and consistent high-resolution load dataset - particularly one that captures different end uses by sector.

There is limited data available at the half-hourly level to separate sectoral load into different end-uses. EECA's Energy End-use Database has provided valuable volumetric that has complemented the small amount of half-hourly end-use data that was available. However, future iterations of this work would benefit from a data-collection programme that samples a wide variety of sectors to determine the daily and seasonal profiles of their end uses as a share of the total electricity load.

Technology cost data

Establishment of a common dataset and monitoring of technology costs and constraints will add a lot of value to subsequent iterations of this modelling exercise. The "missing money" - or the gap between market revenue and the cost of DSF technology is sensitive to the technology cost assumptions, which would subsequently affect the magnitude of incentive required to accelerate DSF uptake.

9.2. Model development

Integration with market model

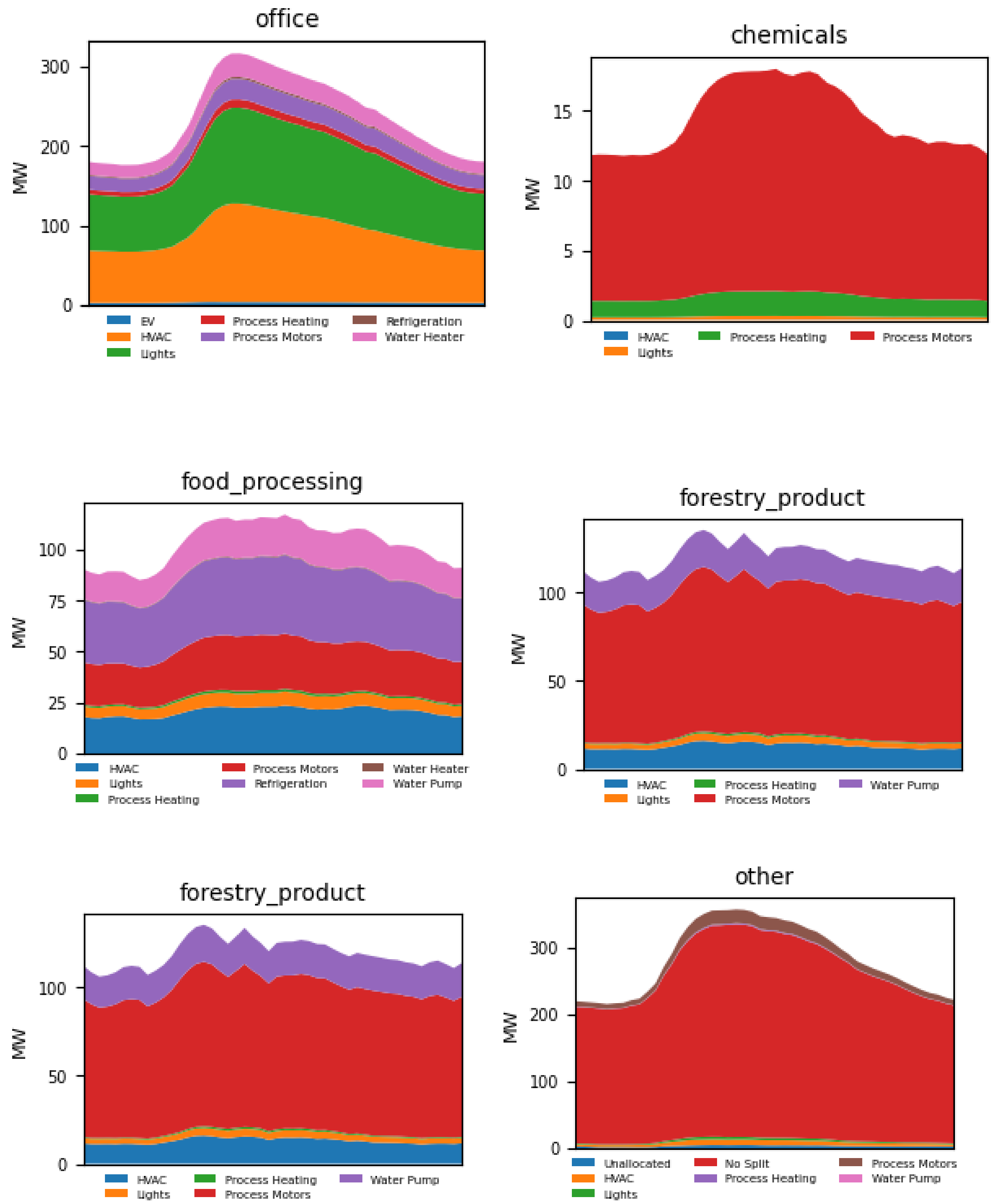
The DSF model is not a market dispatch model. While it takes market (or modelled) prices as input, it does not provide real insight on the impact of the DSF on spot prices or the subsequent dynamic impact of spot price changes on DSF dispatch.

