Estimating the Technical Potential for Residential Household Appliances to Reduce Daily Peak Electricity Demand in New Zealand

By Carsten Dortans

A thesis submitted for the degree of Master of Arts at the University of Otago

Dunedin – New Zealand

March 2019

Acknowledgements

To my grandfather Franz: I would like to dedicate this work to you. You introduced me to nature and lived the idea that we can each play our own part to preserve it. Our walks through the forests seemed like a never-ending time. I miss your positive attitude and our profound conversations.

A very special gratitude goes out to my supervisors Dr. Ben Anderson, Dr. Janet Stephenson, and Dr. Michael Jack. Your support, patience, and valuable feedback right from the start of my Masters study was remarkable. Ben, without your insights and guidance into the world of programming I would not have been able to work on this analysis in the way I did. I am grateful for the financial support the GREEN Grid household electricity demand study has provided to me in my work as a research assistant.

There are many people along the way, but I certainly would not be where I am today without the encouraging words from Dr. Michael Römmich in the early months of 2017. To Bill Currie who introduced me to this beautiful place, thank you very much both of you.

I would like to thank my family, especially my mum and dad. Your support enabled me to conduct this research in the first place, and I hope to return the favour one day. A big thank you goes out to my aunt and great-aunt. You are always only one phone call away. I am also much obliged for the warmth and hospitality that Gwennyth and family provided to me, and I will remember this time well.

Thank you everyone at the Centre for Sustainability. This place is extraordinary. I always have the impression that we as a team are working towards something bigger, and I appreciate working together with every one of you. To Nicki and Gwenda, you are amazing, and I am grateful for all your help.

Now I would like to thank my friends wherever they are in the world right now. You make this life a wonderful experience and I believe that together we can achieve great things. To Rebecca, Will, Ismaël and Shakti, you always find the right words and I am very fortunate to know you.

On a warm summer day almost two years ago an aircraft departed from Düsseldorf, Germany. It was the start of an ‘adventure of a lifetime’, a time that promised to be and still is just as colourful as the eponymous Coldplay song.

As time continues to pass, it becomes clearer every day that the step to live in New Zealand, surrounded by friends, was the right decision, and I am more than excited to see what the future holds.

Publications

The NZ MBIE[1]-funded Renewable Energy and the Smart Grid (GREEN Grid) project has supported the preparation of two publications based on the research reported in this thesis. These were peer-reviewed by the wider GREENGrid project team and initially published via the Otago University Research Archive (OUR Archive):

1. Dortans, C., Anderson, B., Stephenson, J., & Jack, M. W. (2018). *Estimating the Technical Potential for Residential Demand Response in New Zealand* (Renewable Energy and the Smart Grid (GREEN Grid) Technical Report). Dunedin: Centre for Sustainability, University of Otago. Retrieved from https://ourarchive.otago.ac.nz/handle/10523/8579

2. Dortans, C., Anderson, B., Stephenson, J., & Jack, M. W. (2018). *Estimating the Technical Potential of Residential Demand Response in New Zealand: A Summary of Results* (Technical Report). Dunedin: Centre for Sustainability, University of Otago. Retrieved from http://hdl.handle.net/10523/8616

Furthermore, preliminary findings were presented as:

3. Dortans, C., (2018) "Estimating the technical potential for residential Demand Response in New Zealand". Otago Energy Research Centre Symposium on Energy and Climate Change, 23rd of November 2018, Otago Museum, Dunedin, New Zealand.

Author contributions are as follows:

- Mr. **Carsten Dortans** carried out all the analysis in the technical and summary reports, made all the figures, conducted the literature review and prepared the first draft of both reports.
- Dr. Ben Anderson provided preliminary analysis of overall NZ electricity demand, gave advice on data analysis and results presentation and contributed to the summary report.
- Dr. Michael Jack co-secured the funding to support the work, gave advice on data sources, data analysis, results presentation, commercial and policy implications and contributed to the summary report.
- Dr. Janet Stephenson co-secured the funding to support the work, gave advice on results presentation and policy implications and contributed to the summary report.

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[1] Ministry of Business, Innovation and Employment

Abstract

The successful operation of an electricity system necessitates balancing electricity supply and demand. It is widely recognized that fluctuations in electricity supply and demand have the potential to generate negative effects, such as jeopardizing the security of electricity supply. This leads to an inefficient use of the electricity system infrastructure.

In New Zealand, residential household appliances contribute significantly to national electricity demand and, in particular, to peak demand. Concurrently, electricity demand is forecast to increase. New Zealand's commitment to carbon neutrality by 2050 requires this increased demand to be met by fluctuating renewable energy sources, as hydroelectricity is operating at capacity. This will challenge the capacity of the electricity system to supply peak demand.

Sophisticated energy management targets peak demand and comprises of a mechanism referred to as demand side management to ensure system balance. Demand response and energy efficiency are two subsets of this mechanism. These two tools pursue different approaches to reducing peak demand. While demand response focuses on the timing of electricity demand, energy efficiency reduces total electricity demand, and thus peak demand.

This thesis estimates the technical potential of demand side management to reduce the electricity peak demand from key appliances in residential households. Sub-hourly data on the electricity demand profiles of hot water heaters, heat pumps, refrigeration, and lighting are used to develop average demand profiles. Subsequently, demand response scenarios that reduce or shift demand are combined with a forecast of energy-efficient lighting to estimate the power potential and its economic value.

The analysis shows that residential demand side management involving demand response for hot water heaters, heat pumps, and refrigeration, as well as energy efficiency applied to lighting, has a maximum technical potential of reducing national demand in winter by up to 34%. This equates to an average daily energy reduction of 12,700 MWh.

Based on current time-varying prices and typical congestion charges, the economic value of shifting the residential demand of hot water heaters, heat pumps, and refrigeration away from peak intervals was estimated to be up to $73 million NZD per year. Combined load shifting under demand response with energy-efficient lighting increases this annual economic value of demand side management to $164 million NZD. Demand response would also increase overall system efficiency. However, achievement depends on social and financial factors outside the scope of this thesis.

KEY WORDS: Demand Side Management; Demand Response; Energy Efficiency; Electricity; New Zealand; Residential; Households; Technical Potential.

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List of Abbreviations

CPD	Congestion Period Demand
DR	Electricity Demand Response
DSM	Demand Side Management
EE	Energy Efficiency
EECA	Energy Efficiency and Conservation Authority
GWh	Gigawatt Hour
MWh	Megawatt Hour
RBS	Residential Baseline Study

1. Introduction

In the context of Anthropogenic Climate Change there is an urgent need to re-evaluate the way electricity is generated and utilised to avoid the consequences of global warming above 1.5°C compared to pre-industrial levels. Limiting global warming to 1.5°C compared to pre-industrial levels requires *"[...] rapid and far-reaching transitions in energy, land, urban, and infrastructure (including transport and buildings)[...] These transitions are unprecedented in terms of scale[...]* (Allen et al., 2018, p. 21).

New Zealand has set targets to attain 90% electricity generation out of renewable energy sources by 2025, and 100% by 2030 (Ministry for the Environment, 2016). However, renewable energy sources are often highly dependent on environmental conditions, due to the volatile nature of solar irradiance, wind speed, and inflow of water into hydro lakes. This affects the amount of electricity that can be generated and controlled at different times of the day (Müller & Möst, 2018). These changing environmental conditions cause fluctuations in electricity generation.

In addition to fluctuating electricity generation there is also variation in electricity demand throughout the day and season. Daily variations in electricity demand generate demand peaks characterised by a higher utilisation of electricity at certain times of the day, predominately in the early morning and evening. This phenomenon does not solely occur in countries like New Zealand, Germany, or the United States of America but on a global level as well (Sigauke, 2012). Combined with fluctuating electricity generation, this challenges the successful operation of the electricity system as it jeopardises the vital balance between supply and demand (Spiecker & Weber, 2014).

Variations in electricity supply and demand require measures that ensure a balance between supply and demand (O'Connell et al., 2014). This has traditionally been achieved by investing in more generation. Demand side management (DSM) has however, the potential to reduce peak demand and, therefore, facilitate system operation. Demand response (DR) and energy efficiency (EE) are two mechanisms rooted in the concept of DSM. DR focuses on shifting the timing of electricity consumption to reduce peak demand.

This adjustment to the timing of consumption is attained through load shifting and load curtailment.

On the other hand, EE involves more permanent measures to reduce electricity demand in general (e.g. through upgrading to more efficient appliances). Fig. 1 presents the operational disparity of DR and EE that was visualised by Palensky and Dietrich (2011). It shows how clear DR curtails the power at a certain time whereas EE reduce power in general. Ideally, load curtailment does not result in a rebound effect that causes a power draw higher than the original one. However, certain appliances, such as heat pumps, incorporate characteristics that can lead to this effect (see section 2.1.4).

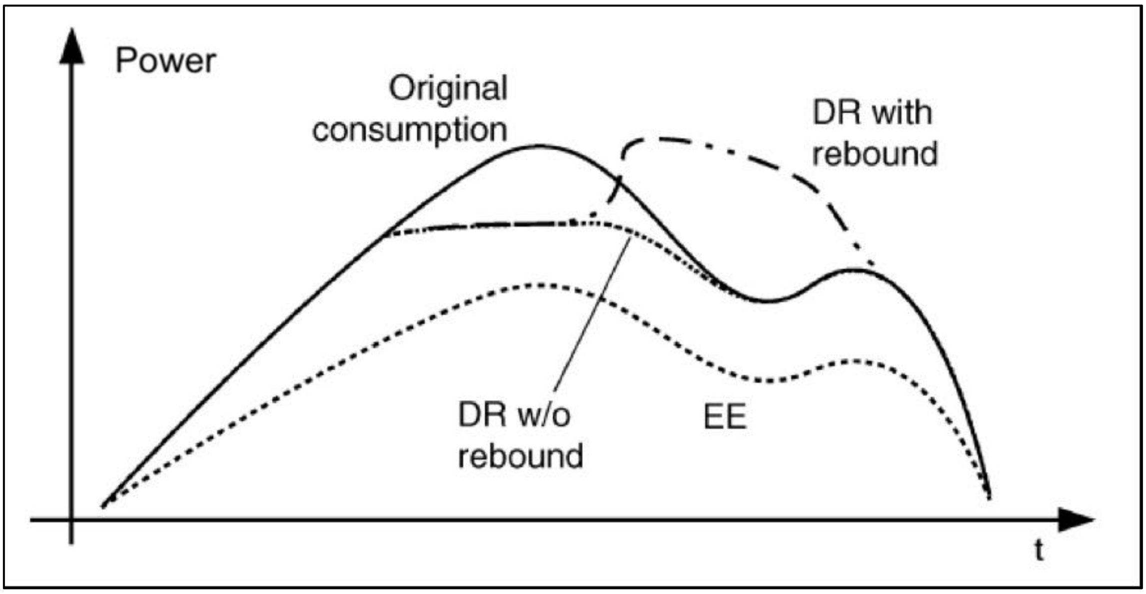


Fig. 1| Operational difference of DR and EE

Source: Based on (Palensky & Dietrich, 2011).

DR is particularly beneficial if applied to thermo-electric appliances such as hot water heaters, and refrigerators, or heat pumps in well-insulated homes where warm air can be retained that are capable of storing heat or cold. These significantly contribute to the overall electricity demand in New Zealand (see section 3.1) (Electricity Authority, 2018b). Applying DR mechanisms to shift demand from such appliances therefore has potential to reduce peak demand in New Zealand.

Appliances that do not have the storage ability of thermo-electric utilities may not be useful for DR. For example, lighting cannot be deferred and still carry out its function. Nevertheless, non-thermo-electric appliances can be incorporated and utilised in the context of EE to permanently reduce peak demand. For example: inefficient light bulbs can be substituted with more efficient ones that will reduce electricity demand and therefore peak demand.

Demand shifting and demand reduction appear to have significant potential to reduce peak demand. This is particularly the case for households, as they contribute most to morning and evening peak demand in New Zealand (see chapter 5).

Whilst attempts to estimate these potentials have been conducted in several studies (Arteconi et al., 2013; Bronski et al., 2015; Dyson et al., 2014; Gils, 2014), none have so far analysed the technical potential of DSM for the residential household sector in New Zealand.

This thesis aims to respond to this lack by estimating the technical potential of DSM applied to key residential appliances, to reduce daily peak electricity demand in New Zealand. This thesis focuses on the technical potential which is categorised as power potential and its economic value. It ignores social acceptability and the realisable potentials of DSM to reduce daily peak electricity demand. However, the technical potential is the first step in assessing the realisable potential and can be seen as the initial foundation on which further studies can build.

1.1 Research objectives

This study has three main research objectives. These are:

1. To analyse the demand patterns of key residential household appliances that significantly contribute to peak demand.

2. To develop scenarios that reduce and shift electricity demand into times of less demand (off-peak).

3. To estimate the technical potential of DSM to reduce daily peak demand of residential household appliances in New Zealand, and its economic value.

1.2 Thesis structure

Chapter 1 (Introduction) emphasises the necessity for sophisticated energy management to ensure a balanced electricity system by reducing daily peak demand. DR and EE are presented as two mechanisms of DSM to reduce peak demand and are distinguished from one another.

Chapter 2 (Literature Review) presents an analysis of the methodologies relevant to estimating the technical potential of residential DSM. Furthermore, this chapter positions the work conducted in this thesis in the context of recent international studies.

Chapter 3 (Electricity in the New Zealand Context) presents the current status of electricity demand and its fluctuations in New Zealand. A variety of tools associated with DR and EE are analysed and provide a broader understanding of DSM.

Chapter 4 (Data & Methods) elucidates the data sources and methods used to estimate the technical potential of DR and EE. A particular focus is on data transformation. The estimated results in this study require an understanding of the processes and approaches that were undertaken. This chapter provides the knowledge foundation for these results.

Chapter 5 (Results) encompasses the findings relating to power reductions and the economic value of DR and EE. First, power potentials of DSM applied to hot water heaters, heat pumps, refrigeration, and lighting are presented, as well as the aggregated effect of these appliances at peak times. The second part of the results chapter presents the economic value of DR and EE.

Chapter 6 (Discussion) discusses the overall findings of this thesis and relates these to international studies. Furthermore, limitations and further research on the topic of this thesis are presented.

Chapter 7 (Conclusion) summarises the overall findings and associates the research objectives with the main results.

2. Literature Review

This chapter aims to place the work in this thesis in the context of broader literature around the estimation of the technical potential linked to demand side management (DSM). The first section defines DR and EE as part of DSM and highlights the mechanisms of DSM pertinent to this thesis. In the second section, related studies that analyse the technical potential of DSM are discussed. This chapter concludes with a summary of limitations associated with technical potential estimates and establishes the connection to the research objectives that were defined in section 1.1.

2.1 Demand side management

Average electricity demand does not require all of the electricity system's generation and transmission infrastructure. Peaks significantly larger than the average result, however, in an over-investment in installed network components (Albadi & El-Saadany, 2007). In addition, electricity peak demand has the potential to cause stress on the utility grid (Gyamfi, Krumdieck, & Urmee, 2013). These issues are likely to be exacerbated by more variable renewable energy sources (Müller & Möst, 2018). To ensure an economically-efficient, low-carbon electricity system, particularly during times of peak demand with a restricted availability of renewable energy sources, mechanisms focusing on the management of electricity demand are necessary. This energy management can be achieved through DSM.

A variety of studies corroborate this necessity of balance and reduction of peak demand. Grunewald and Diakonova (2018) stated that real-time balance of supply and demand is vital for a successful system operation. They claim that, at certain times, the ability to provide this balance has potential to be more significant than efficiency of individual components in enhancing overall system efficiency. This gains significance especially in the context of an increasing integration of renewable energy sources that constitute variability of electricity generation. Losi et al. (2015) describes the current relatively inflexible electricity demand, and propose DSM as a tool to maximise the distribution of renewable energy sources by providing solutions to actively manage supply and demand. Curtis et al. (2018) highlights that DR is the main technique available to provide balance in electricity systems. However, they fail to consider EE as another mechanism to reduce daily peak demand.

DSM encompasses the shifting of demand and saving of power through measures that ultimately aim to enhance the operation of the electricity system through optimisation of resource allocation and the improvement of energy utilisation (Hu et al., 2013). DSM can thus assist in minimising the negative effects of peak demand on the electricity system. DSM comprises of four categories (Paterakis, Erdinç, & Catalão, 2017):

1) EE;
2) Energy savings;
3) Self-production, and
4) DR.

This thesis focuses on DR and EE as two overarching mechanisms that can potentially reduce daily peak demand caused by residential household appliances.

2.1.1 Definition of DR and EE

This section aims to define DR and EE in more detail, in order to clearly distinguish both approaches that have the ability to reduce daily peak electricity demand.

DR as a component of DSM counters the challenge of imbalance between electricity supply and demand. One definition of DR is:
"[...] end-use consumers intentionally altering their normal consumption patterns (by changing their instantaneous demand for electricity, the timing of their electricity consumption, or their total consumption of electricity), in response to electricity price changes, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardised." (Electricity Authority, 2015, pp. 1-2).

This definition incorporates DR definitions from the U. S. Department of Energy, the Federal Energy Regulatory Commission (FERC), and the pan-European Union of the Electricity Industry (Eurelectric). EE is excluded from this definition as it reduces electricity demand in general and does not take variable conditions in electricity generation into account (Electricity Authority, 2015). Based on the definition above, DR comprises mechanisms that change the consumption pattern of electricity consumers and can assist in retaining and improving the electricity system's low-carbon properties, and security of electricity supply.

EE offers another complementary measure for the reduction of daily peak demand, in the context of DSM. The World Energy Council defines EE as:
"[…] a reduction in the energy used for a given service (heating, lighting, etc.) or level of activity. The reduction in the energy consumption is usually associated with technological changes, but not always since it can also result from better organisation and management […]." (World Energy Council, 2008, p. 9).

Golušin et al. (2013) clarifies the difference between DR and EE by stating that EE constitutes mechanisms to reduce energy consumption while obtaining the same level of energy service, such as replacement of inefficient light bulbs. In contrast, DR or energy management in general, focuses on planning and optimisation of the timing of electricity consumption (Golušin et al., 2013). It becomes evident that DR and EE pursue two distinctive approaches to help reduce daily peak electricity demand.

2.1.2 Benefits

DSM provides benefits to a variety of stakeholders in the electricity system. In the following, the benefits of DSM are presented to corroborate the potential significance of DR and EE to enhance operation in the electricity system.

A likely future increase of electricity demand in New Zealand will challenge the ability of hydro powered generators to supply peak demand (Ministry of Business, Innovation & Employment, 2017). Current electricity peaks in New Zealand are mainly met by hydro power plants (see Khan et al., 2018), but in future DSM can help contain greenhouse gas emissions through reduced electricity demand. A reduction of energy demand through EE and shifting through DR can thus assist to maintain a carbon-neutral electricity generation. Another benefit that is associated particularly to EE, is the supply of electricity to more consumers with the same level of production capacity (World Energy Council, 2008). DR and EE thus enhance the security of electricity supply (Liu, 2017). Concurrently, through reduced electricity peak demand, DSM has the potential of deferring investment in new distribution and generation infrastructure and enabling current infrastructure to be used more cost-effectively (International Energy Agency, 2018). DSM comprises of tools that can relieve stress on the utility grid (Shao et al., 2011).

For households, DSM increases the purchasing power. Less spending on energy allows consumers to spend monetary resources on other things (International Energy Agency, 2018).

Through analysing energy markets in Europe and Northern Africa, Gils (2014) found that interventions in customer demand, as conducted through DR and EE, can increase profitability. The paper identified several GW of load in Germany and Austria suitable for DR as they comprise loads that are able to theoretically be shifted or shed (Gils, 2014).

Paterakis et al. (2017) connected the impact of DSM on operational and economic parameters in the electricity system to the possible contribution to a more sustainable electricity system through DR in general. A related study conducted by Losi et al. (2015) analysed these economic parameters and found that the reduction of peak demand in particular, the provision of ancillary service, and the reduction of transmission and distribution losses generate economic benefits associated with DSM.

This shows that DR and EE, as part of DSM, can potentially generate benefits for a variety of stakeholders in the electricity market such as the system operator, lines companies, and households.

2.1.3 Ancillary services

A further aspect of DSM that has been investigated in recent studies is the contribution of DR to ancillary services. Ancillary services aim to improve the system's stability and are thus linked to the reduction of peak demand.

Paulus and Borggrefe (2011) concluded that increasing penetration of renewable energy sources will likely lead to a rising demand for ancillary services. This broadens the value of DSM programme applications, as originally DSM was implemented to enhance the efficiency of existing electricity infrastructure such as e.g. power plants and transmission lines (Strbac, 2008). For ancillary services, DSM possesses an advantage compared to distributed energy storage in being able to provide flexibility. DSM can work with 100% efficiency as no energy conversions are required to provide this flexibility for the system (Lund et al., 2015).

Dyson et al. highlight that customers most suitable for DR (based on appliance ownership and use) should be prioritised, and a uniform participation should be avoided (Dyson et al., 2014). This would provide the benefit of obtaining the most value from ancillary services through fewer participants rather than applying DSM to customers that are not suitable for such measures (e.g. utilising air conditioning outside of the evening peak).

DR, as an ancillary service, is a tool that embraces a variety of mechanisms, each with its own individual time structure. Torriti and collaborators (2015) emphasised that the timing of electricity demand has a significant impact on system balancing, pricing structure, and grid development. Mechanisms that are capable of managing the timing of electricity demand (e.g. DR) are thus an important component of electricity system management.

The following section discusses significant mechanisms linked to DSM.

2.1.4 Mechanisms

During times of peak electricity use, DR involves actions on the customer's appliance or equipment that are capable of shifting or shedding power demand. DR is usually implemented by automated processes, aggregators, or price signals.

Aggregators associated with residential DR are intermediaries between the system operator and households (Gkatzikis et al., 2013). The system operator aims to minimise operational costs caused by fluctuating electricity supply and, in particular, electricity demand. Aggregators are monetarily incentivised to sell DR services to the system operator. These services affect electricity demand in the residential household sector and enhance utility grid stability.

The New Zealand electricity market currently contains a variety of DR mechanisms such as ripple control (RC), spot market pricing, curtailable load strategies, and instantaneous reserves (Electricity Authority, 2015; Strahan, 2014). These mechanisms provide DR at different timescales. Historical, current and potential future DR mechanisms across different timescales are summarised in Fig. 2 and Table 1 and depicted by individual indices. However, this classification does not imply that historic DR mechanisms, such as for instance RC, are not widely used in New Zealand any more but indicates the point in time of when these mechanisms were implemented.

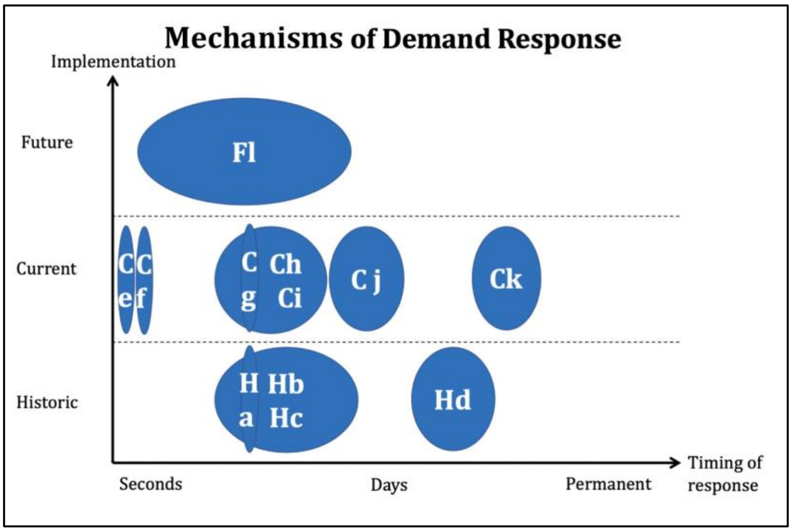


Fig. 2| Mechanisms of DR

Source: Based on (Strahan, 2014).

Table 1: Mechanisms of DR - explanation

Implementation index	Forms of demand response in the NZ electricity sector	Timing of response
Ha	Industrial consumers responding to spot price	30min
Hb	Distributors using ripple control	Minutes, hours
Hc	Providing interruptible load into instantaneous reserve market	Minutes, hours
Hd	Domestic consumers reducing consumption during conservation campaigns	Weeks, months
Ce	Interruptible load – Fast Instantaneous Reserve	Second
Cf	Interruptible load – Sustained Instantaneous Reserve	Seconds
Cg	Spot market pricing for domestic customers (Flick Energy)	30min
Ch	Increased availability of peak/off-peak tariffs for domestic consumers	Minutes, hours
Ci	Projects (EA's dispatchable demand, EA's DSBF project, Transpower's demand response programme)	Minutes, hours
Cj	Curtailable load	Hours, day
Ck	Seasonally varying prices (Powershop)	Months
Fl	Introduction of smart appliances and use by households and businesses	Minutes, hours

Source: Based on (Electricity Authority, 2015; Strahan, 2014).

In the following section, DR mechanisms pertinent to this thesis are elucidated and linked to recent studies.

One approach to pass on costs of network contingencies to customers to encourage load shifting is described in congestion period demand (CPD) charges, also referred to as control period demand. These charges occur at times when the electricity system (electricity generation, transmission lines, or distribution lines) reaches its maximum load and generates stress on the utility grid. To try and reduce demand during times of peak demand, customers (currently only commercial customers) face higher charges in dollars per kW. This charge is approximately equivalent to the cost of constructing another kW of capacity and incorporated in ‘Ch’ of Table 1 (Michael W. Jack, Ford, Dew, & Mason, 2016). For residential customers this charge is usually incorporated into lines charges and electricity price per kWh and not separately displayed, and thus currently in New Zealand most residential customers are not incentivised to shift demand.

Other forms of DR are curtailable load and load shifting, respectively. Load shifting is a DR strategy that considers electricity demand and shifts it to periods of time with less expected electricity demand, usually through price signals (López et al., 2015). A minimum customer size (kilowatt) is required to participate in curtailable load tariffs. Two forms of curtailable load are prevalent. The first form curtails an electricity load while the second form curtails the load only to a specific, predetermined level (Aalami, Moghaddam, & Yousefi, 2010). Fig. 3 demonstrates the second form of curtailable load where the initial load is curtailed to a predetermined level of approximately five-hundred kilowatts over nine hours.

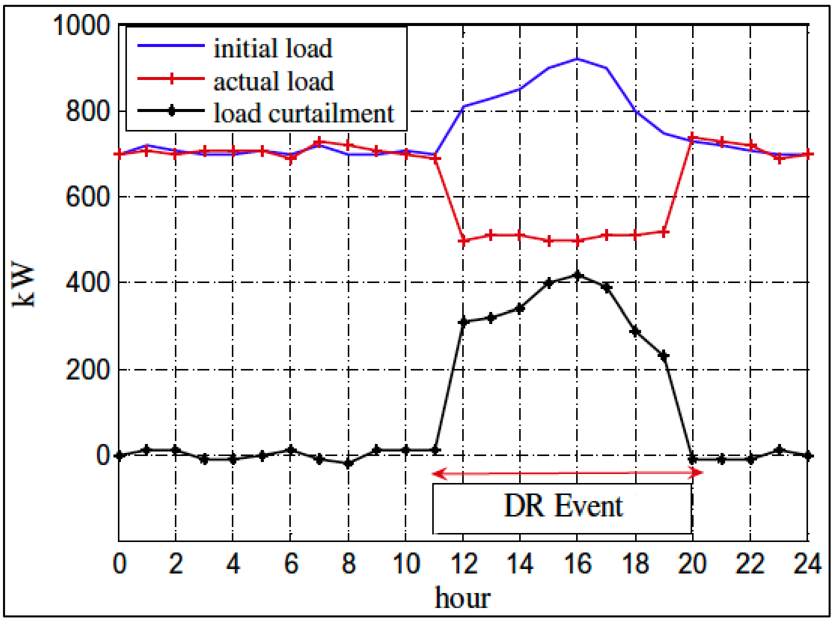


Fig. 3| Load curtailment during DR event

Source: (Chakrabarti, Bullen, Edwards, & Callaghan, 2012).

If less energy is used to provide the same output or service this is generally associated with EE (Patterson, 1996). In contrast to EE that permanently reduces electricity consumption by upgrading appliances or incorporating electricity saving measures, DR, especially the curtailment of load over a longer time, has the potential to generate a rebound effect in the electricity consumption pattern (Palensky & Dietrich, 2011). In the following, the example of heat pump use in winter season is utilised to clarify this effect.

Thermostatically controlled electricity-based heat pumps in winter attempt to maintain a certain temperature in residential households. While the heat pump is likely to operate at a level of e.g. fifty per cent once a predetermined temperature setting is reached, disengagement of the appliance and therefore temperature reduction of the space will lead to a higher electricity consumption once the appliance is turned on again. Instead of preserving a temperature level, there is now the need to overcome the difference between actual room temperature and predetermined temperature setting. The operation level could increase and if so, uses relatively more electricity compared to an appliance operation with no load interruption. If prevalent across the system, the rebound effect can shift the peak demand to a new time.

Much work focuses on identifying the present status or future implementation of DSM mechanisms such as DR and EE (Gellings, 1985; Grunewald & Diakonova, 2018; Liu, 2017;

Logenthiran et al., 2012; Lund et al., 2015; Meyabadi & Deihimi, 2017; Paterakis et al., 2017; Paulus & Borggrefe, 2011; Strbac, 2008; Torriti et al., 2015). This indicates the variety of mechanisms in electricity systems that aim to enhance the electricity system's operation.

Lund et al. (2015) extensively reviewed DSM options in electricity systems. The paper corroborates, that if renewable energy sources are implemented, new measures such as DR are necessary to provide balance in the system. These measures disrupt the conventional way of thinking how electricity systems operate (supply follows demand). In this context, information and communication technology is essential to incorporate DSM mechanisms. This technology enables the electricity system to be highly responsive to variations in electricity supply and demand (Darby & McKenna, 2012; Lund et al., 2015).

DSM mechanisms have also been studied in New Zealand. Strahan (2014) reviewed DR mechanisms that are currently established in the New Zealand electricity system. Strahan's analysis contributes to Fig. 2 of section 3.3.1 and provides a first overview of existing mechanisms and their characteristics. The review, furthermore, underlines the potential of DR to provide assistance to reduce peak demand on a variety of time scales.

In the broader sense of DSM, the Household Energy End-use Project (HEEP) conducted by Isaacs et al. (2006) delivered first hand insights on electricity usage in residential New Zealand households. 400 randomly selected houses were selected, covering diverse regions in New Zealand and providing data on energy flows in residential households on a ten-minute granularity level. The Project does not exclusively analyse electricity, but all fuels utilised in the household (i.e. electricity, gas, solid fuel, and oil). Isaacs et al. focussed on end-uses of the aforementioned fuels and provide an understanding where energy is used in households. Their analysis on how hot water heaters are powered constitutes the foundation of estimating power potentials linked to hot water heaters in this thesis. Concurrently, Isaacs's analysis corroborates the significance of hot water and space heating in the context of electricity consumption in residential households. This significance is clarified when EECA data on electricity consumption by household appliance is analysed.

EECA's Energy End Use Database allows stakeholders to explore energy consumption in a variety of sectors and thus provides authoritative data and statistics to enable informed decisions of stakeholders (Energy Efficiency and Conservation Authority, 2017b). The database is drawn from a number of sources such as Statistics New Zealand's Energy Use Survey, and industry associations. EECA data and data provided by the HEEP study on energy end uses are both used in this study.

Isaacs's work contributes to the selection of household appliances that comprise significant electricity consumption. However, the HEEP study does not analyse the potential of DSM mechanisms, but states the appliances that could be used for it prior to this analysis.

In contrast, the GREENGrid data set constitutes a more pertinent component to this thesis and depicts another New Zealand related study on DSM. High granularity monitored demand data, comprising of a number of appliances and circuits in residential New Zealand households, is the foundation of this data set. Related studies, amongst other things, focus on hot water electricity demand (see Jack et al., 2018) and the comparison of energy-related time-use diaries and monitored electricity demand (see Suomalainen et al., 2019). These studies are highly pertinent to this thesis and demonstrate the significance of hot water heater electricity demand in residential households.

This thesis draws data from all of the aforementioned studies and databases, but in particular the GREENGrid data set.

2.2 Estimating the technical potential of demand side management

This section examines methodologies that estimate the technical potential of DSM. A particular focus lies on the estimation of the power potential and its economic value.

2.2.1 Development over time

Scientific literature has a growing focus on DSM and its associated mechanisms. Boßmann and Eser (2016) extensively reviewed the origins and aspects of DR models. Their study finds that annual publications linked to DR models have tripled since 2006. Furthermore, studies, particularly from North America and Europe, constitute a major contribution. Fig. 4 and Fig. 5 illustrate these findings. The residential sector is most commonly analysed; fewer studies investigate the commercial sector (Boßmann & Eser, 2016). However, despite the significant contribution to national demand, the residential sector in New Zealand is less well explored (see section 3.3). This underlines the necessity of investigating the residential sector in this thesis.

Based on the aforementioned review, studies that incorporate technical aspects primarily conduct a bottom-up approach. This links to the work conducted in this thesis, where demand profiles of residential key appliances are scaled to depict impact on national demand.

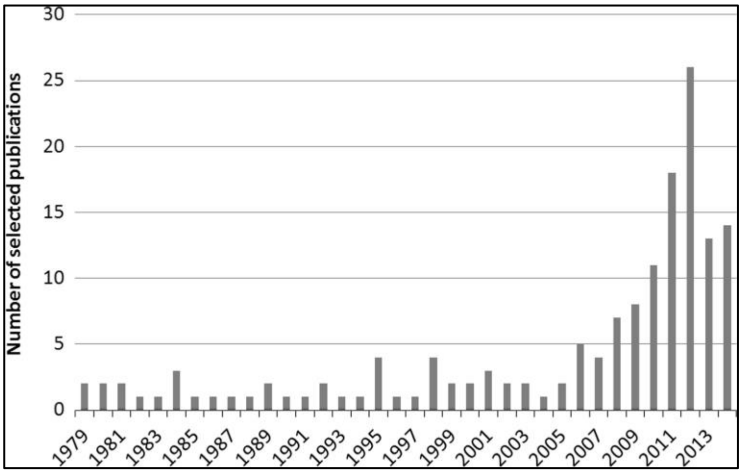


Fig. 4| Increasing penetration of demand response models

Source: (Boßmann & Eser, 2016).

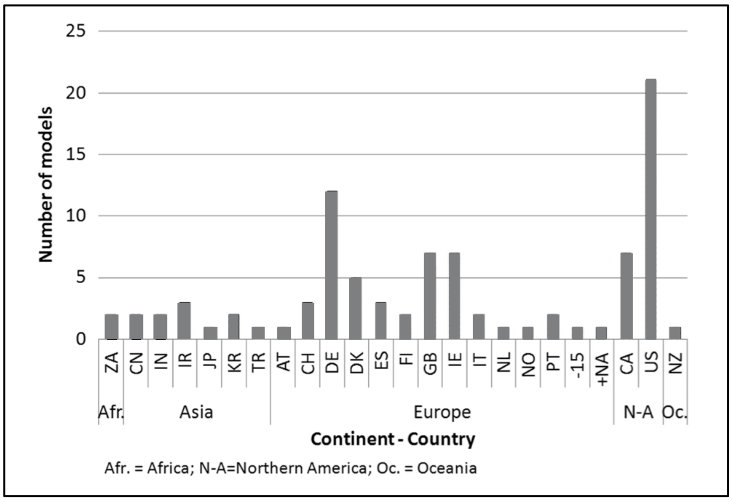


Fig. 5| Geographic allocation of demand response models

Source: Based on (Boßmann & Eser, 2016).

2.2.2 Power potential

An overarching classification of DSM options to encounter demand fluctuations is identified in the review conducted by Lund et al. (2015). This classification pertains to both power potential and to the economic value of DR and is utilised in many studies. Lund et al. (2015) identified three approaches to provide flexibility via DSM. These approaches are:

1) reducing load (either load curtailment via DR or EE),
2) increasing load (DR), and
3) rescheduling load (DR).

Many studies such as Arteconi et al. (2013), Gils (2014), Dyson et al. (2014), and Bronski et al. (2015) have incorporated load reduction and or load shifting into their analysis to estimate the power potential of DR to reduce daily peak demand. However, these studies do not consider EE to provide an equivalent outcome, and identify load shifting as the most beneficial approach. This is because, in contrast to reducing and increasing load, load shifting can avoid compromising some processes such as heating water in residential households. However, in order to enable load shifting, intermediate storage is necessary (Lund et al., 2015). It is also possible to increase the load at certain times of the day, to fill valleys of electricity demand (Lund et al., 2015). This thesis, however, does not address increasing load to overcome valleys of electricity demand. The focus is on the reduction and shifting of peak demand, by considering the prerequisite of intermediate storage ability for load shifting, as identified by Lund et al. (2015). This prerequisite is fulfilled by choosing residential household appliances that have an inherent storage ability as noted in section 3.1.

Studies conducted on load shifting utilise either monitored electricity demand data, such as Arteconi et al. (2013) and Dyson et al. (2014), or incorporate example load profiles as presented by Gils (2014). Utilising monitored load data provides the advantage of overcoming the limitation incorporated by load generalisation that constitutes example load profiles. However, Gils's study fails to apply monitored load profiles and thus limits the study's meaningfulness.

Three major approaches have been undertaken in studies that aim to estimate the technical potential of residential DSM. Studies focus either on:

1) one appliance (e.g. Arteconi et al., 2013; Dyson et al., 2014),
2) a few appliances (e.g. Bronski et al., 2015; Palmer, Terry, & Kane, 2013), or on
3) broader sectoral analyses and processes (e.g. Gils, 2014).

Some studies on DSM and its potential to reduce daily peak demand focus on only a fraction of the power potential. Arteconi (2013) and Dyson (2014) specifically analysed the power potential of DR linked to heat pumps and air conditioning in buildings. While this provides an estimate of the DR potential of space conditioning, the studies are limited to one appliance. Analysing one appliance does not provide a holistic notion of the power potential of DR and thus limits the research findings to the selected appliance and its contribution to peak demand.

In contrast, there are studies that analyse many processes and appliances in a variety of sectors, such as Gils (2014). The study links appliances and processes to sectors such as the commercial, tertiary, and residential sectors. Each appliance and process is then connected to either load reduction or load shifting. However, by focusing on a large number of appliances, the DR potential in Gils's study is not assessed, so the analysis superficially investigates characteristics that are connected to DR.

A more thorough analysis of the power potential and its economic value is provided by Gils in a model-based assessment of DR by focusing on load shifting and load curtailment (Gils, 2016). The study utilises a model and linear optimisation to predict the technical potential of DSM based on estimates of increasing renewable energy sources in the future electricity system in Germany. This model-based approach to forecast energy consumption in future years constitutes a significant component of the analysis in this thesis and is further elucidated in chapter four.

A further study that extensively analysed the technical potential of DSM linked to the residential household sector in England was conducted by Palmer, Kerry, and Kane (2013). The study's main objectives were the identification and understanding of appliance usage patterns and the documentation and analysis of user habits. The study identifies considerable scope for load shifting linked to residential lighting and also emphasises the potential for EE to reduce peak demand by at least as much as load shifting (Palmer et al., 2013). Similar to the studies conducted by Arteconi et al. (2013), Dyson et al. (2014), and Bronski et al. (2015), this study performed in the United Kingdom incorporated monitored electricity demand profiles. However, in contrast to Arteconi et al. (2013) and Dyson et al. (2014), the study utilises a much larger sample size of 250 households and implements more than one appliance in the analysis, similar to the study from Bronski et al. (2015). Palmer et al. (2013) incorporated many aspects that are used in this thesis as well. This facilitates the analysis in the New Zealand context and clarifies the possible potential of both DR and EE to reduce peak electricity demand.

Fig. 6 summarises these typical approaches. The red path (bold in black and white print) highlights the approach pursued in this thesis.

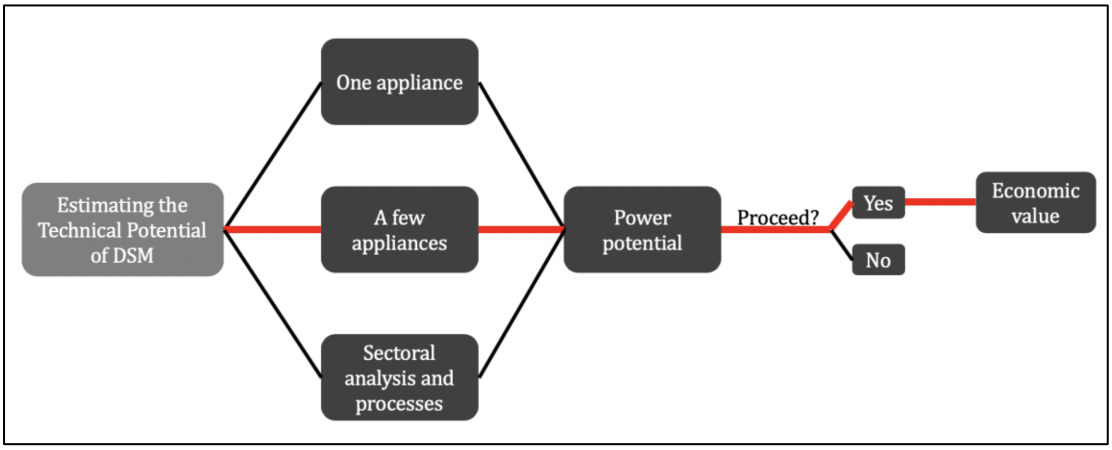


Fig. 6| Approaches to estimate the technical potential of residential DSM

2.2.3 Economic value

Since economic value is strongly connected to utilised energy, estimating the economic value requires the analysis of power potentials first. This then provides the necessary foundation for the estimation of the economic value.

Recent studies distinguish between incentive- and price-based DR (e.g. Albadi & El-Saadany, 2007; Losi et al., 2015; Paterakis et al., 2017; Strahan, 2014). These measures are amongst other mechanisms connected to electricity prices. These price signals can take on two forms. The first approach is price-based and charges customers a higher electricity price at peak demand to encourage off-peak electricity consumption. The second approach is incentive-based and constitutes incentive payments that allow a third party (i.e. operators, aggregators, and utilities) to regulate the customer's electricity demand (Losi et al., 2015).

Despite the prevalence of categorisation into incentive- and price-based approaches in the literature, this work does not identify approaches to estimate the economic value of DSM. This is because the two addressed economic components in this thesis (spot market prices and CPD charges) are both price-based.

Bel et al. (2009) developed a methodology that focuses on the technical potential of each individual customer in the commercial sector to reduce peak demand for various periods. Similar to the work conducted by Gils in 2014 their study concentrates on pre-defined market segments, processes, and the economic evaluation of these segments. Simulations are used to determine flexible energy. Subsequently, this assessed energy is connected to two cost components 1) direct cost (cost of providing the technical requirements for participating in DSM), and 2) indirect cost (cost associated with impact on service quality). A similar segmental analysis was conducted by Torriti et al. (2010) on the commercial sector in Spain.

Bronski et al. (2015), analysed the economic value of DR based on monitored electricity consumption data (15 min granularity) in Northern California in the United States of America. This analysis incorporated four electricity pricing scenarios: 1) time-varying electricity pricing, 2) residential demand charges, 3) reduced compensation for exported solar-photovoltaic, and 4) increased fixed charges (Bronski et al., 2015). Each pricing mechanism is chosen and based on existing energy projects in the country that reduce daily peak demand.

Bronski et al. (2015) found, that under their introduced scenarios and assumptions, DR can shift up to 20% of the annual electricity demand. Furthermore, real-time pricing connected to load shifting could generate savings of up to 12% per year. However, this study neglects the potential of EE to assist in demand reduction.

A further study that extensively analysed the technical potential including the economic value of DSM for the residential household sector in England, was conducted by Palmer, Kerry, and Kane (2013). The study's main objectives were the identification and understanding of appliance usage patterns and the documentation and analysis of user habits. The study identifies considerable scope for load shifting linked to residential lighting and also emphasises the potential for EE to reduce peak demand by at least as much as load shifting (Palmer et al., 2013). Similar to the studies conducted by Arteconi et al. (2013), Dyson et al. (2014), and Bronski et al. (2015), this study, performed in the United Kingdom, incorporated monitored electricity demand profiles. However, in contrast to Arteconi et al. (2013) and Dyson et al. (2014) the study utilises a much larger sample size of 250 households and evaluates more than one appliance in the analysis, similar to the study of Bronski et al. (2015). Palmer et al. (2013) incorporated scenarios and approaches to process monitored demand data that are utilised in this thesis as well. These approaches and findings regarding electricity demand in the residential household sector facilitate the analysis in the New Zealand context and clarify the possible potential of residential DSM to reduce peak electricity demand.