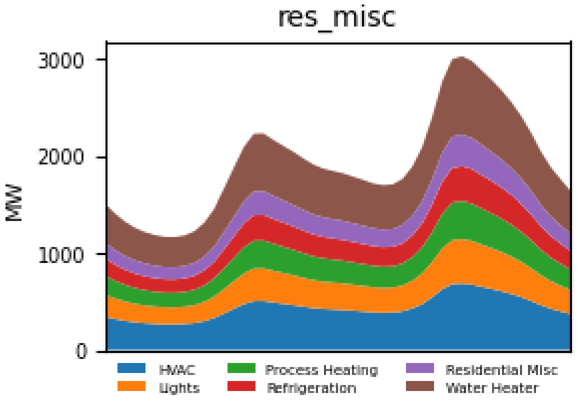
Integrating the outcomes of this work a market model capable of optimally dispatch the DSF potential subject to technology, market, and network constraints and determining the impact on price and economic capacity expansion would add considerable value to the work already undertaken.

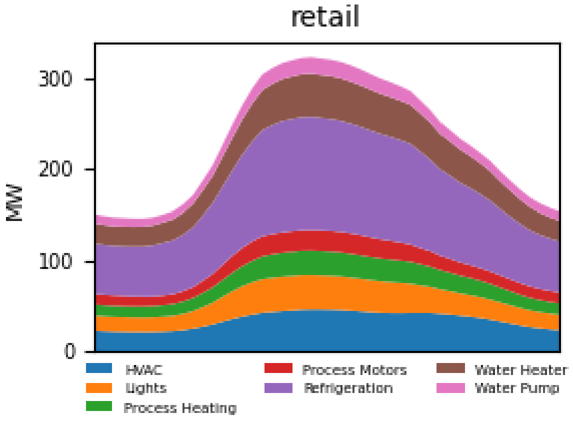
Regional iterations

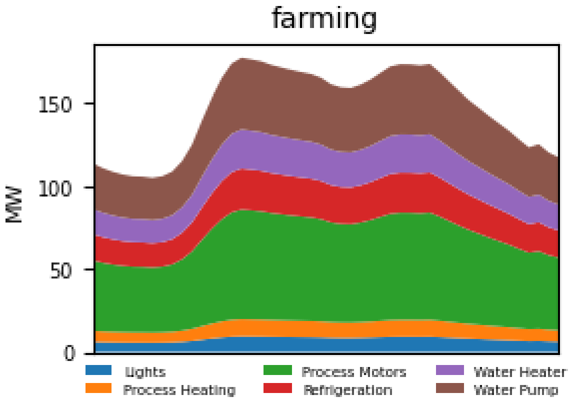
Work to date has focused on DSF responding to national shift signals, but additional work could be done to iteratively run the model for each region with the objective of the region responding to its own signal, i.e. minimising regional demand rather than contributing to the minimisation of national demand. This could provide insight into when regional and national signals align and when they do not and therefore the structure of interventions that would unlock the most DSF potential across the country.