2.3 Scope of proposed research

As electricity systems do not share the same characteristics, it is understandable that the estimation of the technical potential cannot be transferred from one country to another. Furthermore, electricity systems are complex, and a holistic investigation is difficult to perform. Assumptions and models facilitate the process of estimating the technical potential of residential DR but, at the same time, build an environment that limits accuracy. Estimating the technical potential of residential DR constitutes the foundation for assessing the realisable potential which incorporates a broader set of characteristics. This thesis aims to build a foundation for further work.

Work pertaining to estimating the technical potential of residential DSM in New Zealand is very limited. As the HEEP study and Strahan's work on reviewing DR mechanisms in New Zealand falls short in estimating DSM potentials, there is scope to address this deficiency. Furthermore, the literature review reveals that research using monitored electricity demand profiles is more beneficial than using example demand profiles. This links to the initial research objectives presented in section 1.1. A clear understanding of demand patterns is necessary to estimate the technical potential of residential DSM. This requires monitored demand profiles and an understanding of how these demand patterns affect electricity peak demand.

Bronski et al. (2015), as well as Palmer et al. (2013) have developed DR scenarios. The idea of these scenarios to curtail and shift load is used and further developed to fit the purpose of this thesis. This further development is necessary to apply DR scenarios to the New Zealand electricity system, which is different from the systems operating in the United States (Bronski et al.) and the United Kingdom (Palmer et al.). The literature review also shows that there is a significant power potential and economic value in both DR and EE connected to residential household appliances. This thesis considers both mechanisms for estimating the technical potential of residential DSM to reduce daily peak electricity demand in New Zealand.

The literature review enhanced the understanding of methodologies and databases that assist in estimating the technical potential of residential DSM in New Zealand. In particular, the insights on incorporating multiple appliances with storage ability are used in this thesis. Furthermore, EE was identified as a significant component of DSM. Hence this thesis addresses both DR and EE. The benefit of monitored electricity demand profiles in contrast to example demand profiles was presented and is considered in the analysis. Associating the technical potential with its economic value was identified as a reasonable approach to enable a more holistic estimation of residential DSM potential. To enable this analysis in New Zealand, a number of data sets are incorporated. These data sets are drawn from the GREENGrid data set on monitored electricity demand profiles, the EECA Energy End Use Database on energy end-uses, Statistics New Zealand on population prevalence, as well as from the HEEP study on the basic ideas of energy distribution and consumption in residential households. The previous paragraphs described what this thesis proposes to analyse. In contrast, in the following, content that is not addressed in this thesis is presented.

Studies performed by Bronski et al. (2015), and Dyson et al. (2014) increase study robustness and meaningfulness by adding regional variability, temperature interference, social impact of DR, and a large sample size. These aspects exceed the scope of this thesis, which is dependent on existing data sets. Furthermore, data availability of monitored appliances and participating households, as well as an absence of regional variation in statistics restrict the granularity of this work.

As aforementioned, this thesis focusses only on the technical potential and not the realisable potential of DSM, which would include a behavioural analysis. Changing energy behaviours is difficult (Srivastava et al., 2018; Wang et al., 2011) and the presented DR scenarios, if implemented, would have impact on the life quality of customers. A thorough analysis considering social habits and attitudes towards DR and its influences (Fell et al., 2015; Spence et al., 2015) is thus necessary to understand how much of the technical potential would actually be realisable in New Zealand. Such analysis would need to incorporate customers as well as key participants in the electricity value chain to illuminate DR opportunities and challenges at the different levels of the electricity system and elaborate the attractiveness of DR scenarios for residential customers in New Zealand based on the analysis of social habits.

The following chapter presents the characteristics that constitute New Zealand's electricity system and aims to clarify the necessity for DSM to reduce peaks in electricity demand.

3. Electricity in the New Zealand Context

New Zealand relies on national electricity generation, as no opportunity exists to exchange electricity with adjacent countries. The requirement of maintaining a balance within this interconnected electricity system invites analysis of DR and Energy Efficiency (EE) potentials to assist with balancing. This is because both mechanisms have the potential of influencing peak electricity demand. In this section, a brief summary of current electricity demand and DSM in New Zealand is presented.

This chapter initially focuses on overall electricity demand in New Zealand. Subsequently, daily and seasonal demand variations are revealed and current DR and EE mechanisms that meet these variations in New Zealand are presented.

3.1 Annual electricity demand

In 2015, electricity consumption in New Zealand was 39,767 Gigawatt hours (GWh) (Energy Efficiency and Conservation Authority, 2017a). Compared to the previous year, that was an increase of 1.5%.

Fig. 7 portrays the total electricity demand by end use for 2015 in GWh. Aluminium Manufacturing (16%), Motive Power (14%), Refrigeration (13%), and Water Heating (12%) encompass more than half of the utilised electricity. This is followed by Lighting (11%) and Space Heating (10%) (Energy Efficiency and Conservation Authority, 2017a).

Fig. 8 extends this perspective and shows the total electricity demand by sector for 2015. Households in New Zealand represent 31% of the total nation-wide electricity consumption, followed by Primary Metal Production and Manufacturing (16%), and then Dairy Cattle Farming (5%).

Fig. 9 shows the estimated electricity consumption by different household appliances. This shows high domestic electricity use in refrigeration, water heating, lighting, and space heating.

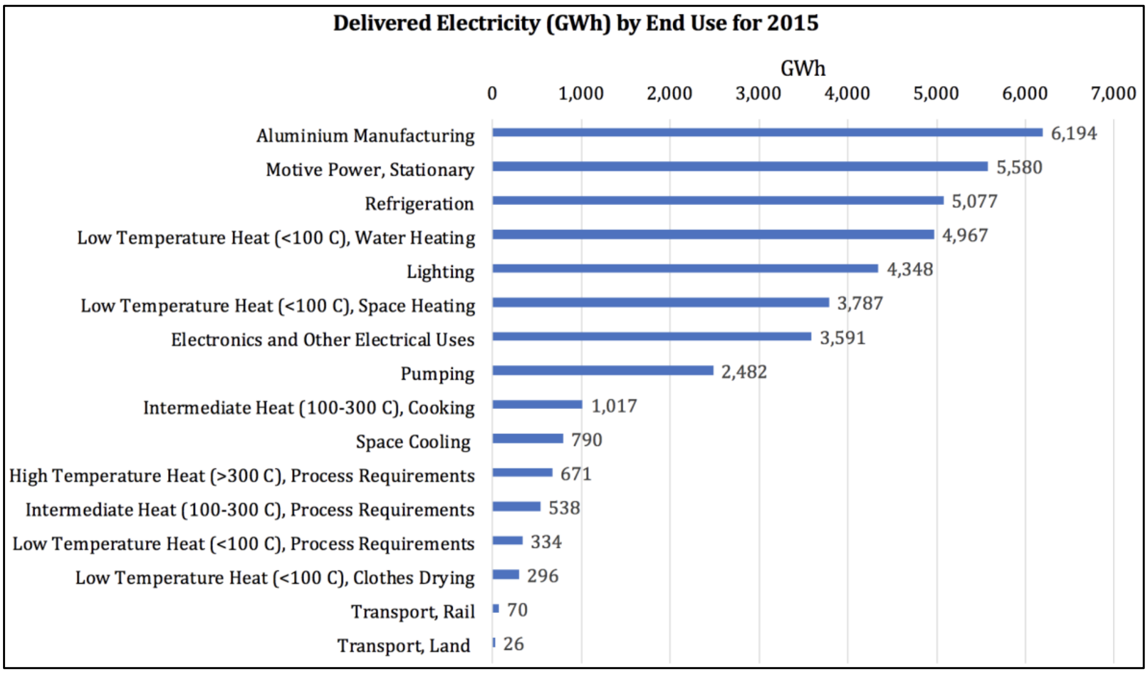


Fig. 7| Total electricity demand by end use for 2015

Source: Based on (Energy Efficiency and Conservation Authority, 2017a).

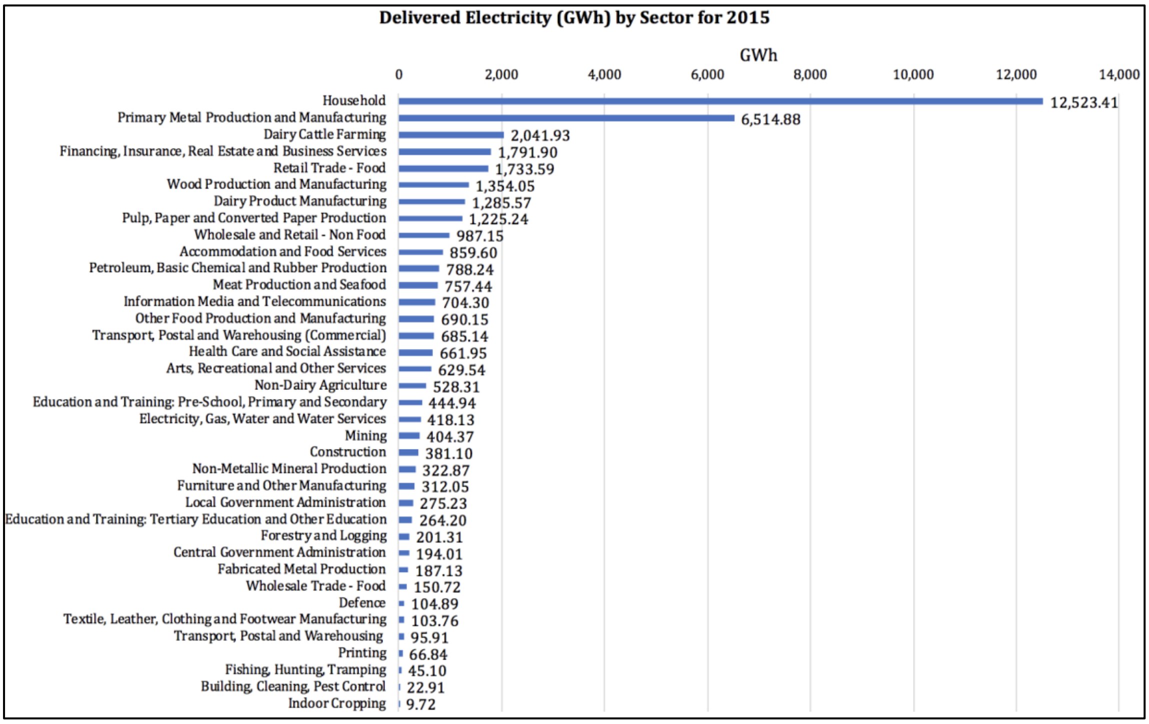


Fig. 8| Total electricity demand by sector for 2015

Source: Based on (Energy Efficiency and Conservation Authority, 2017a).

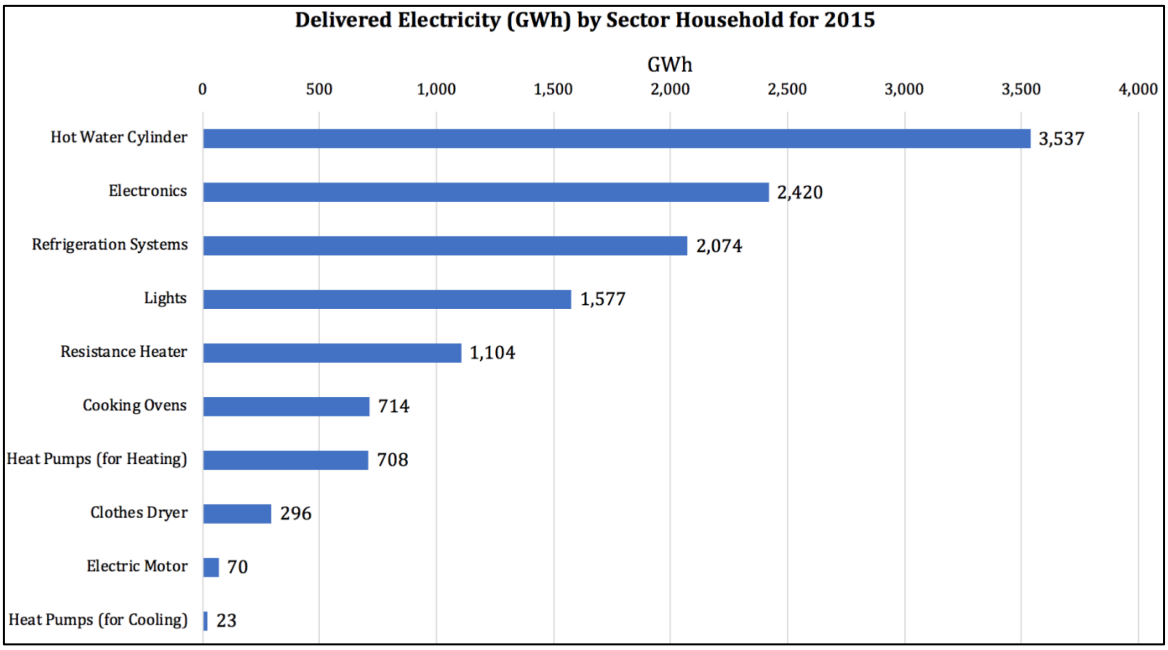


Fig. 9| Total electricity demand by technology in the household sector for 2015

Source: Based on (Energy Efficiency and Conservation Authority, 2017a).

In 2015, hot water cylinders in residential households accounted for 28% of the total electricity consumption (Fig. 9). "Electronics", a group of miscellaneous appliances that cannot be aligned with other categories accounted for 19% while Refrigeration Systems (17%) and Lights (13%) were the next highest. Heat Pumps, in this context, account for six per cent of the total electricity consumption in the household sector.

Residential hot water heaters, refrigeration systems, resistive heaters, and heat pumps have storage ability, since interrupting these appliances does not necessarily lead to an impact on service. These appliances have the ability to execute their individual purpose even when the electricity supply is interrupted due to the ability of hot (or cold) to be potentially 'stored' for a period of time, either in the device or within the room or house (for heating and cooling devices).

Lighting, in contrast, does not have such storage ability. To fulfil its purpose lighting is dependent on the time when it is actually needed, with no possibility to store it beforehand. The analysis in this paper will therefore focus on residential household appliances with and without storage ability that comprises significant electricity consumption, for which suitable data is available for analysis (see chapter 4). These are hot water heaters, refrigeration systems, and heat pumps (storage ability) and lighting (no storage ability).

Summarising the electricity demand landscape in New Zealand, households utilise the most electricity by sector and, notably, appliances with a storage ability such as hot water systems, refrigeration systems and heat pumps are major uses.

3.2 Variation in electricity demand

The daily average profile of electricity demand for summer and winter 2017 in New Zealand is shown in Fig. 11. This shows two distinct peaks during winter and fewer, more consistent increases, in summer. This indicates that times of peak demand, especially in winter (colder, longer nights), are characterised by a higher electricity supply and demand with peaks increasing at 08:00 and 17:00. The maximum power on an average day in winter 2017 was 6.2 GW (equivalent to 3.1 GWh per half-hour) and 5 GW in summer.

The activities of the residential household sector have a significant impact on this demand (Electricity Commission, 2005). The contribution of the residential sector is illustrated in Fig. 10. In Auckland, the residential sector constituted 54% of the total peak demand in winter in 2005, followed by commercial demand that constituted 30%.

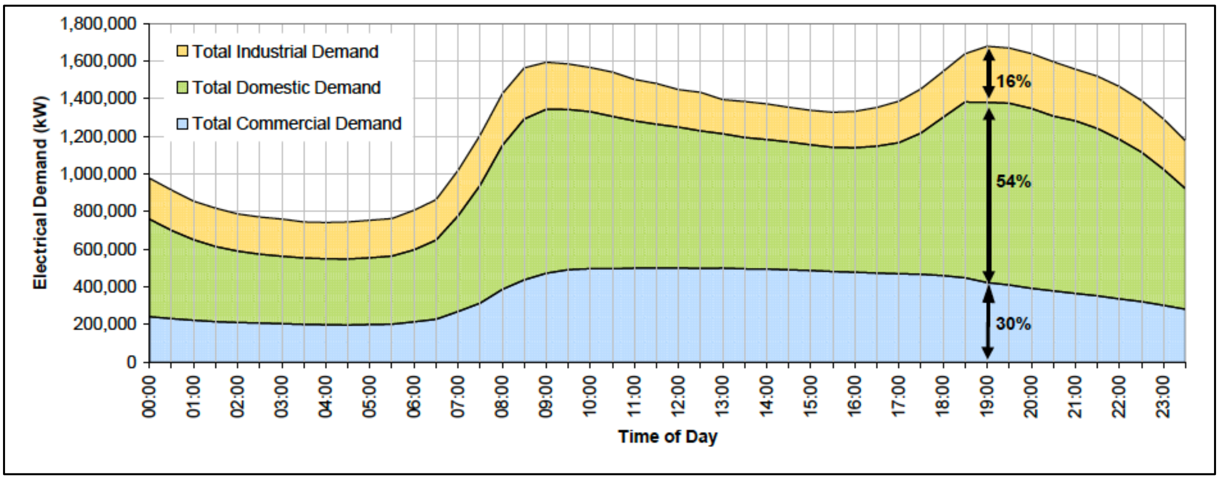


Fig. 10| Winter peak demand components in Auckland, New Zealand

Source: (Electricity Commission, 2005)

Times of electricity peaks change by season. In summer 2017, the evening peak was much flatter and occurred slightly earlier compared to winter of the same year. This change in the electricity supply pattern is likely to be caused by weather conditions in summer that involves less use of appliances such as electrical heating systems, coupled with daylight saving and also longer daylight hours for summer, leading to a lower use of lighting technologies (Sailor, 2001).

Electricity in New Zealand is generated from multiple sources including hydro, geothermal, gas, coal, and wind. Fig. 12 exhibits these sources and, furthermore, emphasises the proportion of each utilised fuel in June and December 2017. There is higher electricity generation in June (3,600 GWh) compared with December (3,300 GWh). This significantly higher electricity generation in winter is mostly caused by space heating demand (Isaacs et al., 2006). More than half of the total electricity was supplied by hydro electricity generation, and geothermal and gas each supplied 700 GWh per month. Wind and coal electricity generation take on a minor proportion of approximately 100 GWh per month.

All figures and calculations in this thesis take into account New Zealand daylight saving.

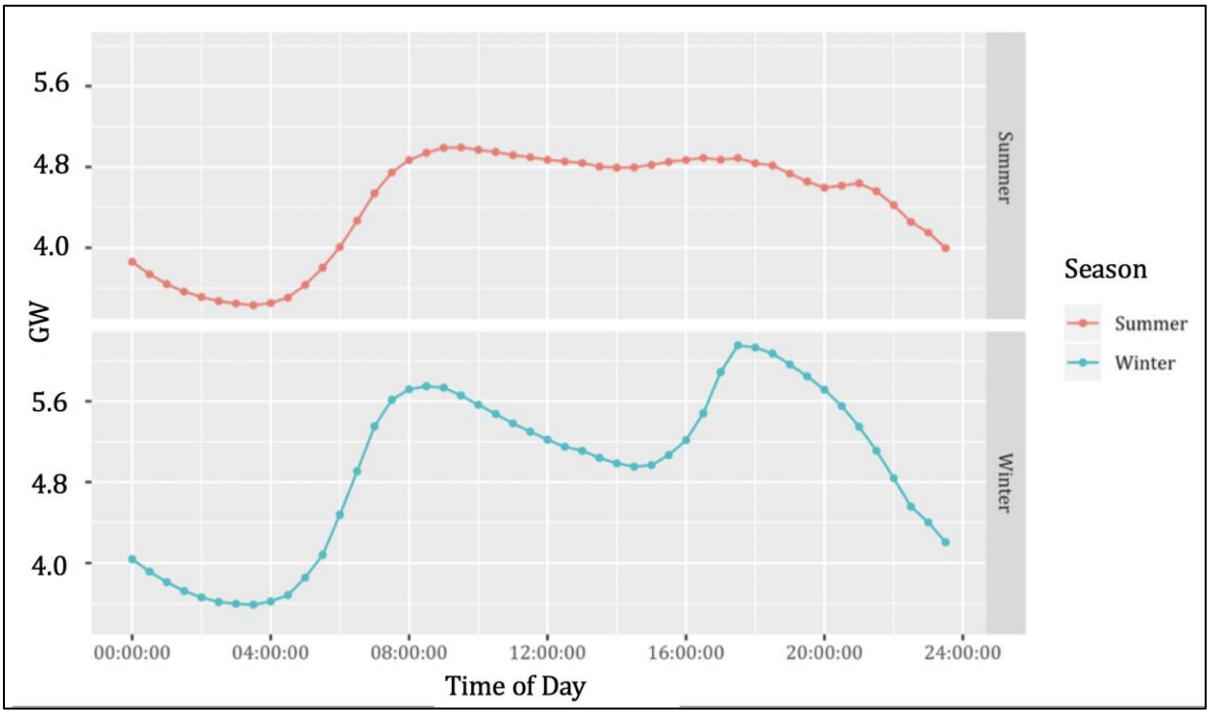


Fig. 11| Daily average electricity demand profile in summer and winter 2017

Source: Based on (Electricity Authority, 2018c)

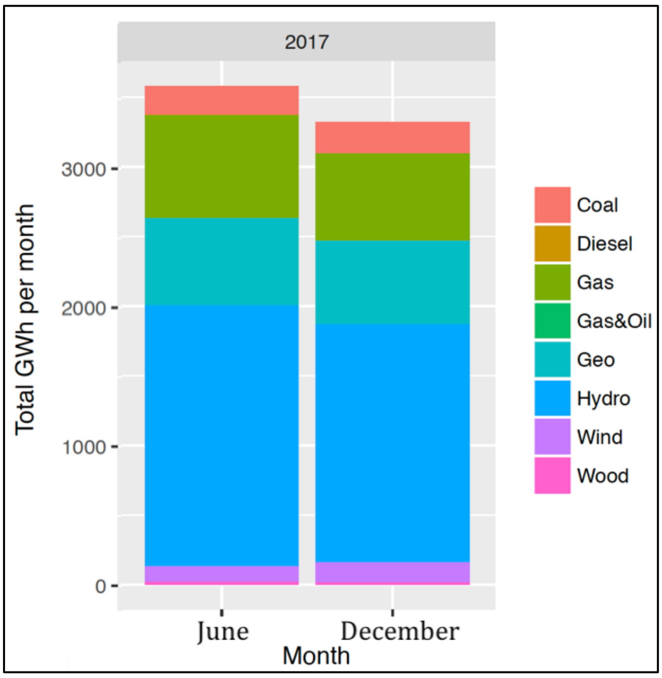


Fig. 12| Total electricity generation per month

Source: Based on (Anderson et al., 2018).

Increased demand during daily peaks in demand are largely met by hydro and to a smaller extent by gas electricity generation (Khan et al., 2018). This is in contrast to many other countries where peak demand is met by fossil fuel generation, for example in Germany and the United Kingdom (Burger, 2018; Torriti et al., 2015). Because of this, there is no strong connection between peak-demand time periods and carbon intensity in New Zealand (Khan et al., 2018). Hydro electricity generation as depicted in Fig. 13 represents a significant part of New Zealand's electricity supply and necessitates active monitoring and management (Transpower New Zealand Limited, 2018c). This capacity management considers the storage of hydro for future electricity generation. However, hydro storage in New Zealand is dependent on seasonal environmental conditions and as electricity demand grows, in the future it may not have the capacity to meet demand peaks. This absence of hydro capacity to meet future peak demand in combination with the strong daily variability, especially in winter, indicates the necessity for managing electricity supply and demand more efficiently. This energy management can be supplied by DSM.

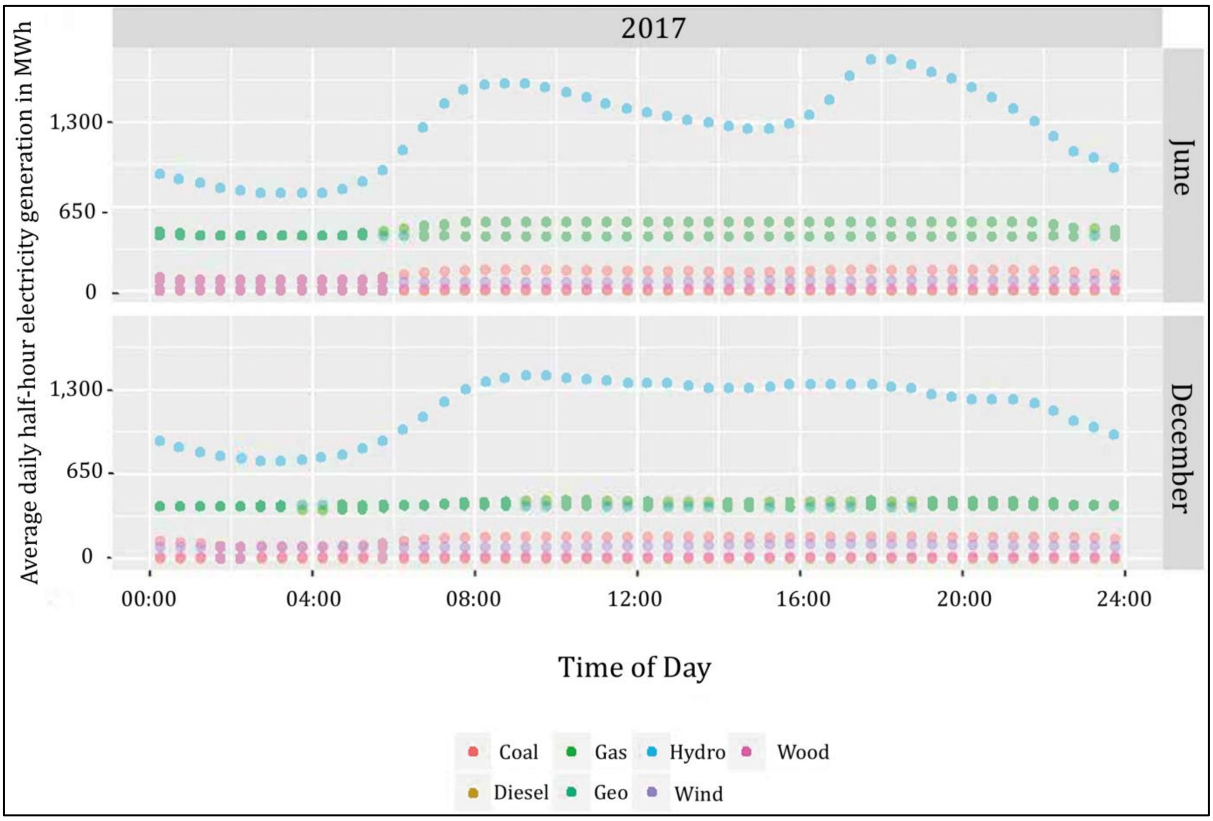


Fig. 13| Average daily half-hour electricity generation profile by sources in June and December

Source: Based on (Anderson et al., 2018).

3.3 Demand side management in New Zealand

The New Zealand Productivity Commission (2018) forecasts that DSM and distributed renewable energy resources, such as solar-photovoltaic and small-scale wind, will have an important role in New Zealand's future electricity system. Thermal power plants that operate at peak electricity demand need to be avoided in order to achieve carbon neutrality (New Zealand Productivity Commission, 2018). Concurrently, the commission highlights that DSM can reduce the need for hydro power to balance peak electricity demand when solar-photovoltaic and wind are unavailable.

The previous section highlighted the variation of daily electricity demand and clarified the existence of peak electricity demand. The following section presents the established DR and EE mechanisms of the New Zealand's electricity system.

3.3.1 Demand response

While a number of mature DR mechanisms exist in the industrial and commercial sector, the potential for DR in the residential sector is less well explored (see section 3.3.1), even though the residential sector is the main contributor to peak demand in New Zealand (Electricity Commission, 2005). Hot water heaters, heat pumps, and refrigeration appliances constitute a significant component of electricity consumption of residential households in New Zealand (Burrough, 2010) and also make up a significant component of consumption during peak time periods (Electricity Commission, 2005). In addition, these thermo-electric appliances have the ability to store energy in the form of heat or cold, providing a time buffer between electricity demand and the service they provide. These residential household appliances are, therefore, particularly suited being used for DR mechanisms that aim to reduce daily peaks because they embody both a contribution to peak demand and the ability to store energy.

3.3.1.1 Spot market pricing

The spot market in New Zealand is an essential part of real-time DR programs through representing alterations in electricity spot market prices based on electricity supply and electricity demand. Twenty-five electricity retailers operate in New Zealand (May, 2018) and build a competitive market environment. Competition between retailers leads to the development of business models. These business models are based on New Zealand's unbundled electricity market. This means that distribution of electricity is separated from generation and retail and, amongst other effects, enables customers to choose and change their electricity retailer (Ministry of Business, Innovation & Employment, 2010). Industrial and more recently residential electricity consumers are able to respond to time-of-use electricity price signals. Spot market energy volumes in New Zealand are traded every thirty minutes. They allow electricity consumers to buy and utilise electricity during times when the price for one unit of electricity (e.g. MWh) is lower than during times of a high level of electricity demand. Fig. 14 and Fig. 15 illustrate the relationship between electricity demand (in New Zealand equivalent to electricity generation) and increasing electricity prices for summer and winter 2017. Electricity peaks are clearly visible. In summer, only one peak exists while the winter electricity demand is characterised by two clearly visible peaks. The first peak in both seasons occurs at approximately 09:00 (trading period 18), the second peak in winter at 18:00 in the evening (trading period 36). As can be seen, electricity prices on the spot market follow a similar trend to electricity demand but are often more volatile, particularly at evening trading periods.

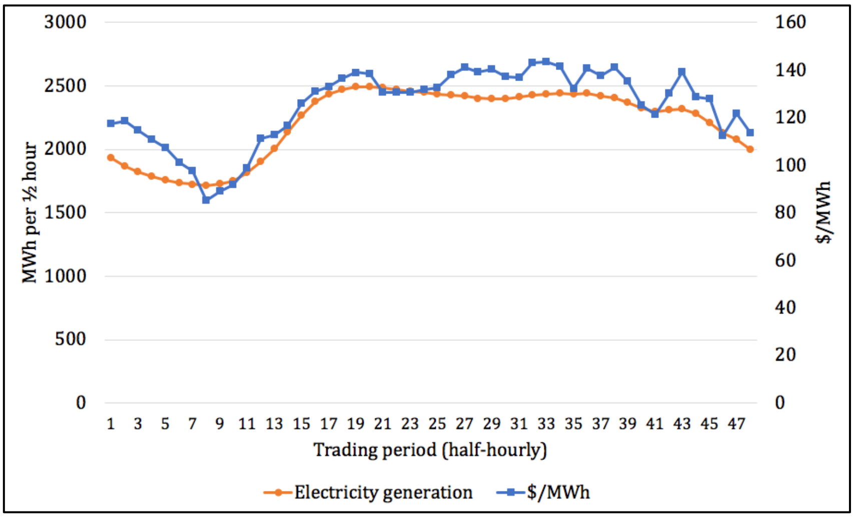


Fig. 14| Daily average electricity generation and spot market price profile for summer 2017

Source: Based on (Electricity Authority, 2018b, 2018e).

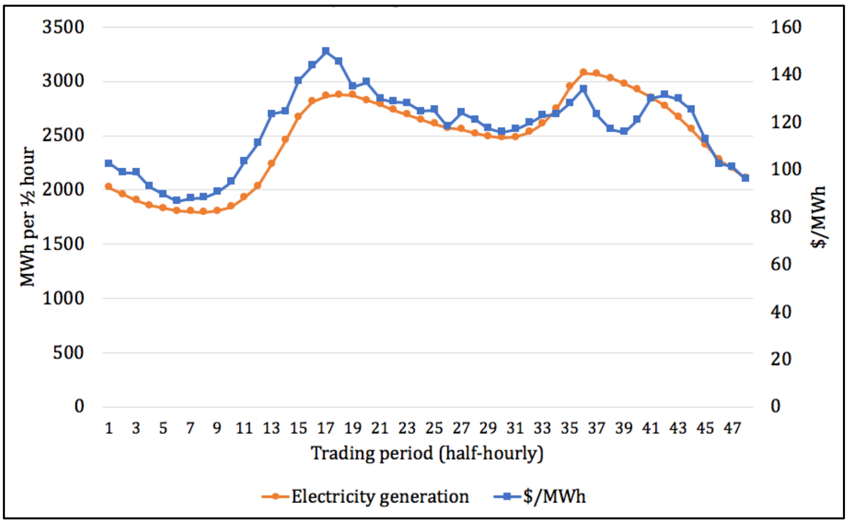


Fig. 15| Daily average electricity generation and spot market price profile for winter 2017

Source: Based on (Electricity Authority, 2018b, 2018e).

There is a gradually increasing number of electricity customers in New Zealand who choose to be on an electricity tariff, with time-of-use or real-time electricity price component. Residential consumers have only recently had the opportunity to buy electricity based on spot market prices, while industrial electricity consumers have had this opportunity for much longer.

Such services provided enhance the utility grid operationality and highlight the potential of DR mechanisms in New Zealand (Electricity Authority, 2018d). For example, since 2014 the electricity retailer Flick Electric Co has provided a retail service for residential and business customers which incorporates spot market electricity prices at the residential and business customers' end (Flick Electric Co., 2018a). Participating consumers are required to install a smart meter at their property, to allow real-time information on electricity supply and demand to be transmitted to the retailer. To facilitate this data transmission, Flick Electric Co. supplies electricity consumers with a mobile application to monitor the current spot market price developments and with further services to design spot market pricing which is comfortable, easily accessible, and which establishes informed decision making (Flick Electric Co., 2018b). Purchasing electricity directly from the spot market encourages a reduction of electricity usage during times that are characterised by a high electricity demand and a high spot market electricity price. In contrast to electricity tariffs with a fixed electricity price, this describes a tariff approach with a time-of-use component.

3.3.1.2 Ripple control

Ripple control (RC) is a historical and widely utilised form of DR in New Zealand. Installed in the 1950s as a measure of controlling load during intervals of low hydro electricity generation, RC partially cuts off load at the customer's premises (usually hot water systems) and thus enhances the balance of electricity supply and electricity demand (Ministry of Business, Innovation & Employment - New Zealand Smart Grid Forum, 2015). Via the electricity distribution system, a frequency signal is received by ripple receivers and initiates load curtailment, until a second signal enables the appliance's operation again. RC provides lower electricity charges for customers, but requires the consent of customers in cutting the load at certain times. These times are not announced prior to the DR event. RC is also utilised at fixed times, to switch street lights on and off. It is furthermore used to facilitate electricity tariffs aiming to switch from day- to night-tariffs.

Development in the electricity system over the last seventy years has changed the use and extent of RC in New Zealand. In 2006 RC transmitters were owned by twenty-seven different owners, most of which were lines companies. Many consumers, especially those based in the North Island, have switched to gas water heating and do not use electricity for water heating. Load control programmes, such as Transpower's DR programme, Instantaneous Reserve (described in more detail below), and RC, compete with each other leading to a decreasing need for RC. Some smart meter technology also has the capability of controlling load, but these are not necessarily owned by the same company that currently manages the RC receiver, which has in turn led to an uncertain situation, where the task of load control is not clearly defined (Ministry of Business, Innovation & Employment - New Zealand Smart Grid Forum, 2015).

This becomes evident when RC linked to hot water heaters in residential households is analysed. In New Zealand, hot water heaters are partially used for DR associated with RC. However, it is not clear how many hot water units are already connected to RC and used for DR. RC connections vary by lines company. For instance, Orion, a lines company in the Canterbury region in the South Island, heavily encourages RC and requires all hot water cylinders of 100 to 500 litres storage capacity with more than 1.2 kW power rating to be equipped and controlled with RC (Orion New Zealand Limited, 2017). The maximum potential of RC across New Zealand is thus, through regional variability in RC usage, difficult to assess. The New Zealand Smart Grid Forum estimated that 880 MW was the maximum load available for RC in 2006 (Ministry of Business, Innovation & Employment - New Zealand Smart Grid Forum, 2015). However, how much of this capacity is actually in operation is not clear. Transmitting plants are over twenty-five years old and becoming increasingly unreliable (Underhill, 2006). While RC continues to be used in New Zealand, approaches to maintenance und upgrading of RC infrastructure and the extent of usage differ regionally and influence the capability of RC to be successfully operated (Ministry of Business, Innovation & Employment - New Zealand Smart Grid Forum, 2015).

3.3.1.3 Transpower DR programmes in New Zealand

Since 2007 Transpower has conducted a variety of DR programmes (Transpower New Zealand Limited, 2018a). Transpower provides a DR programme that, in contrast to curtailable load, allows customers to react voluntarily on a DR signal to reduce electricity consumption. This programme is focused on customers with at least twenty or more kilowatts of peak demand. This indicates that residential households might not be the focus of this programme unless they can provide a community demand aggregation mechanism (Transpower New Zealand Limited, 2018b). Approved customers participating in Transpower's DR programme are informed hours before the actual DR event occurs. During this time interval, Transpower and the customer agree on a price and an available kilowatt amount to be reduced by during the DR event. In 2013, Transpower's DR programme had 134 MW of industrial customers registered. During this year, twenty DR events were successfully called (Transpower New Zealand Limited, 2014). Currently, Transpower is the only aggregator of DR in New Zealand. EnerNOC, an American-based company provided a similar service (100 MW automated DR) by focussing on industrial customers in 2012. However, these services are no longer provided by EnerNOC.

Transpower does not determine the mechanism that leads to a reduction in electricity consumption, but allows the customer to choose between the usage of stand-by generators, load curtailment, and the utilisation of batteries or alternative sources (Transpower New Zealand Limited, 2018d). In contrast to RC, the DR programme from Transpower extends the way end-users and system operators communicate with each other. This adds an additional level to this mechanism and justifies the separation from the previous section. Furthermore, Transpower's DR programme does not solely focus on hot water systems or heat pumps but enables a broader approach where the capacity is the decisive parameter, rather than the appliance. The information on Transpower's DR programmes extend the view on how DR mechanisms could be implemented and also facilitate DR scenario development, to estimate the technical potential of residential DR.

Furthermore, Lund et al. (2015) describes ancillary services in more detail and emphasises, that ancillary services are determined by the service duration they offer. This links to Fig. 2 of section 3.3.1 in this thesis.

3.3.2 Energy efficiency

WW can assist with demand peaks by reducing total demand, usually through replacing inefficient appliances with more efficient ones. In the following, the legal foundation to incorporate EE in the residential household sector is briefly presented. Two subsequent approaches for reducing electricity demand are elucidated.

Unlike DR, New Zealand has a strong commitment to EE in policy and four core sources constitute the foundation of EE policy. These sources are:

1) The Energy Efficiency and Conservation Act 2000,
2) The New Zealand Energy Strategy 2011-2021,
3) The New Zealand Energy Efficiency and Conservation Strategy 2017-2022, and
4) The Energy Efficiency and Conservation Authority's Work Programmes.

EE policy does not solely pursue efficiency of electricity use but, is also linked to goals that subsequently arise through the implementation of EE such as general business growth.

Minimum Energy Performance Standards set minimum levels of energy performance for electrical appliances in New Zealand (Energy Efficiency and Conservation Authority, 2017c; Rahman et al., 2016). These regulate the deployment of new appliances sold in New Zealand and ensure a gradual demand reduction when old appliances are replaced with newer, more efficient ones.

The Program's second component constitutes "energy labels". Energy labelling enables customers to straightforwardly compare EE and estimated energy consumption of equal electrical appliances. This has the potential for promoting a lower demand for appliances with similar attributes. New Zealand has also had a longstanding programme for supporting the insulation of residential homes (Warm Up NZ), which improves EE and also increases the potential for DR for heating and cooling appliances, due to improved thermal storage characteristics of insulated homes.

Despite the side-effects of policies around EE in New Zealand on electricity demand, until recently, policies did not recognise the potential of EE for reducing daily peak demand. In fact, EECA first mentioned the connection between DR and EE and the opportunity provided by DSM to reduce peak demand in March 2018 (Energy Efficiency and Conservation Authority, 2018). This underlines the need for analysing this potential of EE, in order to reduce daily peak demand.

4. Data & Methods

The estimation of the technical potential of residential DSM comprising of DR and EE in New Zealand, forms the core of this thesis. This study utilises a variety of data sources and methodologies to estimate both power potential and economic value of residential DSM, focussing on hot water heating, refrigeration, heat pumps, and lighting. This chapter describes these data sources and the methodologies used to estimate the potential of DSM for reducing the daily peak demand of these appliances in households, focussing on DR for hot water heating, refrigeration, and heat pumps, and EE for lighting.

The chapter is divided into five sections. The first section presents the core sources from which the data utilised in this study are drawn and defines times of peak demand. The second section describes the methodology that establishes baseline demand profiles for the key residential household appliances. This uses average seasonal household demand profiles for hot water heaters, heat pumps, refrigeration, and lighting scaled to represent the total New Zealand household population, to give 'whole of demand' values. Three DR scenarios were then applied: full load curtailment, halved load curtailment, and load shifting. The analysis conducts calculations for each individual appliance as well as for groups of appliances under these scenarios. The third section describes methodology used in developing DR scenarios and then applying them to the chosen appliances. The fourth section describes the methodology used to incorporate EE in this analysis. The final section describes the methodology used to estimate the economic value of DR and EE, based on the previously calculated energy scenarios.

Study limitations and simplifying assumptions are presented in section 6.2 and then further elucidated in Appendix 1.

The data used was drawn from six core sources (limitations of these data sets are presented in section 6.2 and in Appendix 1):

- Energy Efficiency and Conservation Authority (EECA):
    - Energy End Use Database(Energy Efficiency and Conservation Authority, 2017a)
- GREENGrid project:
    - GREENGrid dataset (Anderson, Eyers, Ford, Giraldo Ocampo, Poeniamina, et al., 2018)
- Building Research Association of New Zealand (BRANZ):
    - Heat Pumps in New Zealand (SR329)(Burrough, Saville-Smith, & Pollard, 2015)
    - Heat Pumps in New Zealand Houses (CP152)(Burrough, 2010)
    - Energy Use in New Zealand Households (SR155)(Isaacs et al., 2006)
    - Warm, dry, healthy? Insights from the 2015 House Condition Survey on insulation, ventilation, heating and mould in New Zealand houses (SR372)(White & Jones, 2017)
    - Hot water over time – the New Zealand experience (No. 132)(Isaacs, Camilleri, & French, 2007)
- Statistics New Zealand Tatauranga Aotearoa:
    - Households in New Zealand (Stats NZ Tatauranga Aotearoa, 2014a), (Stats NZ Tatauranga Aotearoa, 2014b)
- Electricity Authority (EA):
    - Electricity generation trends (Electricity Authority, 2018c).
- Department of Industry and Science
    - Residential Baseline Study (RBS) for New Zealand 2000-2030 (Department of Industry and Science, 2015)

The Energy End Use Database from the Electricity Authority was used in chapter 2 to identify sources of energy consumption in New Zealand. In this section, it is used to compare two methods for estimating the total New Zealand energy consumption for heat pumps, electric hot water heaters, and refrigerators in residential households (See Section 4.2).

Electricity demand profiles of forty New Zealand households serve as the foundation of calculations and were measured by GridSpy monitors in the context of the GREENGrid project (Stephenson et al., 2018). GridSpy recorded electricity power on a one-minute granularity for each power circuit over several years. These demand profiles provide baseline time-of-day load profiles for each appliance by season (see Section 4.2).

The Building Research Association of New Zealand reports on heat pumps and hot water heaters in residential households and the Census 2013 household data were used to scale heat pump and electric hot water appliance demand profiles to the total number of appliances in New Zealand (see Section 4.2).

The Electricity Authority data was used to compare the baseline and DR scenarios with measured overall electricity generation to establish the extent to which the scenarios represent change to overall system demand.

The Residential Baseline Study (RBS) provides the foundation for estimating EE forecasts and focuses on lights in residential households. A thorough explanation of how the RBS is incorporated into this work is provided in section 4.4.

4.1 Definition of peak times

Fig. 11 of section 3.2 demonstrates that electricity generation increases at 06:00 in both summer and winter and decreases after 09:00 until 10:00, especially during winter. The evening peak occurs at 17:00 and lasts until 21:00, while the shape of the peak in winter is much more defined than in summer. Summer and winter in this example were chosen to present the bandwidth of times of peak demand. The analysis considers spring and autumn as well.

The analysis addresses four seasons for each appliance, as described in Table 2:

Table 2: Determination of seasons

Season	Definition
Spring	01.09-30.11
Summer	01.12-28.02
Autumn	01.03-31.05
Winter	01.06-31.08

For the purpose of this research, intervals of daily demand profiles are defined as:

Table 3: Daily time intervals

Time interval	Time
Off Peak 1	21:30-05:59
Morning Peak	06:00-10:29
Off Peak 2	10:30-16:59
Evening Peak	17:00-21:29

It should be noted that each interval is set to the start of the individual half hour. Thus, for example, 10:29 is allocated to the morning peak. The table therefore encompasses the whole twenty-four hours of the day. For simplicity the same number of half-hours for both morning and evening peak is assumed, and the analysis does not distinguish between seasons. These allocations are based on the national electricity demand profile of section 3.2.