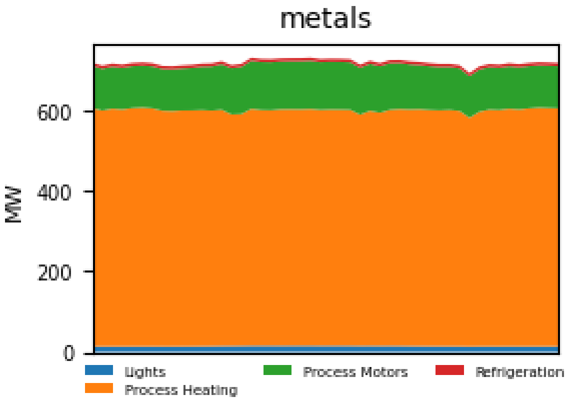
Week 25, 2023 sectoral average half-hourly diurnal end-use curves

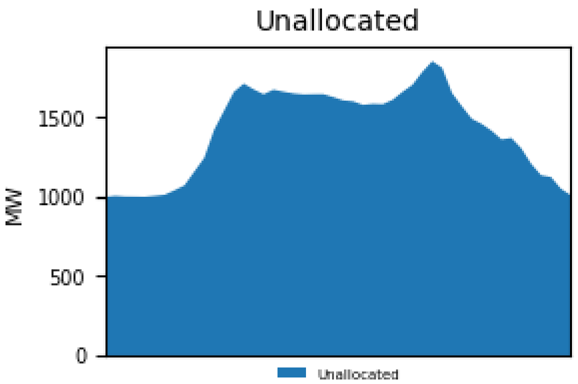


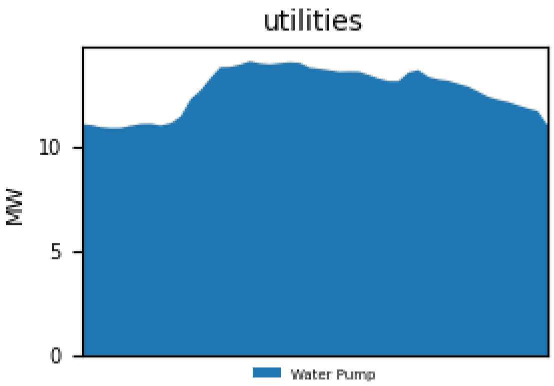

res_misc
MW
3000
2000
1000
0
HVAC
Lights
Process Heating
Refrigeration
Residential Misc
Water Heater


retail
MW
300
200
100
0
HVAC
Lights
Process Heating
Process Motors
Refrigeration
Water Heater
Water Pump


farming
MW
150
100
50
0
Lights
Process Heating
Process Motors
Refrigeration
Water Heater
Water Pump


metals
MW
600
400
200
0
Lights
Process Heating
Process Motors
Refrigeration


Unallocated
MW
1500
1000
500
0
Unallocated


utilities
MW
10
5
0
Water Pump

Sectoral classification and aggregation

General Aggregation	Sectoral Aggregation	Sector ID	Description
ind	farming	**1**	Agriculture, Forestry and Fishing
ind	metals	**2**	Mining
ind	food_processing	**3**	Meat and Meat Product Manufacturing and Seafood
ind	food_processing	**4**	Dairy Product Manufacturing
ind	food_processing	**5**	Food and Beverage Product Manufacturing (excluding Dairy, Meat, Seafood)
ind	other	**6**	Textile, Leather, Clothing and Footwear Manufacturing
ind	forestry_product	**7**	Wood Product Manufacturing
ind	forestry_product	**8**	Pulp, Paper and Converted Paper Product Manufacturing
ind	other	**9**	Printing (including the Reproduction of Recorded Media)
ind	chemicals	**10**	Petroleum, Basic Chemical and Rubber Product Manufacturing
ind	other	**11**	Non-Metallic Mineral Product Manufacturing
ind	metals	**12**	Primary Metal and Metal Product Manufacturing
ind	metals	**13**	Fabricated Metal Product, Transport Equipment, Machinery and Equipment Manufacturing
ind	forestry_product	**14**	Furniture and Other Manufacturing
ind	utilities	**15**	Electricity Supply
ind	utilities	**16**	Gas Supply
ind	utilities	**17**	Water Supply, Sewerage and Drainage Services
ind	utilities	**18**	Waste Collection, Treatment and Disposal Services
ind	other	**19**	Construction
com	retail	**20**	Wholesale Trade
com	retail	**21**	Retail Trade
com	retail	**22**	Accommodation and Food Services
com	office	**23**	Transport, Postal and Warehousing
com	office	**24**	Information Media and Telecommunications