4.2 Developing half-hourly baseline demand profiles

The calculations used to estimate the technical potential of DR require half-hourly appliance load data as a baseline, from which DR scenarios can be calculated. The same prerequisite is valid for the analysis of EE. The analysis extracted half-hourly load data for hot water heaters, heat pumps, and lights from forty households in the GREENGrid dataset (Anderson et al., 2018) and aggregated them to produce a mean seasonal (average over ninety days) load profile over all households for each appliance technology except refrigeration. Refrigerators were not monitored by the GREENGrid project and a flat profile to estimate the technical potential of DR is assumed.

These mean profiles are then scaled using Census 2013 household counts and BRANZ data on appliances prevalent in both rental and owner-occupied premises. This enables the estimation of total national energy use for heat pumps, hot water, and refrigeration on a seasonal and yearly basis. Finally, the study compares these results with 2015 EECA data on delivered electricity, in order to validate the calculations. For residential lights, and the associated forecast on the uptake of more energy efficient lighting, the analysis utilises data from the RBS to scale the average load profile. The following sections describe this process in detail.

The GREENGrid monitored data incorporates electricity power outliers for hot water, heat pump and lighting (Anderson al., 2018). This work adopts the process of action suggested in the aforementioned report in order to not overestimate results. In particular, a household with negative power values, labelled as “rf_46” was removed from the analysis in this work.

There are other potential limitations associated with the GREENGrid data set. The chosen sample size is very small (40 households) and biased towards newer homes and higher socio-economic households. Furthermore, not many heat pumps were monitored and there is possible circuit mis-labelling, which influences the power values in the data set. Limitations and assumptions that are incorporated in this thesis are further highlighted in section 6.3.

4.2.1 Statistical limitations

This work utilises mean electricity demand profiles from the GridSpy monitored appliances in residential households. Using the mean necessarily involves loss of variability, and an analysis of the original data, before calculating the mean, shows the bandwidth lost by using the mean.

Boxplots incorporate the original data set on a one-minute granularity. Fig. 16 depicts these boxplots without taking any averages for hot water load in winter. Each point represents average hot water power demand for every minute. It is clearly visible that a variation in monitored load increases at peak demand, especially at around 07:00 in the morning and 19:00 in the evening, leading to a significant variation between the first and third quartile of the boxplot. Furthermore, minimum and maximum are more stretched compared to off-peak times. The darker the dots above the maximum the more data points were monitored on this power level. Generally, a lot of outliers were monitored reaching up to 3 kW, while the calculated mean during peak demand varies between 200 and 600 W.

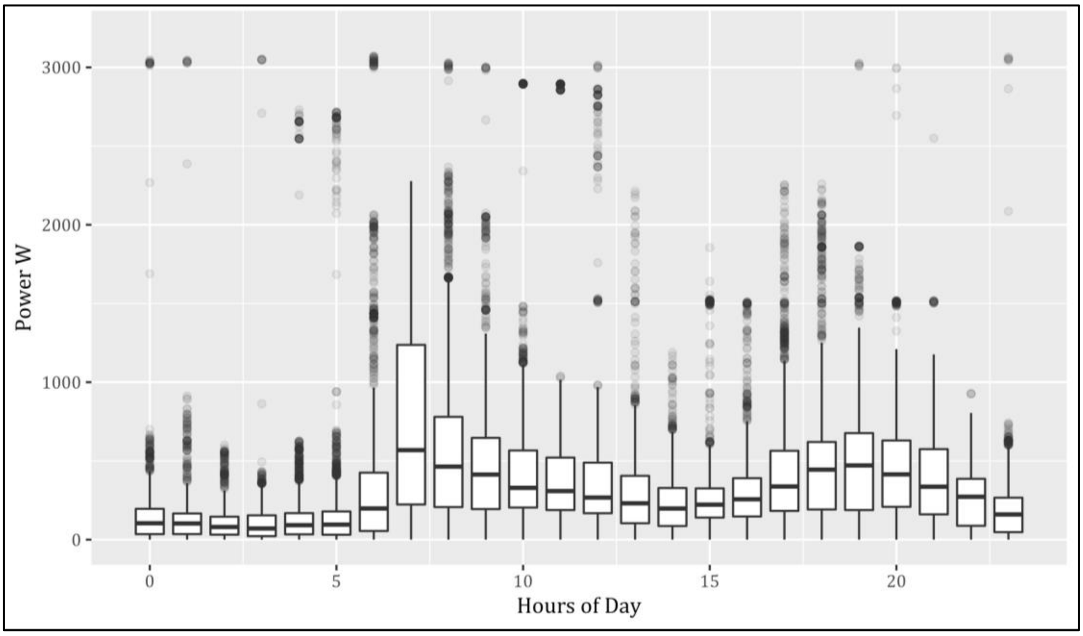


Fig. 16| Hot water load boxplot one-minute granularity

This view on load distribution can be extended by analysing histogram and density plots. Fig. 17 depicts a histogram of the winter morning peak for hot water load, scaled national demand in MW by using the method described in section 4.2.3. The figure considers all households on each minute recorded. The plot shows that most of the recorded demand was zero or near to zero (most of hot water cylinders turned off) during the winter morning peak for hot water. At times of active hot water cylinders (indicated by positive number of observations 'count'), observations show a demand of 2,000 to 4,000 MW.

A density plot incorporates data from the same half hour of peak demand. The load distribution is extended by the mean, depicted in the dotted line. As shown in Fig. 18, the mean is estimated to be approximately 1,200 MW (or 600 MWh per half-hour) at maximum peak demand. However, the density plot clearly exhibits that the mean does not represent the data set very well.

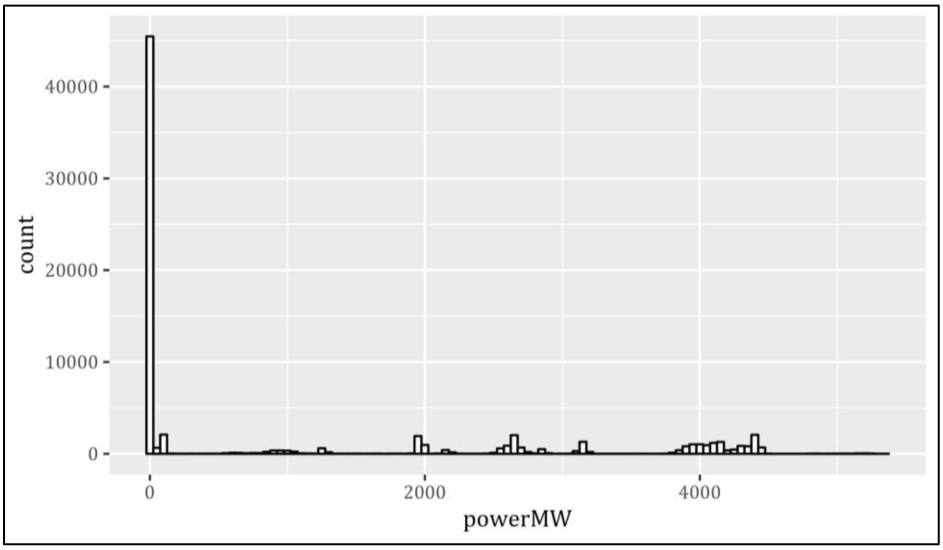


Fig. 17| Winter morning peak total New Zealand equivalent; histogram for hot water at half-hour of peak demand

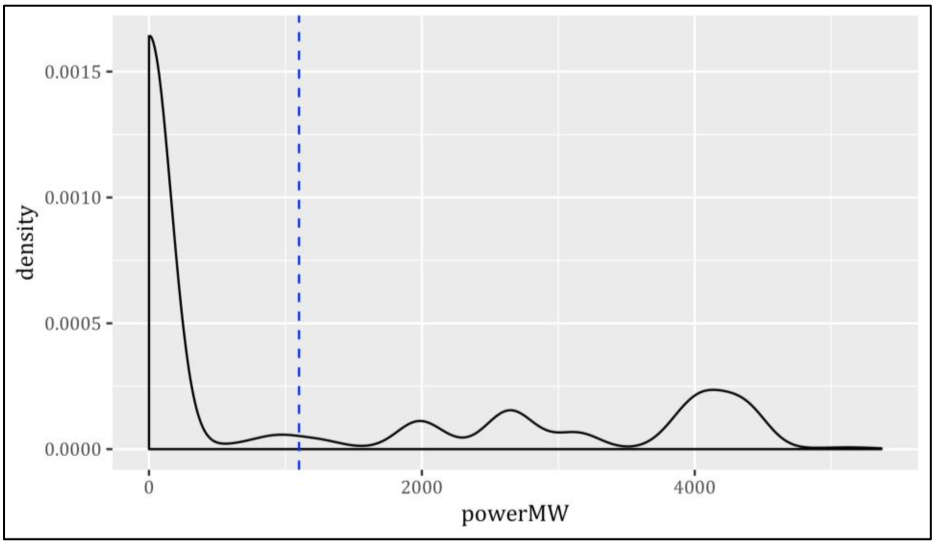


Fig. 18| Winter morning peak total New Zealand equivalent; density for hot water at half-hour of peak demand

While this shows that incorporating the full data set rather than averages would have benefits, there is also a reason to focus on high electricity demand. Applying DR on consumers premises that embrace a high electricity demand at around 4,000 MW affects comparatively fewer consumers than applying DR mechanisms such as RC across the electricity network. This implies there may be benefits to considering high electricity demand (without using averages) in contrast to whole-population means as used in this study. This could be the approach taken in a future study.

4.2.2 Heat pumps

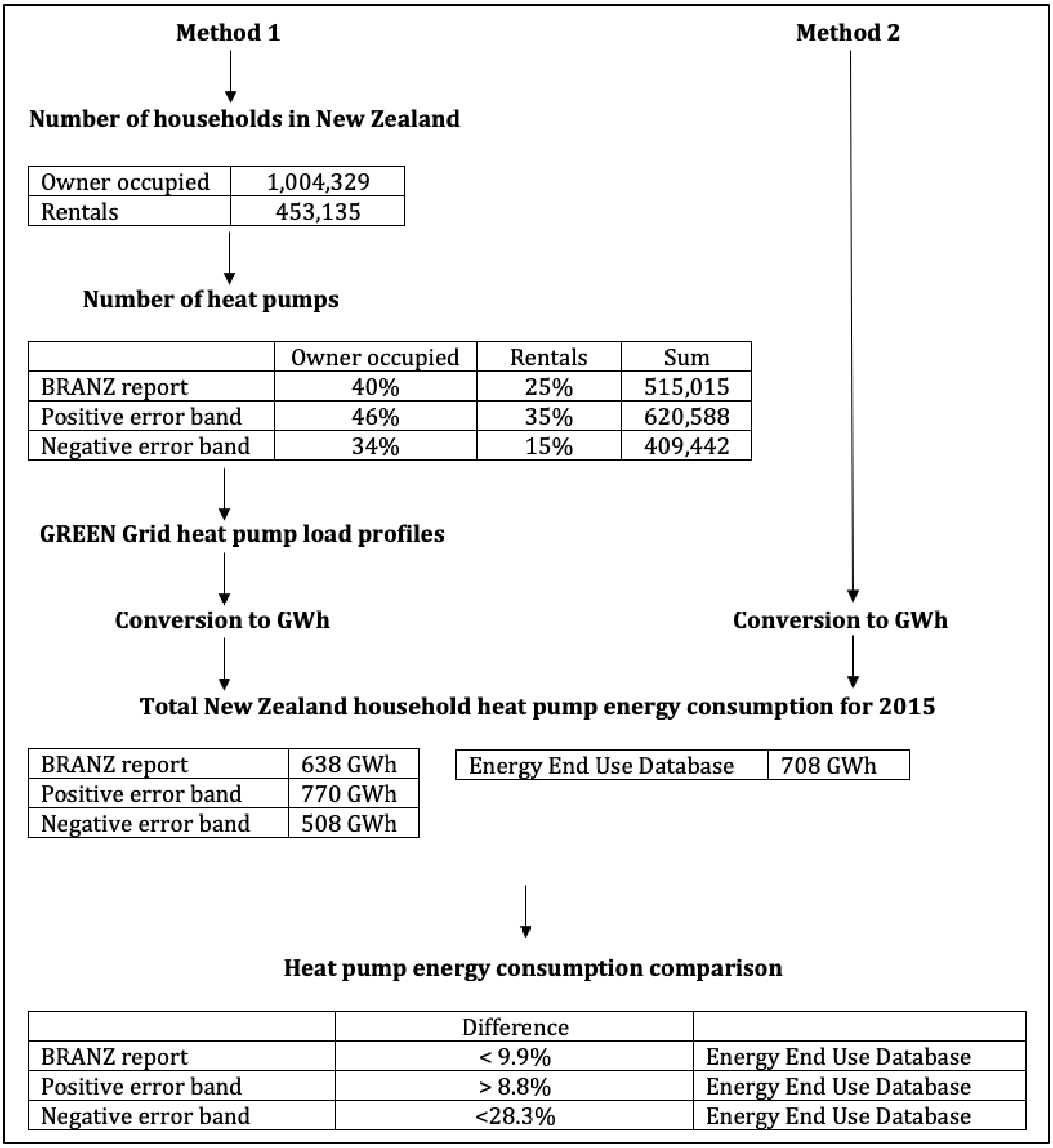
Heat pump energy consumption is assessed on the basis of:

1. BRANZ reports (Burrough, 2010; Burrough et al., 2015; Isaacs et al., 2006; White & Jones, 2017) combined with GREENGrid data (Anderson et al., 2018), Census 2013 data on households (Stats NZ Tatauranga Aotearoa, 2014a, 2014b) and

2. EECA information on delivered electricity (Energy Efficiency and Conservation Authority, 2017a).

Two parallel methods were used from these different data sets. Method One utilises BRANZ, GREENGrid and Census 2013 data to scale heat pump electricity demand from a one-minute granularity average household profile per season to a total New Zealand profile of average energy consumption per half hour and season. The BRANZ reports distinguish between owner-occupier and rental household tenure and Census 2013 data on the prevalence of such households was used to estimate the number of heat pump appliances in New Zealand. BRANZ information included a margin of error as they were based on survey results conducted in 2010 and 2011. For occupied households the error band was +/-6 % while for rental it was +/-10 per cent. This uncertainty was reflected in the calculations and the effects of using these upper and lower boundaries are shown in Fig. 19.

Method Two simply utilises the EECA 2015 total figure of delivered electricity for heat pumps in New Zealand. As can be seen, Method One estimates the total energy consumption per year for heat pumps in New Zealand as 638 GWh and Method Two suggests a 10% lower energy consumption per year based on the central estimate (638 GWh vs 708GWh), although this may be higher or lower, as indicated by the error margins. To prevent overestimation, the study in this thesis utilises the lower total energy consumption estimate (638 GWh) based on the BRANZ reports in subsequent calculations. Note that BRANZ and Census data were recorded before 2015, but this thesis assumes that the information is likely to be consistent with monitored data from 2015.



Owner occupied	1,004,329
Rentals	453,135

	Owner occupied	Rentals	Sum
BRANZ report	40%	25%	515,015
Positive error band	46%	35%	620,588
Negative error band	34%	15%	409,442

BRANZ report	638 GWh
Positive error band	770 GWh
Negative error band	508 GWh

Energy End Use Database	708 GWh

	Difference	
BRANZ report	< 9.9%	Energy End Use Database
Positive error band	> 8.8%	Energy End Use Database
Negative error band	<28.3%	Energy End Use Database

Fig. 19| Heat pump energy consumption comparison

4.2.3 Hot water heaters

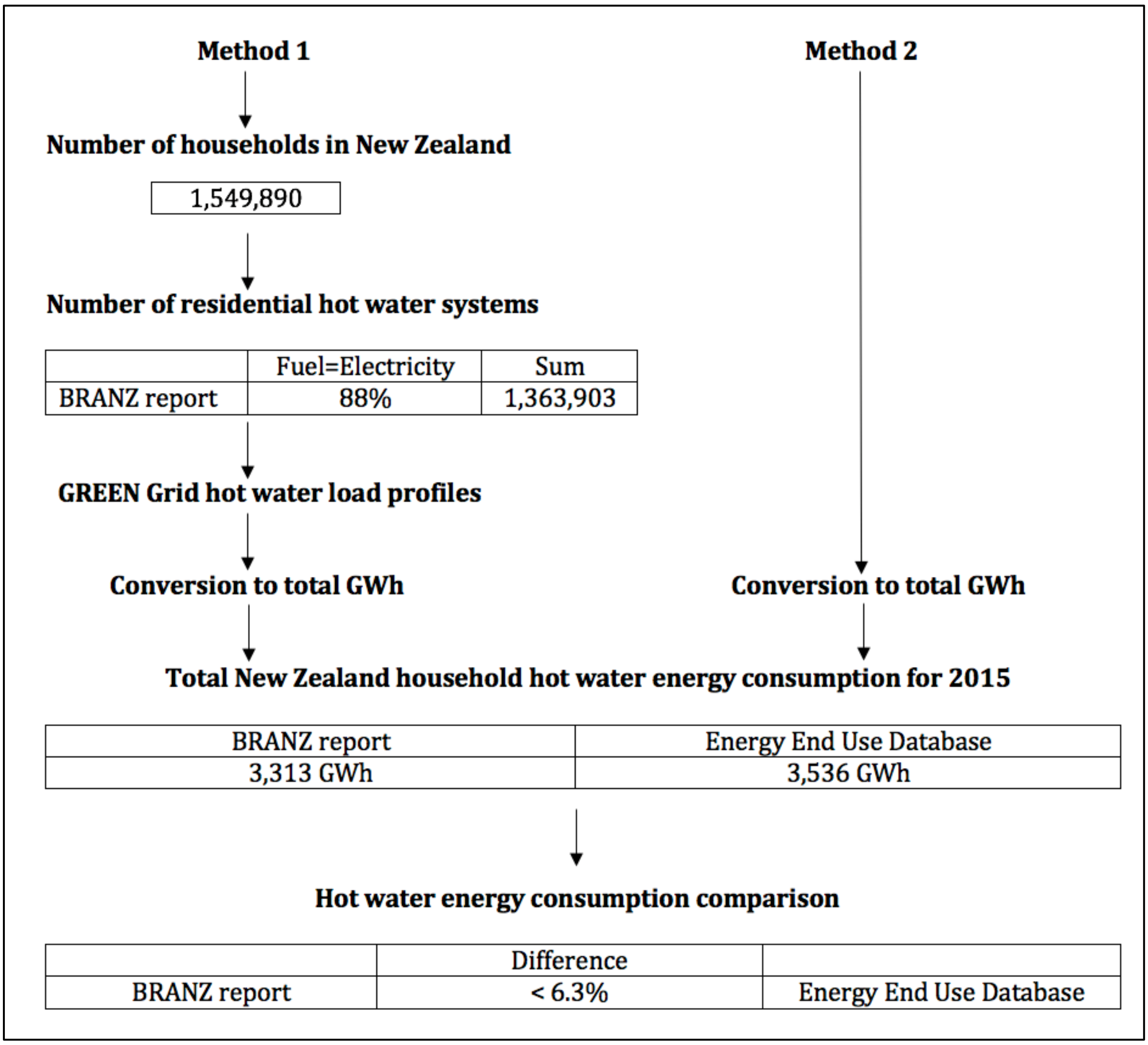
Processing hot water heater energy consumption has also involved two methods. The comparison of hot water heater energy consumption draws on the methodology described for Heat Pumps. Fig. 20 compares Method One and Method Two based on:

1) BRANZ report (Isaacs et al., 2007) combined with GREENGrid data (Anderson, Eyers, Ford, Giraldo Ocampo, Poeniamina, et al., 2018), Census 2013 data on households (Stats NZ Tatauranga Aotearoa, 2018) and

2) EECA information on delivered electricity (Energy Efficiency and Conservation Authority, 2017a).

However, Method One differs from the estimation utilised in the heat pump energy comparison by using BRANZ data on the proportion of electricity-based hot water heaters in New Zealand (88%). In contrast to information on heat pumps, BRANZ reports on hot water heaters do not provide margins of error as they are based on Census data.

After converting the average seasonal daily hot water electricity demand profile from a one-minute granularity to an average seasonal daily hot water energy consumption profile with a half-hour granularity, the analysis scales the energy consumption to the total of New Zealand and compares this with the figure generated by EECA. A 6% lower energy consumption (3,313 GWh per year) in Method One compared to Method Two is identified. As before, subsequent calculations utilise the lower total energy consumption produced by method one to prevent overestimation.



	Fuel=Electricity	Sum
BRANZ report	88%	1,363,903

BRANZ report	Energy End Use Database
3,313 GWh	3,536 GWh

	Difference	
BRANZ report	< 6.3%	Energy End Use Database

Fig. 20| Hot water heater energy consumption comparison

4.2.4 Refrigeration

The GREENGrid dataset does not provide sufficient data to replicate the previous methods used to produce refrigeration profiles. Instead, the analysis incorporates an assumed flat energy profile, using the total energy consumption of 2,074 GWh provided by EECA for household refrigerators in 2015. The refrigeration profile, therefore, does not vary during peak and non-peak times, but shows a constant profile (240 MW throughout the year). In this case, Census derived estimates of household numbers in the different tenure types are used to scale the data appropriately.

Please note that the flat profile will not be accurate, as summer and winter loads are likely to vary, as well as loads associated with thermal loss when fridge doors are opened.

However, this data was not available, and this first cut is the best possible estimate at this point.

4.2.5 Lighting

The methodology involved the development of half-hour demand profiles for lights in New Zealand households, and differs from the aforementioned appliances. This section explains the methodology used for estimating the power potential and of EE.

Similar to heat pumps and hot water heaters, lights were monitored in the GREENGrid project. However, as DR is not suitable for lighting, the scaling of the average load profile for lights considers the potential for adaption of energy efficient lighting over time and, thus, requires data for more than one year. An attempt to forecast heat pump and hot water profiles for future years was not conducted. This is because:

- Heat pumps and hot water heaters are suitable for DR;
- There are less EE gains through progress in these technologies, compared to lighting;
- The Residential Baseline Study does not present stock developments of heat pumps and hot water heaters as well as it does for lighting.

The analysis in this thesis utilises the data provided by the RBS to estimate the total average energy consumption for lighting in New Zealand households for lights. The forecast incorporates RBS data (Department of the Industry and Science, 2015) from 2015 to 2029 at an interval of every second year. Energy potential and economic value for EE in this work are thus estimated for 2015, 2017, 2019, 2021, 2023, 2025, 2027 and 2029.

The following equations underpin the analysis performed with lighting data from the RBS.

$$\bar{E}_{2015}^{EECA} \neq \bar{E}_{2015}^{RBS} \quad \text{Eq. (1)}$$

delineates that the average energy consumption labelled by $\bar{E}$ for lighting in residential households showed that data provided by EECA and the Residential Baseline Study (RBS) did not match in the baseline year 2015. The following equations generate a scaling factor which enables us to utilise the EECA average energy consumption (in 2015) for the RBS and its associated forecast. This explanation is divided into four parts.

1) Calculating average energy consumption based on per-unit consumption and stock:

The average energy consumption in the RBS depicted by $\bar{E}_j^{RBS}$ for each jth year analysed is calculated by building the sum over the average energy consumption for every technology t analysed for each jth year. This can be written as:

$$\bar{E}_j^{RBS} = \sum_t \bar{E}_{jt}^{RBS} \quad \text{Eq. (2)}$$

while $\bar{E}_{jt}^{RBS}$ is the product of energy consumption (kWh) per unit for each t analysed labelled by e_t^{RBS} and the average stock for every t in each jth year analysed.

$$\bar{E}_{jt}^{RBS} = e_t^{RBS} \times \bar{S}_{jt}^{RBS} \quad \text{Eq. (3)}$$

clarifies this process.

Technologies incorporated into an analysis of EE in this work are:

Table 4: Analysed lighting technologies

Lighting technology	**Annual energy consumption (kWh) per unit**[2]
Incandescent	43.7
Halogen	30.6
Electric low voltage halogen	29.9
Linear fluorescent	24.8
Compact fluorescent	8.1
Light-emitting diode	3.0

2) Assuming EECA and RBS stock estimations are identical:

The equations mentioned above can be applied on EECA data and are depicted in the following two equations

$$\bar{E}_j^{EECA} = \sum_t \bar{E}_{jt}^{EECA} \quad \text{Eq. (4)}$$

and

---

[2] Based on RBS data on average stock proportions and EECA energy consumption data for 2015.

$$\bar{E}_{jt}^{EECA} = e_{t}^{EECA} \times \bar{S}_{jt}^{EECA} \quad \text{Eq. (5)}$$

where the units and variables stay the same as described in Equation 2 and Equation 3.

However, it is assumed that the average stock is equivalent for EECA and RBS. The following equations depict this assumption.

Assumption 1:

The average stock for EECA and RBS is equivalent and depicted by

$$\bar{S}_{jt}^{EECA} = \bar{S}_{jt}^{RBS} \quad \text{Eq. (6)}$$

where $\bar{S}_{jt}^{EECA}$ is the EECA average stock in each jth year for every t analysed and equivalent to the average stock of the RBS labelled by $\bar{S}_{jt}^{RBS}$.

3) Estimating energy proportions for every jth year and t analysed:

A third step estimates the energy proportion in the RBS for every jth year and t analysed. This energy proportion is labelled by P_{jt}^{RBS} and calculated with

$$P_{jt}^{RBS} = \frac{\bar{E}_{jt}^{RBS}}{\bar{E}_{j}^{RBS}} \quad \text{Eq. (7)}$$

while P_{jt}^{RBS} is calculated by dividing the average energy consumption for each jth year and t analysed labelled by $\bar{E}_{jt}^{RBS}$, with the average energy consumption for each jth year labelled by $\bar{E}_{j}^{EECA}$.

The same process can be applied on EECA data where the units and labels remain the same and depicted by

$$P_{jt}^{EECA} = \frac{\bar{E}_{jt}^{EECA}}{\bar{E}_{j}^{EECA}}. \quad \text{Eq. (8)}$$

Assuming that the energy proportions for each jth year and t analysed are identical for EECA and RBS is visualised through

Assumption 2:

$$P_{jt}^{EECA} = P_{jt}^{RBS}. \quad \text{Eq. (9)}$$

4) The forth step finalises the equations to calculate the scaled average energy consumption for each jth and t analysed:

Assuming that the energy proportions of EECA and RBS are identical this can be written as:

$$\frac{\bar{E}_{jt}^{RBS}}{\bar{E}_{j}^{RBS}} = \frac{\bar{E}_{jt}^{EECA}}{\bar{E}_{j}^{EECA}} \quad \text{Eq. (10)}$$

This equation can be transformed into

$$\bar{E}_{jt}^{EECA} = \frac{\bar{E}_{j}^{EECA}}{\bar{E}_{j}^{RBS}} \times \bar{E}_{jt}^{RBS} \quad \text{Eq. (11)}$$

to depict the average energy consumption for each *j*th year and t analysed labelled by $\bar{E}_{jt}^{EECA}$. $\bar{E}_{jt}^{RBS}$ in this case can be derived from 1) and extends the equation from above to:

$$\bar{E}_{jt}^{EECA} = \left(\frac{\bar{E}_{j}^{EECA}}{\bar{E}_{j}^{RBS}} \times e_{t}^{RBS}\right) \times \bar{S}_{jt}^{RBS} \quad \text{Eq. (12)}$$

where $\left(\frac{\bar{E}_{j}^{EECA}}{\bar{E}_{j}^{RBS}} \times e_{t}^{RBS}\right)$ is the scaling factor needed to estimate the average EECA energy consumption based on the RBS forecast. Finally, the scaling factor e_{t}^{EECA} is determined to be

$$e_{t}^{EECA} = \frac{\bar{E}_{j}^{EECA}}{\bar{E}_{j}^{RBS}} \times e_{t}^{RBS}. \quad \text{Eq. (13)}$$

Applying these calculations enables an analysis of EE of residential household lighting for every *j*th year. The values in the second and third column of Table 5 are drawn from the equations mentioned above, while the number of households for every *j*th year are forecast and given by the RBS. These numbers are used to estimate the total residential household energy consumption for lighting in GWh per year. This enables us to perform a scaling process for every *j*th year analysed, utilising the average household load profile for lights monitored by the GREENGrid project and estimated lighting energy consumption from EECA. This scaling process is adopted from the previous appliances. However, instead of one year, the scaling process is conducted for 8 years (2015-2029 for every second year).

Table 5: Lighting energy forecast

Year	Lighting kWh per year (per household)	Lighting GWh per year (total NZ)	Number of households
2015	878	1,577	1,796,331
2017	818	1,501	1,833,349
2019	731	1,366	1,868,507
2021	628	1,196	1,903,664
2023	530	1,026	1,935,926
2025	442	871	1,968,188
2027	367	734	1,998,382
2029	307	622	2,026,508

4.3 DR scenarios

DR scenarios analysed are based on the DR mechanisms described in section 2 (load shifting and load curtailment). These scenarios provide an *order-of-magnitude*, an approximate estimation, and incorporate both individual demand profiles and appliance aggregation. The analysis incorporates 4 simple scenarios based on Fig. 21 (i.e. load curtailment (Scenario 1), load shifting (Scenario 3), and the response to congestion periods (Scenario 4)) to facilitate comprehension of the analysis. Scenarios 1-3 are based on the work conducted by Bronski et al. (2015), Palmer et al. (2013), and Dyson et al. (2014), as highlighted in section 2.2. Scenario 4 was developed in this study and is not related to the aforementioned studies.

Please note that this study does not consider second order effects such as consequential system price changes under these scenarios, but utilises market information measured without the implementation of DR scenarios. Furthermore, the analysis utilises a simplifying assumption under Scenario 3 that shifts the demand to the prior time-period. This load shifting could, for example, involve pre-heating and pre-cooling prior to the time of peak demand. The following section presents and describes these three DR scenarios depicted in

Please note that Scenarios 1 and 2 are simply used to quantify the demand that can be shifted at peak times and are unlikely to be implemented at that scale.

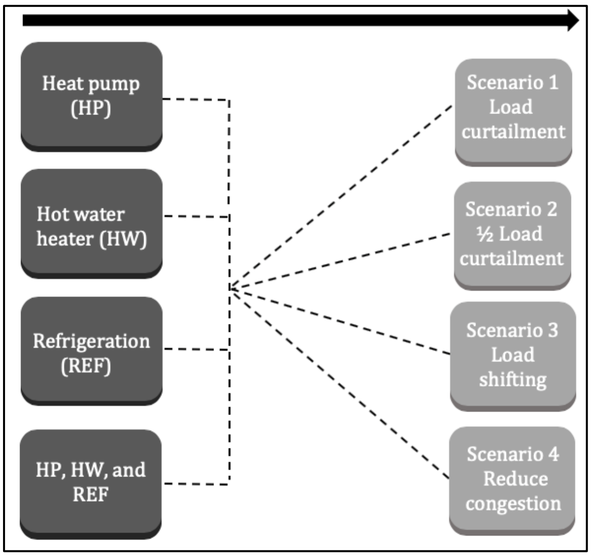


Fig. 21| Appliance and scenario visualisation

4.3.1 Scenario 1: Load curtailment to zero

This first DR scenario assumes a full load curtailment during times of peaks, without any other adjustments in the periods of Off Peak 1 and Off Peak 2. This is consistent with the study from Gils (2014). Electricity demand is set to zero at peaks. As mentioned in the introduction, Scenarios 1 and 2 are simply used to quantify the demand that theoretically can be shed at peak times and are unlikely to be implemented. Fig. 22 exhibits the idea of Scenario 1.

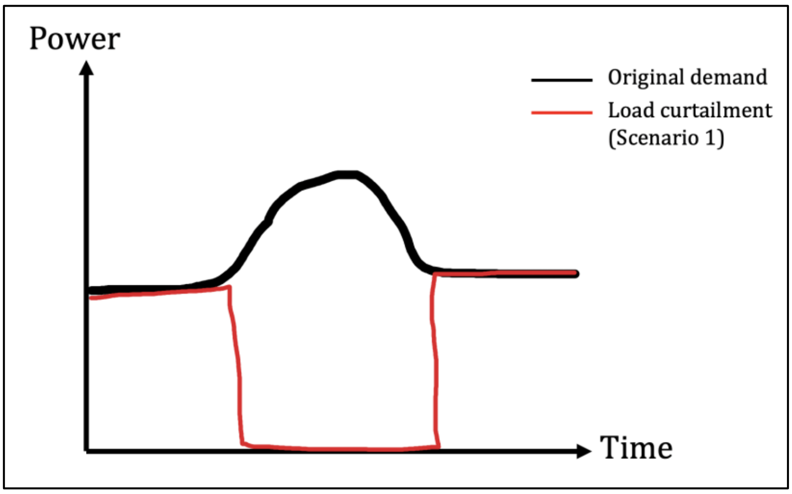


Fig. 22| Scenario 1: Load curtailment to zero

4.3.2 Scenario 2: Halved load curtailment

The second scenario is similar to the approach of Scenario 1 but instead decreases electricity demand at peaks so half of the original energy consumption is attributed to the new energy consumption profile. Studies reviewed in chapter 2 do not conduct halved load curtailment. This thesis does, however, incorporate this scenario and suggests potential for a range of curtailment options. There are no electricity demand modifications in the time interval of Off Peak 1 and Off Peak 2. Halved load curtailment is applied in an example load profile in Fig. 23.

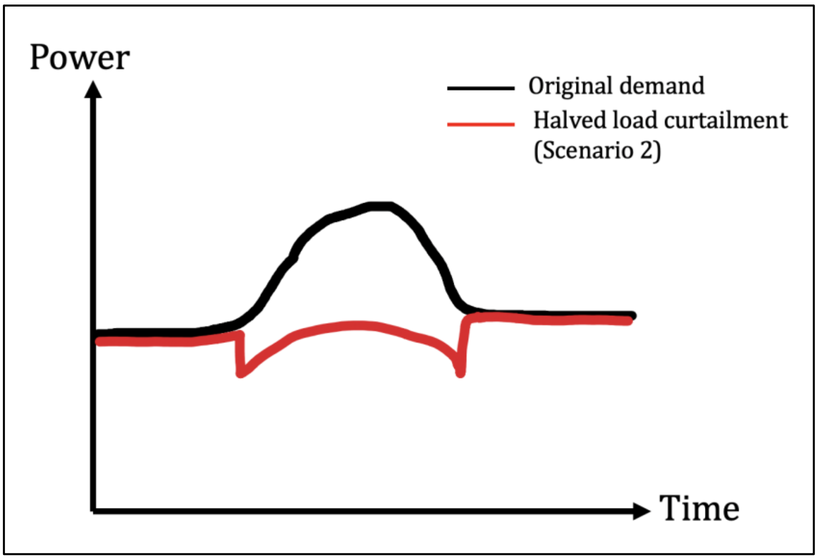


Fig. 23| Scenario 2: Halved load curtailment

4.3.3 Scenario 3: Load shifting

Scenario 3 pursues the approach of load shifting. Load shifting, is the more realistic scenario in this thesis as it does not solely reduce load but shifts the load to off-peak periods. Scenario 3 (load shifting) can be found in many studies that focus on the potential of DSM connected to residential household appliances such as Palmer et al. (2013), Arteconi et al. (2013), Dyson et al. (2014), and Bronski et al. (2015). Electricity demand at peak times is shifted to the prior time period of Off Peak 1 or Off Peak 2, respectively. Demand for individual appliances in the morning peak is attributed to Off Peak 1 while the demand in the evening peak is incorporated in the interval of Off Peak 2. The demand is curtailed at peaks and is equally spread over the individual associated off-peak period. This leads to an increase in demand during off-peak times while the demand at peak times shows the same pattern as load curtailment under Scenario 1. Fig. 24 clarifies this increased electricity demand during off-peak periods.

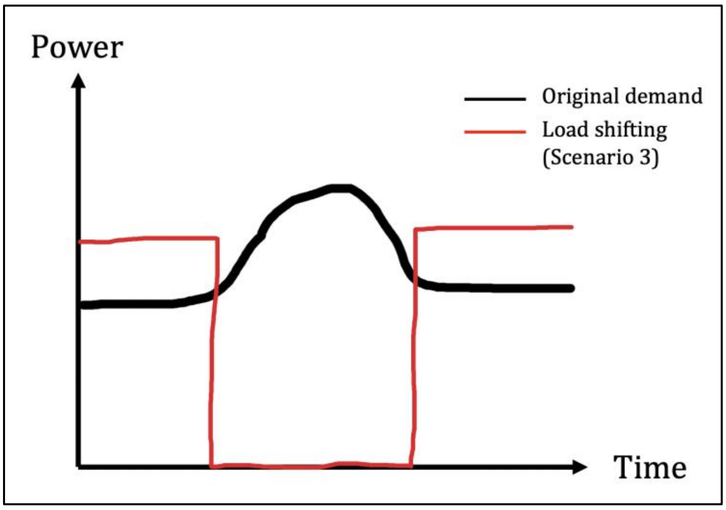


Fig. 24| Scenario 3: Load shifting

4.3.4 Scenario 4: Reduce congestion

A fourth scenario analyses congestion events and curtails load at these times. In contrast to load shifting, Scenario 4 affects customers only for approximately 100 hours per year (see section 4.5.2) and is, for the purpose of this thesis, only incorporated for the combined aggregation of hot water heaters, heat pumps, and refrigeration. The incorporation of Scenario 4 has the benefit of curtailing load only at times when network congestion is apparent. Furthermore, Scenario 4 is used to estimate the power potential and economic value of this curtailment and is compared with the results from shifting load under Scenario 3.

The potential demand curtailment of each DR scenario is combined with electricity generation data from the Electricity Authority in order to determine the proportion of electricity demand and generated electricity during relevant peak times.

4.4 Energy efficiency

In contrast to heat pumps, hot water heaters, and refrigerators, storage ability cannot be attributed to lighting. DR scenarios as elucidated in the previous sections are thus not applied to the average lighting demand profile. The analysis of EE potential instead shows the development of electricity demand and economic parameters over the analysed years for the seasons portrayed in Table 2 and thus reveals information about energy and economic savings based on the implementation of more efficient lighting technologies over time.

4.5 Economic analysis method

The economic value of residential DR and EE is based on power potential. DR mechanisms constitute a significant part of the economic analysis and real-time pricing (spot market) and time-of-use pricing (critical peak pricing in form of CPD charges) are utilised. For the forecast of economic developments concerning EE of residential lighting, the study assumes that the economic parameters utilised to estimate the economic DR potentials do not change over the years analysed in the EE analysis (see Assumption 2 in Appendix 1). Recent studies have incorporated two components in the economic analysis. These components are 1) real-time pricing and 2) the cost to build additional distribution infrastructure to meet peak demand (Bronski et al., 2015; Torriti et al., 2010).

The economic analysis in this thesis is divided into two parts. The first part highlights the economic value solely based on spot market prices (real-time pricing) for one year, while the second part incorporates the combination of CPD charges and spot market prices. The second part goes beyond the analyses mentioned in the literature review, as monitored data of congestion periods and its associated charges is utilised. However, the cost for additional distribution of infrastructure to meet peak electricity demand is not considered.

The analysis comprises of data from the following core sources in addition to the sources mentioned at the beginning of chapter 4:

- Electricity Authority (EA):
    - Wholesale energy prices (Electricity Authority, 2018a)
- Aurora Energy Limited:
    - CPD charges (Comm. Dev. Mgr., 2018)

4.5.1 Spot market prices

Daily variability in spot market electricity prices is shown in Fig. 25. This covers the time frame of 01/09/2016 to 31/08/2017 and builds a one-year database with half-hourly intervals for the following five regions:

- Upper North Island
- Central North Island
- Lower North Island
- Upper South Island
- Lower South Island

Fig. 25 portrays average half hour spot market prices for each season and incorporates one year of data on a half hourly basis. The Electricity Authority provides price information for five different regions in New Zealand. Spot market prices during spring and summer increase early in the morning until 8:00. The regional price differences are not considerable, but on an average day in summer, the Lower South Island represents the lowest prices per MWh. The average maximum price per MWh takes on a value of $50 in both spring and summer.

Regional differences in electricity demand are neglected in this analysis, as explained in Appendix 1: Assumptions. Taking a similar approach to the estimation of the power potential of DR, a seasonal average profile of spot market prices (average over all regions) is built to estimate the economic value of DR and does not distinguish between regions in the final daily average spot market price per half hour and season.

Autumn and winter constitute generally higher spot market prices than spring and summer. Peak time becomes somewhat identifiable in the average prices per MWh in the morning hours from 07:00 to 09:00, and in the evening hours from 18:00 to 20:00. While there is no distinction among average prices between regions in autumn, differences between regions in winter become visible. The Upper South Island has the highest average price per MWh in winter, followed by the Lower South Island with prices up to $150 per MWh.

After adjusting the energy consumption based on the DR scenarios, average spot market prices (no regional consideration) are applied to determine the change in total price over the year from the baseline. Under Scenario 1, the energy consumption of the appliances is set to zero during peak time periods and reduces the cost to zero during these periods. Halving the load at peaks under Scenario 2 halves the baseline cost at peaks. Load shifting under Scenario 3 assumes no cost at peaks, but considers the increased energy consumption in the prior time interval and, therefore, increased cost during off-peaks.

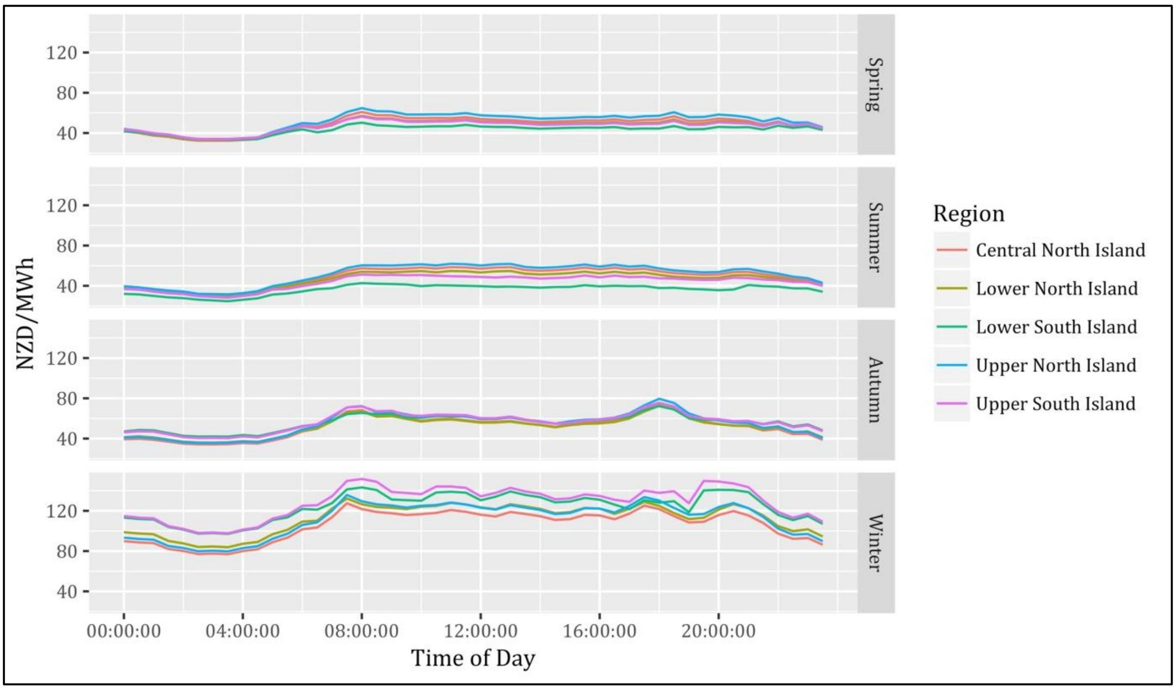


Fig. 25| Average spot market prices

Source: Based on (Electricity Authority, 2018e).

4.5.2 Congestion period demand charges

Spot market prices represent only one major component of the total electricity price for customers. A further essential price component is portrayed in CPD charges. The second part of the economic analysis thus considers CPD charges for commercial customers based on data provided by Aurora Energy Limited, along with spot market prices from the Electricity Authority. As mentioned in section 3.3.1, CPD charges are currently charged to commercial customers only. For residential customers, this charge is incorporated into lines charges and the electricity price per kWh and is thus not separately displayed. CPD charges are approximately equivalent to the cost of constructing another kW of capacity, and are a useful proxy for the value of DR to lines companies (Michael W. Jack et al., 2016). CPD demand denotes the average load across one year at CPD events in kW per household. This demand constitutes the basis for CPD charges. The higher the CPD demand at CPD events, the higher the cost.