com	office	**25**	Financial and Insurance Services
com	retail	**26**	Rental Hiring and Real Estate Services
com	retail	**27**	Professional, Scientific and Technical Services
com	office	**28**	Administrative and Support Services
com	office	**29**	Public Administration and Safety
com	office	**30**	Education and Training
com	office	**31**	Health Care and Social Assistance
com	office	**32**	Arts and Recreation Services
com	other	**33**	Other Services
res	res_misc	**99**	Residential
com	Unallocated	**9999**	Unallocated

Sub Sector	End Use	Technology Name	Variable Captial Cost KWp - 2023	Variable Capital Cost KWp - 2040
Unallocated	Unallocated	Commercial scale Battery	2000	1000
Unallocated	Unallocated	PV+Battery	4167	2500
Unallocated	Unallocated	Heat Pump controller	250	213
Unallocated	Unallocated	Hot Water controller	833	708
res_misc	Water Heater	PV+Battery	4167	2500
res_misc	Water Heater	Battery	2000	1000
res_misc	Water Heater	Hems	1500	1200
res_misc	Water Heater	Heat Pump controller	250	213
res_misc	Water Heater	Hot Water controller	833	708
res_misc	HVAC	Hems	1500	1200
res_misc	HVAC	Battery	2000	1000
res_misc	HVAC	PV+Battery	4167	2500
res_misc	HVAC	Heat Pump controller	250	213
metals	Process Heating	PV+Battery	4167	2500
metals	Process Heating	Commercial scale Battery	4000	2000
metals	Process Heating	Heat Pump controller	250	213
res_misc	Lights	Hems	1500	1200
res_misc	Lights	Battery	2000	1000

Sub Sector	End Use	Technology Name	Variable Captial Cost KWp - 2023	Variable Capital Cost KWp - 2040
res_misc	Lights	PV+Battery	4167	2500
res_misc	Process Heating	PV+Battery	4167	2500
res_misc	Process Heating	Hems	1500	1200
res_misc	Process Heating	Battery	2000	1000
res_misc	Process Heating	Heat Pump controller	250	213
res_misc	Refrigeration	PV+Battery	4167	2500
res_misc	Refrigeration	Battery	2000	1000
res_misc	Refrigeration	Hems	1500	1200
res_misc	Refrigeration	Heat Pump controller	250	213
res_misc	Residential Misc	Hems	1500	1200
res_misc	Residential Misc	Battery	2000	1000
res_misc	Residential Misc	PV+Battery	4167	2500
res_misc	Residential Misc	Heat Pump controller	250	213
res_misc	Residential Misc	Hot Water controller	833	708
farming	Process Motors	PV+Battery	4167	2500
farming	Process Motors	Commercial scale Battery	4000	2000
other	No Split	Commercial scale Battery	2000	1000
other	No Split	PV+Battery	4167	2500