Aurora Energy provides data on CPD events from the years of 2012 to 2016. CPD events ranged from 1-30 minutes per half hour. This information is used to calculate the probability of CPD events, and, connected with appliance demand data, the average kW of each appliance at CPD. However, due to a lack of data from other regions, the analysis does not consider regional variation in these charges. CPD charges are determined by using the following formulas to calculate the **average demand** (in kW) during CPD periods

$$\overline{D}_{CPD} = \frac{\sum_{j=1}^{j=365} \sum_{i=1}^{i=48} h_{ji} D_{ji}}{\sum_{j=1}^{j=365} \sum_{i=1}^{i=48} h_{ji}} \quad \text{Eq. (14)}$$

where h_{ji} is the number of CPD hours on the jth day in the half hour period labelled by i and D_{ji} is the demand on the jth day (in kW) in the half hour period labelled by i. Note many of the h_{ji} will be zero as there are only $\sim$100 CPD hours per year. As mentioned in section 5.1 the study utilises an average energy consumption profile over each season. In this case, the above equation can be simplified to

$$\overline{D}_{CPD} = \frac{\sum_{i=1}^{i=48} \left(H_i^W D_i^W + H_i^A D_i^A \right)}{\sum_{i=1}^{i=48} \left(H_i^W + H_i^A \right)} \quad \text{Eq. (15)}$$

where

$$H_i^A = \sum_{j=A} h_{ji} \quad \text{Eq. (16)}$$

and

$$H_i^W = \sum\nolimits_{j=W} h_{ji} \quad \text{Eq. (17)}$$

are the number of CPD hours in each half hourly interval *i* summed over all the 90 days of the season. In this equation D_i^A and D_i^W are the average demand (in kW) in each of the 48 half hour intervals for the autumn and winter profile, respectively. Note that only autumn and winter are included in this sum, as the study assumes that the CPD hours in all other seasons are zero. This assumption is supported by Aurora data, which takes monitored CPD events from 2012 to 2016 into account (M. Mason, personal communication, October 10, 2018).

Another approach to calculating $\overline{D}_{CPD}$ incorporates the probability of CPD events. In this approach equation two becomes

$$\overline{D}_{CPD} = \sum_{i=1}^{i=48} \left(P_i^W D_i^W + P_i^A D_i^A\right) \quad \text{Eq. (18)}$$

where

$$P_i^A = \frac{H_i^A}{\sum_{i=1}^{i=48}(H_i^A + H_i^W)} \quad \text{Eq. (19)}$$

and

$$P_i^W = \frac{H_i^W}{\sum_{i=1}^{i=48}(H_i^A + H_i^W)} \quad \text{Eq. (20)}$$

are the fractions of time when the CPD periods occur during the *i*th interval in autumn and winter, respectively. As the timing of the CPD events vary per year the study calculates H_i^A and H_i^W by taking an average over the years of 2012 to 2016 from data provided by Aurora Energy.

The final CPD annual charges are calculated by multiplying the average CPD period demand $\overline{D}_{CPD}$ by the networks CPD rate in \$/kW/year. CPD prices are provided for an average kW during CPD per day. Four different price scenarios, consisting of relatively low prices are chosen to prevent overestimation. Subsequently, daily charges are scaled to the annual figure. Further details of these calculations can be found in Appendix 2 and Appendix 3. All calculations were separately programmed in R Studio.[3]

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[3] The code is available on request. Email: carsten.dortans@web.de

The probability of CPD events is crucial for calculating the average kW at CPD events. In the following the methodology in the New Zealand context is elucidated. Note that the Aurora data of CPD in the years 2012 to 2016, shows no CPD events in spring or summer. The analysis therefore assumes that the probability of CPD in spring and summer is zero. The x-axis of Fig. 26 constitutes time of day for autumn and winter. On the y-axis, the probability of CPD events for an average day in each season is depicted for every 30-minute period of the day. In both autumn and winter, the probability of CPD events increases during peak times. The study identifies a higher probability and longer duration of CPD events in the winter morning peak than in the winter evening peak. The morning peak in winter attains a CPD probability of 17%, the morning peak in autumn 6%. The probability of CPD events does not display the duration of the individual event but further calculation extends this analysis below.

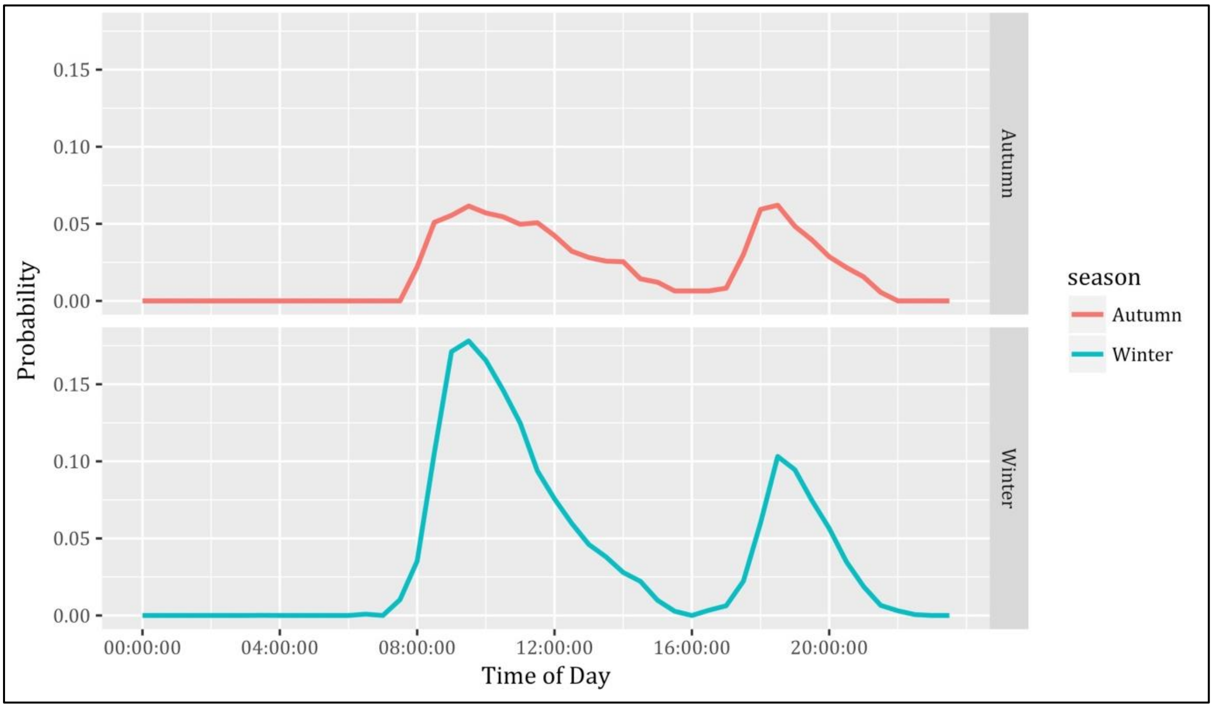

Fig. 26| Probability of CPD events based on Aurora data of CPD in the years 2012 to 2016 of every 30-minute period of the day

Fig. 27 shows the duration of CPD events on a half hourly basis for autumn and winter. The average sum of CPD minutes per half hour and season over the analysed five years of CPD data was multiplied by the individual half hour probability of CPD events. This enables a visualisation of total average CPD hours per half hour and season over the five analysed years. The average duration of CPD events in autumn takes on a value of fourteen hours. The average duration in winter is approximately six times longer, accounting for eighty-two hours in total per year. The average maximum duration of CPD events reaches eight hours during the half hour period from 09:00 to 09:30. Fig. 26 and Fig. 27 build the connection between peaks and occurrence of CPD events, and underline the potential DR has to decrease stress on the utility grid.

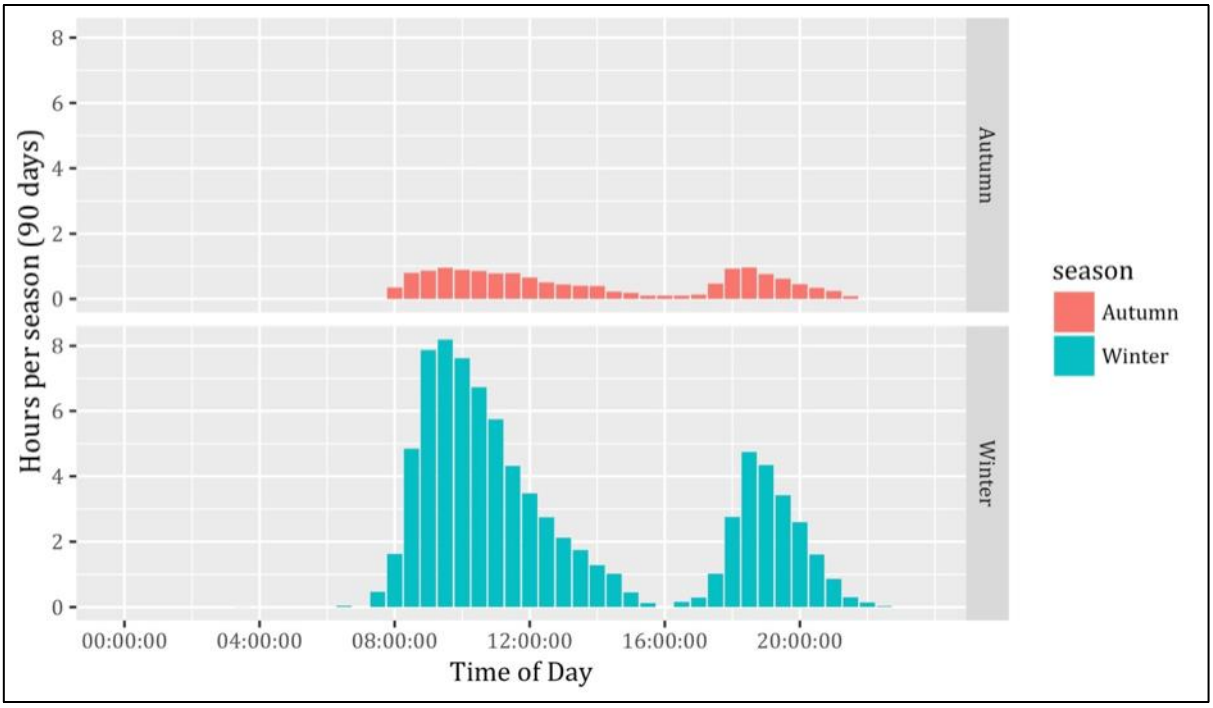

Fig. 27| Total duration of CPD events for autumn and winter

In order to avoid overestimating economic value, the lowest CPD price of $112.38 per kW per year (Comm. Dev. Mgr., 2018, p. 40) and the average probability of occurring CPD events over the four years for every half hour is used in the calculation of the economic value of residential DR. Furthermore, the study assumes that spot market prices and CPD charges, as estimated in the previous sections, can be applied on the forecast for EE. One year of average spot market prices and CPD charges was calculated and utilised for all subsequent years analysed in the EE analysis.

4.6 Combined power potential and economic value of DR and EE

The previous sections separated the power potential and economic value of DR and EE. This is because DR and EE pursue two different approaches to affecting demand at peak times. This section presents the methodology aiming to combine power potential and economic value of DR and EE to provide a more holistic notion on the combined technical potential. Three components constitute the methodology:

1) Combined power potential:
    a. Daily maximum power potential of aggregated demand profiles is linked to the DR analysis of hot water heaters, heat pumps, and refrigeration (see section 5.1);

       This is added to the:

    b. Daily maximum power potential of energy efficient lighting. This is the demand in the 2015 baseline, as presented in section 5.2. Please note that for the demand estimation the equivalent time of day was considered (e.g. the DR demand value at 10:00 is added to the equivalent 10:00 point of EE).

2) Combined energy potential:
    a. Daily energy reduction of aggregated demand profiles is linked to the DR analysis of hot water heaters, heat pumps, and refrigeration (this sums up the daily energy consumption in the morning and evening peak, to display the energy able to be reduced on a daily basis);

       This is added to the:

    b. Daily energy reduction of energy efficient lighting. This estimation substitutes the daily energy consumption during the morning and evening peak in 2029 from the consumption in 2015 to estimate daily energy reduction.

3) Combined economic value:
    a. Annual national savings through DR linked the DR analysis of hot water heaters, heat pumps, and refrigeration as presented in section 5.3 (incorporates spot market prices and CPD charges);

       This is added to the:

    b. Annual national savings through energy efficient lighting. These are savings which result from the savings of the 2029 projection compared with the 2015 baseline, as presented in section 5.4 (incorporating spot market prices and CPD charges).

The results of the DR and EE combination are presented in section 5.5.

5. Results

This chapter presents the main outputs of the calculations for each scenario and appliance group. The chapter is divided into five sections. The first and second section present the results associated with the power potential of DR and EE. Section three and four exhibit the economic value of the estimated power potential. Section five combines the previously separated estimations of DR and EE in order to estimate the overall technical potential of residential DSM.

5.1 Power potential of DR scenarios

The following sections present the demand reduction potential of DR scenarios 1 to 3 for each appliance and group of appliances. Section 5.1.4 furthermore incorporates Scenario 4 in the analysis to provide a more holistic notion on power estimates. Where appropriate, outputs are clarified with associated visualisations to facilitate understanding. The appendices contain additional graphics and tables that potentially enhance the understanding of the analysis.

5.1.1 Heat pumps

Fig. 28 depicts the result of the estimated total New Zealand heat pump electricity demand profile for an average day for each season. The different times of peaks are colour-coded. Power is scaled to MW.

As shown in Fig. 28, most heat pump electricity demand occurs in winter, less demand is seen in spring and autumn, and relatively little in summer. The estimated morning peak in winter is up to 320 MW, while the evening peak in winter is slightly smaller with a maximum of 280 MW. However, the evening peak persists for a longer time than the morning peak. Off-peaks range from less than 40 MW in summer, to 180 MW in winter. Graphic 2 (p. 148) of Appendix 4 depicts the seasonal average energy consumption profile for heat pumps and changes the perspective from a per day demand calculation to a seasonal one scaled in GWh.

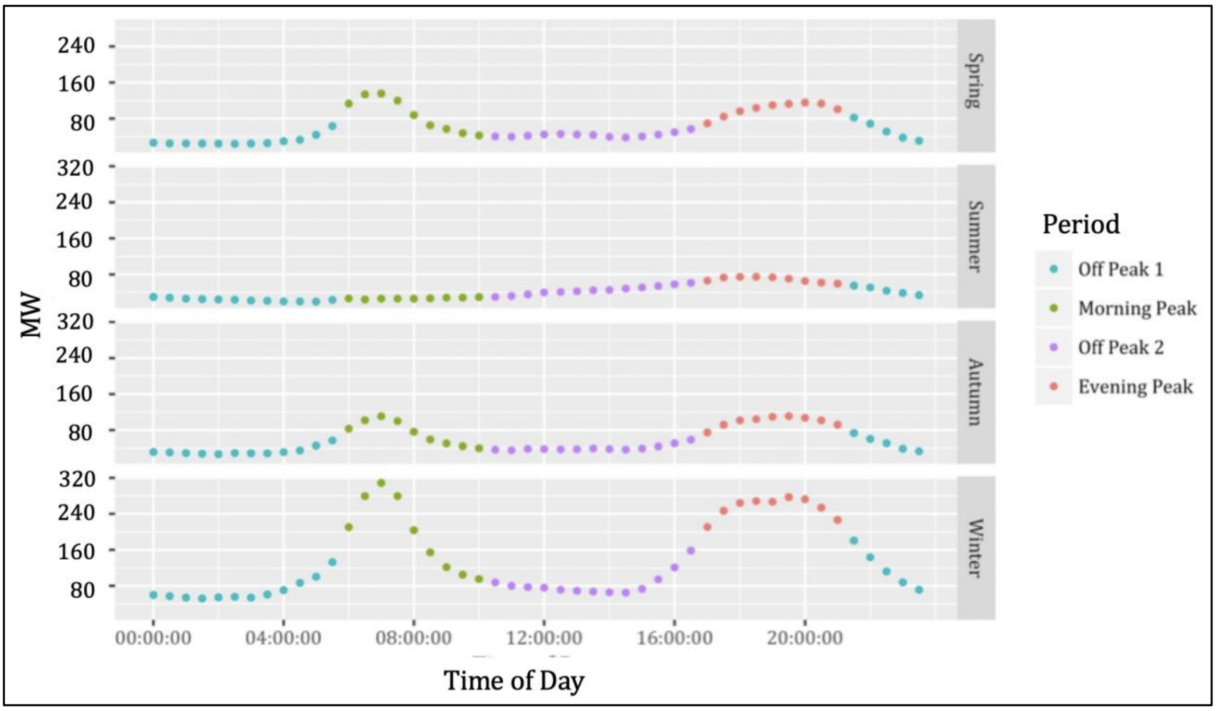

Fig. 28| Estimated daily electricity demand profile for heat pumps

DR Scenario 1 calculates the amount of energy utilised at peaks and sets electricity demand during times of peak demand to zero. Graphic 3 (p. 149) and Graphic 4 (p. 149) of Appendix 4 clarify this process. The morning peak in winter accounts for an energy consumption of 880 MWh, the evening peak for 1,143 MWh per day. Energy consumption on a summer day is 120 MWh in the morning peak and 308 MWh in the evening peak. The proportion of consumption and total generation in winter is 4% in both morning and evening peak (i.e. 4% of energy consumption at times of peak demand is associated with heat pumps) Graphic 3 (p. 149), Graphic 4 (p. 149), Energy output 1 (p.120) and Energy output 2 (p.120) visualise Scenario 1 for heat pump on a per day and seasonal level.

In Scenario 2, the electricity demand during times of peak demand is taken to be half of the demand originally utilised. Energy consumption during periods of peak demand decreases to 440 MWh per day in the winter morning peak and 571 MWh in the evening peak. Energy consumption in the summer morning peak is 60 MWh and in the evening peak 154 MWh per day. Graphic 5 (p. 150), Graphic 6 (p. 150), Energy output 3 (p.120), and Energy output 4 (p. 121) provide more detail on this result (Appendix 2 and 4).

Load shifting in Scenario 3 shifts demand during the period of peak demand to off-peak periods. The evening peak is shifted to off-peak period two and the morning peak is shifted to off-peak period one. Fig. 29 depicts the original and shifted daily electricity demand for heat pumps under this scenario. Graphic 7 (p. 151) and Graphic 8 (p. 151) demonstrate load shifting on a daily and seasonal basis (see Appendix 4).

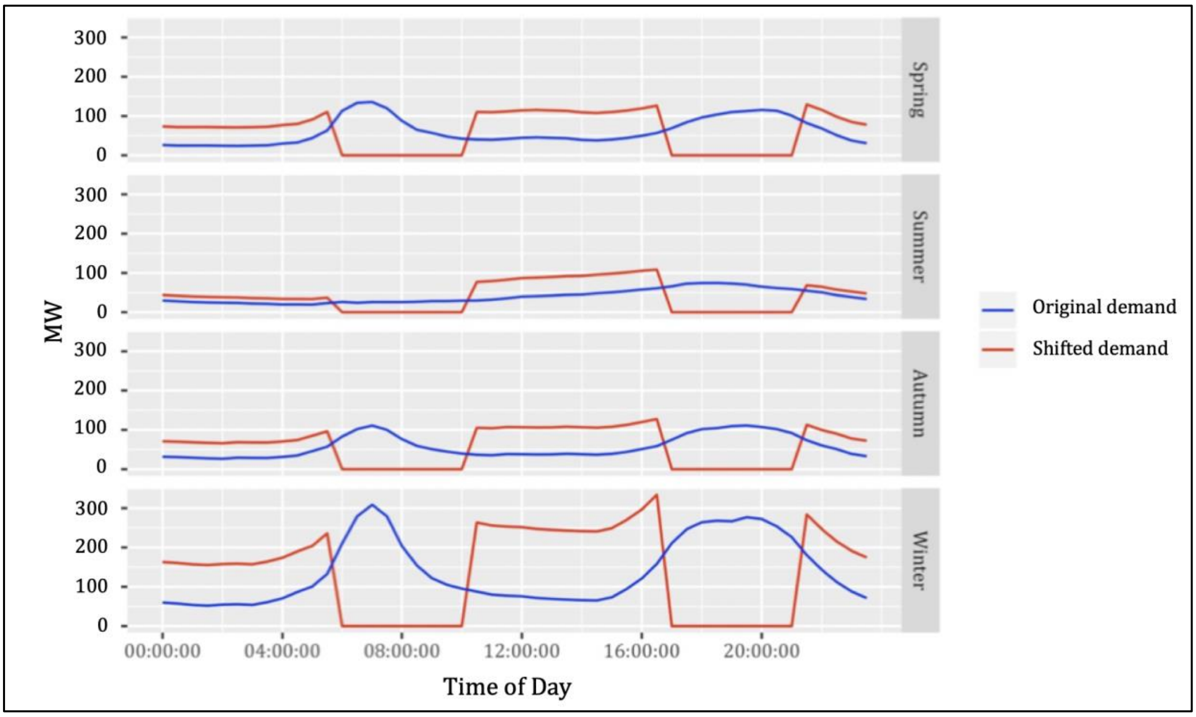

Fig. 29| Estimated daily load shifting profile for heat pumps (Scenario 3)

5.1.2 Hot water heaters

Hot water heaters are already partially utilised for ripple control in New Zealand, although the extent of their use today has not been established. Assuming a 100% availability of hot water units for DR would potentially overestimate the technical potential of residential DSM (see section 3.3.1.2). This thesis incorporates results for a range of available hot water units such as 100%, 80%, 60%, and 40%, so that further research on actual hot water unit availability can incorporate these estimates. For simplicity, the range of available hot water units is only applied to the aggregation of appliances (hot water heaters, heat pumps, and refrigerators) and elucidated in section 5.1.4. The utilised GridSpy dataset incorporates household demand data that is linked to RC receivers. However, during demand monitoring no RC DR was conducted.

Fig. 30 portrays the estimate of the total average demand profile for hot water heaters in New Zealand assuming 100% hot water unit availability. This shows a much higher demand than that for heat pumps. Similar to heat pumps, however, demand for the hot water heaters is at its highest in winter. The morning peak in winter has a peak demand of 1,040 MW. Electricity consumption during this peak period is more than three times that of heat pumps. The evening peak in winter illustrates a lower demand of up to 700 MW. Off peaks range from 80 to 600 MW. The differences in demand across the four seasons are not as dramatic as those of the heat pump.