Sub Sector	End Use	Technology Name	Variable Captial Cost KWp - 2023	Variable Capital Cost KWp - 2040
other	No Split	Hot Water controller	833	708
farming	Water Pump	PV+Battery	4167	2500
farming	Water Pump	Commercial scale Battery	4000	2000
farming	Water Pump	Timer Control (storage)	250	213
forestry_product	Process Motors	PV+Battery	4167	2500
forestry_product	Process Motors	Commercial scale Battery	4000	2000
retail	Refrigeration	Commercial scale Battery	2000	1000
retail	Refrigeration	PV+Battery	4167	2500
retail	Refrigeration	Heat Pump controller	250	213
farming	Refrigeration	Commercial scale Battery	4000	2000
farming	Refrigeration	PV+Battery	4167	2500
farming	Refrigeration	Heat Pump controller	250	213
farming	Water Heater	Commercial scale Battery	4000	2000
farming	Water Heater	PV+Battery	4167	2500
farming	Water Heater	Heat Pump controller	250	213
farming	Water Heater	Hot Water controller	833	708
office	HVAC	PV+Battery	4167	2500
office	HVAC	Commercial scale Battery	2000	1000

Sub Sector	End Use	Technology Name	Variable Captial Cost KWp - 2023	Variable Capital Cost KWp - 2040
office	HVAC	Heat Pump controller	250	213
office	Lights	Commercial scale Battery	2000	1000
office	Lights	PV+Battery	4167	2500
metals	Process Motors	PV+Battery	4167	2500
metals	Process Motors	Commercial scale Battery	4000	2000
farming	Process Heating	Commercial scale Battery	4000	2000
farming	Process Heating	PV+Battery	4167	2500
farming	Process Heating	Heat Pump controller	250	213
retail	Water Heater	Commercial scale Battery	2000	1000
retail	Water Heater	PV+Battery	4167	2500
retail	Water Heater	Heat Pump controller	250	213
retail	Water Heater	Hot Water controller	833	708
farming	Lights	PV+Battery	4167	2500
farming	Lights	Commercial scale Battery	2000	1000
food_processing	HVAC	Commercial scale Battery	4000	2000
food_processing	HVAC	PV+Battery	4167	2500
food_processing	HVAC	Heat Pump controller	250	213
retail	HVAC	PV+Battery	4167	2500

Sub Sector	End Use	Technology Name	Variable Captial Cost KWp - 2023	Variable Capital Cost KWp - 2040
retail	HVAC	Commercial scale Battery	2000	1000
retail	HVAC	Heat Pump controller	250	213
retail	Lights	Commercial scale Battery	2000	1000
retail	Lights	PV+Battery	4167	2500
utilities	Water Pump	PV+Battery	4167	2500
utilities	Water Pump	Commercial scale Battery	4000	2000
utilities	Water Pump	Timer Control (storage)	250	213
forestry_product	Water Pump	PV+Battery	4167	2500
forestry_product	Water Pump	Commercial scale Battery	4000	2000
forestry_product	Water Pump	Timer Control (storage)	250	213
food_processing	Water Pump	PV+Battery	4167	2500
food_processing	Water Pump	Commercial scale Battery	4000	2000
food_processing	Water Pump	Timer Control (storage)	250	213
retail	Process Motors	Commercial scale Battery	2000	1000
retail	Process Motors	PV+Battery	4167	2500
food_processing	Refrigeration	PV+Battery	4167	2500
food_processing	Refrigeration	Commercial scale Battery	4000	2000
food_processing	Refrigeration	Heat Pump controller	250	213

Sub Sector	End Use	Technology Name	Variable Captial Cost KWp - 2023	Variable Capital Cost KWp - 2040
retail	Water Pump	Commercial scale Battery	2000	1000
retail	Water Pump	PV+Battery	4167	2500
retail	Water Pump	Timer Control (storage)	250	213
retail	Process Heating	Commercial scale Battery	2000	1000
retail	Process Heating	PV+Battery	4167	2500
retail	Process Heating	Heat Pump controller	250	213
office	Water Heater	PV+Battery	4167	2500
office	Water Heater	Commercial scale Battery	2000	1000
office	Water Heater	Heat Pump controller	250	213
office	Water Heater	Hot Water controller	833	708
other	Process Motors	Commercial scale Battery	4000	2000
other	Process Motors	PV+Battery	4167	2500
chemicals	Process Motors	Commercial scale Battery	4000	2000
chemicals	Process Motors	PV+Battery	4167	2500
office	Process Motors	PV+Battery	4167	2500
office	Process Motors	Commercial scale Battery	2000	1000
forestry_product	HVAC	Commercial scale Battery	4000	2000
forestry_product	HVAC	PV+Battery	4167	2500

Sub Sector	End Use	Technology Name	Variable Captial Cost KWp - 2023	Variable Capital Cost KWp - 2040
forestry_product	HVAC	Heat Pump controller	250	213
food_processing	Process Motors	PV+Battery	4167	2500
food_processing	Process Motors	Commercial scale Battery	4000	2000
metals	Lights	Commercial scale Battery	2000	1000
metals	Lights	PV+Battery	4167	2500
other	HVAC	Heat Pump controller	250	213
other	HVAC	Commercial scale Battery	4000	2000
other	HVAC	PV+Battery	4167	2500
office	Process Heating	Commercial scale Battery	2000	1000
office	Process Heating	PV+Battery	4167	2500
office	Process Heating	Heat Pump controller	250	213
metals	Refrigeration	Commercial scale Battery	4000	2000
metals	Refrigeration	PV+Battery	4167	2500
metals	Refrigeration	Heat Pump controller	250	213
other	Unallocated	Commercial scale Battery	4000	2000
other	Unallocated	PV+Battery	4167	2500
other	Unallocated	Heat Pump controller	250	213
other	Unallocated	Hot Water controller	833	708

Sub Sector	End Use	Technology Name	Variable Captial Cost KWp - 2023	Variable Capital Cost KWp - 2040
food_processing	Lights	PV+Battery	4167	2500
food_processing	Lights	Commercial scale Battery	2000	1000
other	Lights	PV+Battery	4167	2500
other	Lights	Commercial scale Battery	2000	1000
forestry_product	Lights	PV+Battery	4167	2500
forestry_product	Lights	Commercial scale Battery	2000	1000
office	EV	EV charger public	4000	3000
chemicals	Process Heating	Commercial scale Battery	4000	2000
chemicals	Process Heating	PV+Battery	4167	2500
office	Refrigeration	Commercial scale Battery	2000	1000
office	Refrigeration	PV+Battery	4167	2500
office	Refrigeration	Heat Pump controller	250	213
other	Process Heating	Commercial scale Battery	4000	2000
other	Process Heating	PV+Battery	4167	2500
other	Process Heating	Heat Pump controller	250	213
food_processing	Process Heating	Commercial scale Battery	4000	2000
food_processing	Process Heating	PV+Battery	4167	2500
food_processing	Process Heating	Heat Pump controller	250	213

Sub Sector	End Use	Technology Name	Variable Captial Cost KWp - 2023	Variable Capital Cost KWp - 2040
forestry_product	Process Heating	Commercial scale Battery	4000	2000
forestry_product	Process Heating	PV+Battery	4167	2500
forestry_product	Process Heating	Heat Pump controller	250	213
chemicals	Lights	Commercial scale Battery	2000	1000
chemicals	Lights	PV+Battery	4167	2500
food_processing	Water Heater	PV+Battery	4167	2500
food_processing	Water Heater	Commercial scale Battery	4000	2000
food_processing	Water Heater	Heat Pump controller	250	213
food_processing	Water Heater	Hot Water controller	833	708
other	Water Pump	Commercial scale Battery	4000	2000
other	Water Pump	PV+Battery	4167	2500
chemicals	HVAC	Commercial scale Battery	4000	2000
chemicals	HVAC	PV+Battery	4167	2500
chemicals	Lights	PV+Battery	4167	2500