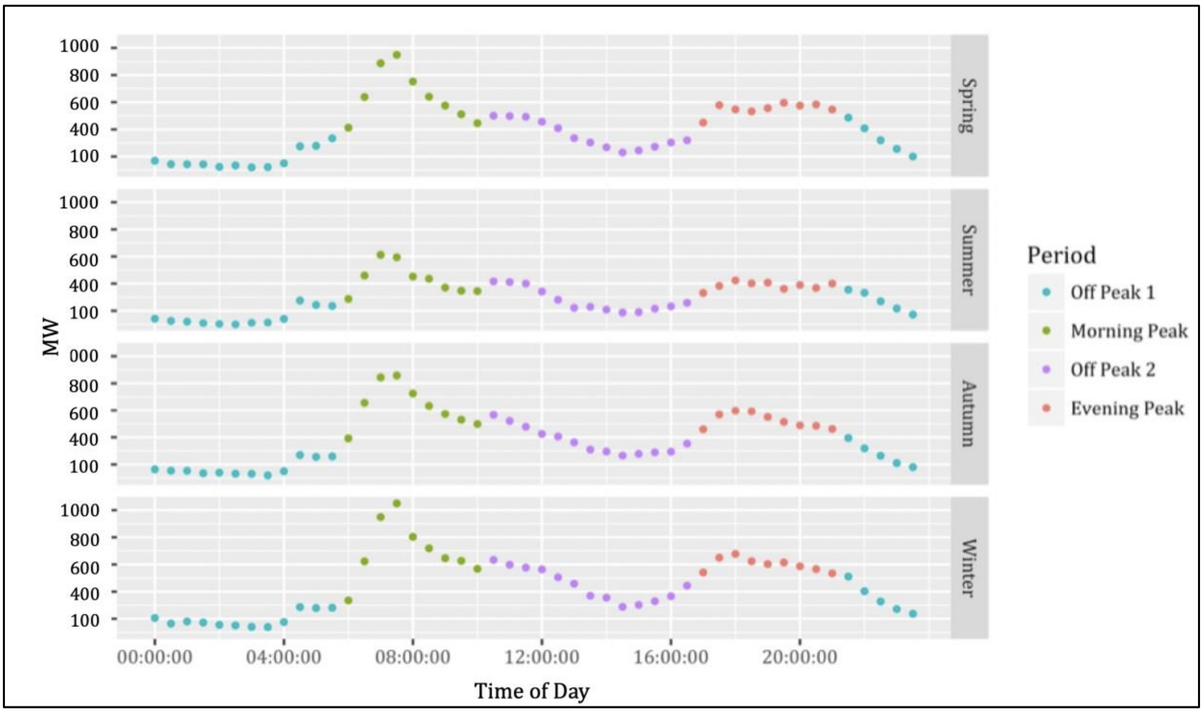

Fig. 30| Estimated daily electricity demand profile for hot water heaters assuming 100% hot water unit availability

Load curtailment under Scenario 1 results in an energy reduction of 3,296 MWh per day in the winter morning peak, and 1,881 MWh per day in the summer morning peak. This represents 13% of the total electricity consumption of New Zealand during the morning peak in winter, and 9% in the summer morning peak. This is three times that of heat pumps. Graphic 11 (p. 153), Graphic 12 (p. 153), Energy output 5 (p. 121), and Energy output 6 (p. 122) clarify these findings (Appendix 2 and 4).

Halving the energy consumption during times of peaks under Scenario **2** decreases consumption to 1,648 MWh in the winter morning peak per day and to 940 MWh in the summer morning peak per day. Graphic 13 (p. 154), Graphic 14 (p. 154), Energy output 7 (p. 122), and Energy output 8 (p. 123) further detail these findings (Appendix 2 and 4).

Fig. 31 highlights shifted and original electricity demand of hot water heaters in New Zealand per day under Scenario 3. Compared to Scenario 1 and 2 this scenario leads to an increase during off-peaks. Graphic 15 (p. 155) and Graphic 16 (p. 155) portray further visualisations pertaining to DR Scenario 3 (Appendix 4).

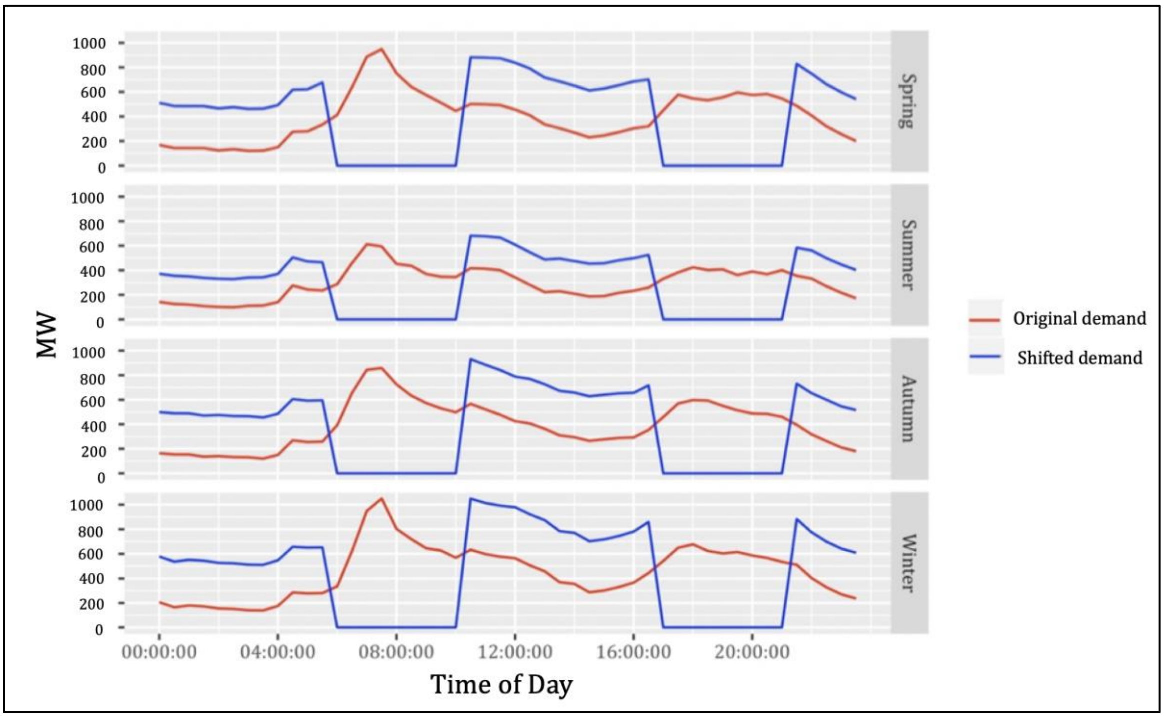

Fig. 31| Estimated daily load shifting profile for hot water heaters (Scenario 3) assuming 100% hot water unit availability

5.1.3 Refrigeration

Refrigerators are the third appliance considered to estimate the technical potential of DR in New Zealand. The electricity demand of refrigerators in this analysis incorporates a flat profile. The study assumes demand does not change during the day or in between seasons but stays at 240 MW throughout the year. The demand by refrigerators is between that of heat pumps and that of hot water heaters. Graphic 17 (p. 156) and Graphic 18 (p. 156) depict the daily and seasonal demand of refrigerators.

Fully curtailed peak demand under Scenario 1 has a DR power potential of 2,160 MW and these values can be associated with all times and all seasons of peak demand, since the demand profile in the model stays the same in each season. This accounts for 4% of NZ's total electricity consumption during times of winter peaks per day, and 5% in summer. In contrast to the previous appliances, the proportion increases in summer due to the reduction in total energy consumed in that season. Graphic 19 (p. 157), Graphic 20 (p. 157), Energy output 9 (p. 123), and Energy output 10 (p. 124) clarify this result (Appendix 2 and 4).

540 MWh for each peak time interval per day can be incorporated in the DR potential for halving peak demand under Scenario 2. The proportion of appliance demand and overall demand in New Zealand in winter decreases to 2% for each peak time interval per day, and to 3% in summer. Graphic 21 p.(158), Graphic 22 (p. 158), Energy output 11 (p. 124), and Energy Output 12 (p. 125) include further visualisation of this scenario (Appendix 2 and 4).

Fig. 32 depicts load shifting of peaks per day. Demand in off-peak times increases from 240 MW to 340 MW and 400 MW, respectively under Scenario 3. The different duration of off-peak 1 and off-peak 2 causes a higher electricity demand in off-peak two. Graphic 23 (p. 159) and Graphic 24 (p. 159) of Appendix 4 illuminate load shifting of peak demand linked to refrigeration as an addition to Fig. 32.

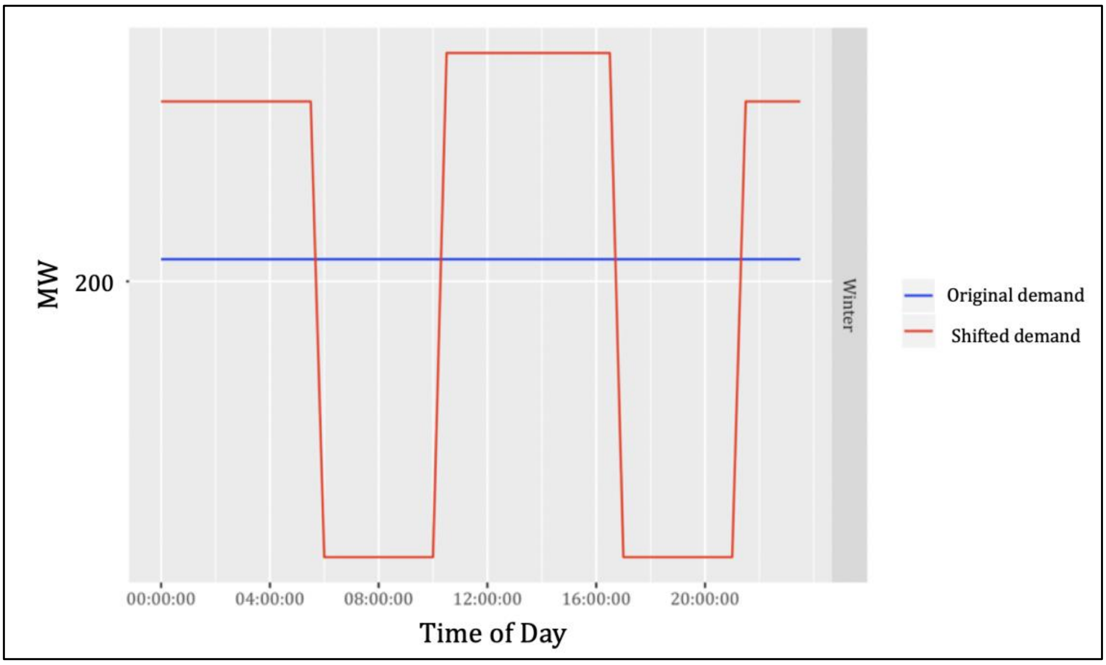

Fig. 32| Estimated total load shifting profile for refrigeration (Scenario 3)

5.1.4 Heat pumps, hot water heaters and refrigerators

In this section the DR potential of the combination of all three household appliances is explored.

Fig. 33 portrays the total demand profile for an average day for each season due to the three household appliances for a 100% hot water unit availability. This shows an electricity demand in the winter morning peak of up to 1,600 MW. This represents 20% of national demand during this period. In the evening peak in winter, demand reaches 1,200 MW representing 18% of average national demand during this period. Off-peak demand for all three appliances combined varies between 400 MW in summer, and 1,000 MW in the winter. Graphic 33 (p. 164) and Graphic 34 (p. 164) of Appendix 4 depict the demand profile of the three household appliances for an average day in each season and on a seasonal basis.

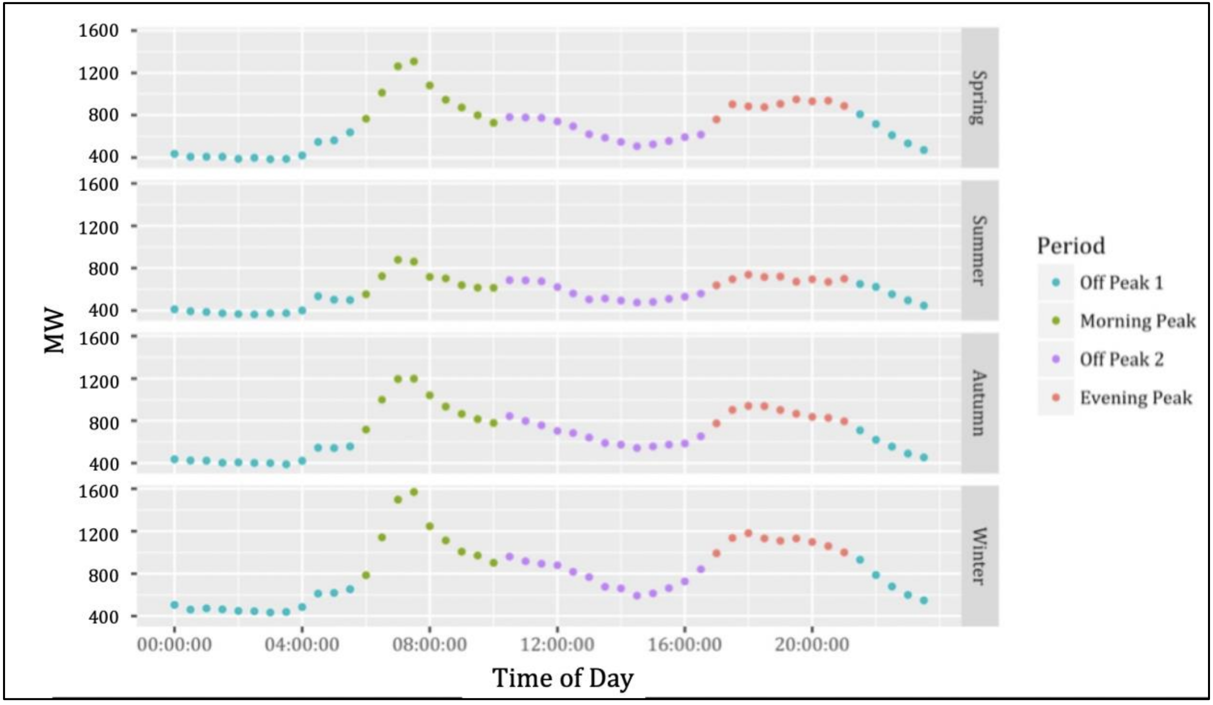

Fig. 33| Estimated electricity demand profile for HP, HW and REF together, assuming 100% hot water unit availability

As mentioned in section 5.1.2 it is not clear how much capacity of residential hot water units is already utilised for DR. The analysis of a range of available hot water units estimates that under 100% hot water unit availability, hot water heaters account for up to 12% of the total load during the winter evening peak, as depicted in Table 6. This proportion decreases to 8% in the summer evening peak. As electricity demand remains stable for refrigeration, the potential national load reduction varies slightly between 4% in the winter and 5% in the summer. This variation is caused by different total demand profiles as shown in Fig. 32. For heat pumps, the potential load reduction varies between 1% in summer and 4% in winter.

Table 6: Potential load reduction (as a percentage of total load) by appliance for 100% hot water unit availability

Season	*Period*	*Hot Water (100%)*	*Refrigeration*	*Heat Pump*
Summer	Morning Peak	9%	5%	1%
Summer	Evening Peak	8%	5%	1%
Winter	Morning Peak	10%	4%	4%
Winter	Evening Peak	12%	4%	4%

Table 7 extends these findings by incorporating a range of hot water unit availabilities into the analysis. Decreasing unit availabilities noticeably reduce the overall potential of DR. The maximum of 20% load reduction in the winter evening peak (considering hot water, heat pump, and refrigeration) decreases to 13% load reduction under 40% hot water unit availability. The former 15% load reduction in the summer morning peak under 100% hot water unit availability is reduced to 10% load reduction under 40% of available units. These results corroborate the significance of hot water heaters to provide DR and enable a more holistic notion of DR potentials based on the appliances analysed.

Table 7: Potential aggregated (HW, HP, REF) load reduction (as a percentage of total load) for a range of hot water unit availabilities

Season	*Period*	*100% HW units available*	*80% HW units available*	*60% HW units available*	*40% HW units available*
Summer	Morning Peak	15%	13%	11%	10%
Summer	Evening Peak	14%	13%	11%	10%
Winter	Morning Peak	18%	17%	14%	12%
Winter	Evening Peak	20%	18%	16%	13%

The following results depict estimates for DR for all three appliances assuming 100% hot water unit availability.

Load curtailment (Scenario 1) of all three household appliances at peaks reduces energy consumption by 5,260 MWh per day in the winter morning peak, and 5,040 MWh in the evening peak time interval. In the morning this comprises 3,300 MWh for hot water heaters, 1,080 MWh for refrigerators and 880 MWh for heat pumps. In the evening it comprises 2,810 MWh for hot water heaters, 1,080 MWh for refrigerators, and 1,140 MWh for heat pumps. Furthermore, the reduction of energy consumption under Scenario 1 equates to 3.60 kWh in the winter morning peak, and 3.40 kWh in the evening peak per household. This is 20% of the total electricity generation in New Zealand during this interval.

In the summer, less utilisation of heat pumps decreases this to 15% of total demand in the morning peak period and 14% in the evening. In combination, the appliances modelled could provide a maximum aggregated energy reduction of 3,081 MWh in the summer morning peak, and 3,131 MWh in the summer evening peak. Graphic 35 (p. 165), Graphic 36 (p. 165), Energy output 17 (p. 127), and Energy output 18 (p. 128) show the per day and seasonal energy consumption profile (Appendix 2 and 4).

Halving electricity demand at peaks (Scenario 2) creates a DR energy potential of 2,628 MWh per day during the winter morning peak, and 2,518 MWh in the evening peak. In summer, 1,540 MWh per day can be reduced during the morning peak and 1,565 MWh per day in the evening peak. This accounts for 10% of electricity generation in morning peaks in winter and 8% in the summer. Graphic 37 (p. 166), Graphic 38 (p. 166), Energy output 19 (p. 128), and Energy output 20 (p. 129) highlight this development (Appendix 2 and 4).

Fig. 34 depicts the demand profiles of each appliance, all three appliances and also DR Scenario 3. Graphic 39 (p. 167) and Graphic 40 (p. 167) visualise load shifting for an average day in each season and for a seasonal demand profile (Appendix 2 and 4).

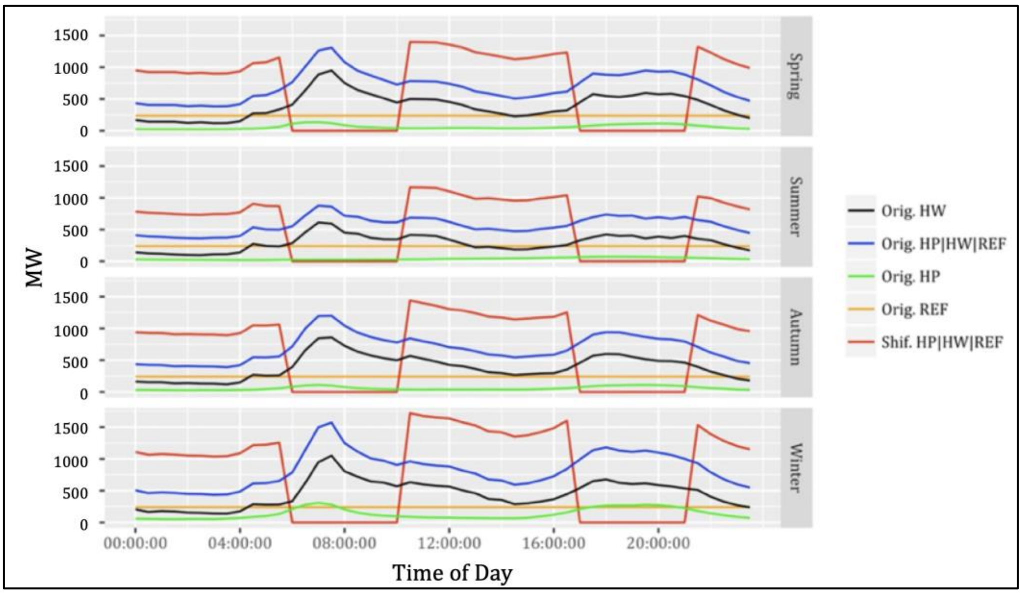

Fig. 34| Estimated total load shifting profile for HP, HW, and REF (Scenario 3) assuming 100% hot water unit availability

These results estimate a total potential daily demand reduction for the aggregation of hot water heaters, heat pumps, and refrigeration of 1.2-1.6 GW in the winter morning and evening peak under 100% availability of hot water units. This equates to a daily energy shifting potential (equivalent to Scenario 1) of 5.0-5.2 GWh per day in these periods of times in winter (3.3 kWh per household). Fig. 35 and Fig. 36 clarify these findings.

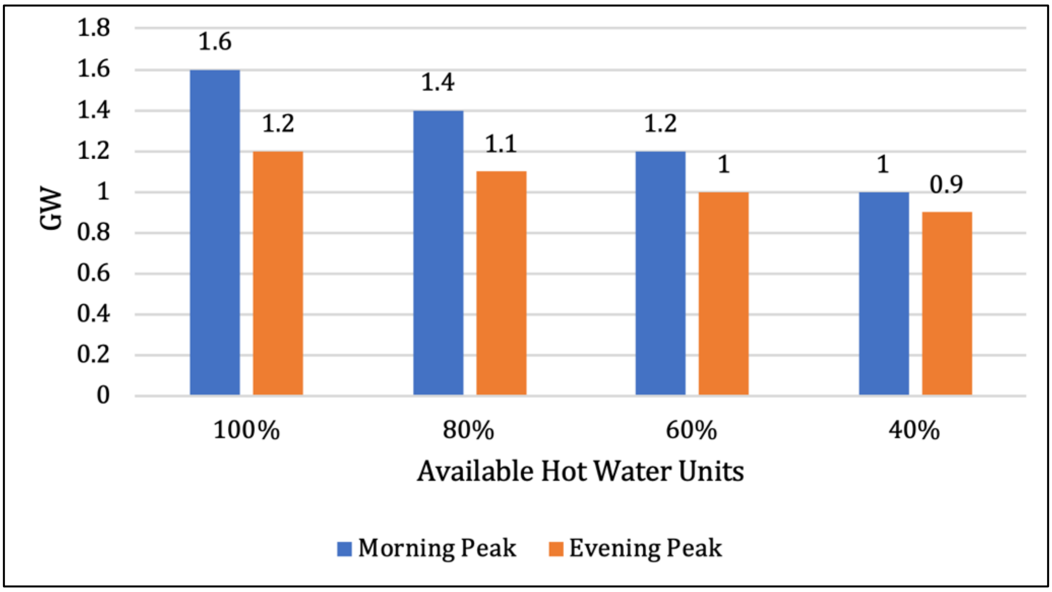

Fig. 35| Potential maximum daily load reduction for HW, HP, and REF for different HW unit % availabilities in winter morning and evening peak

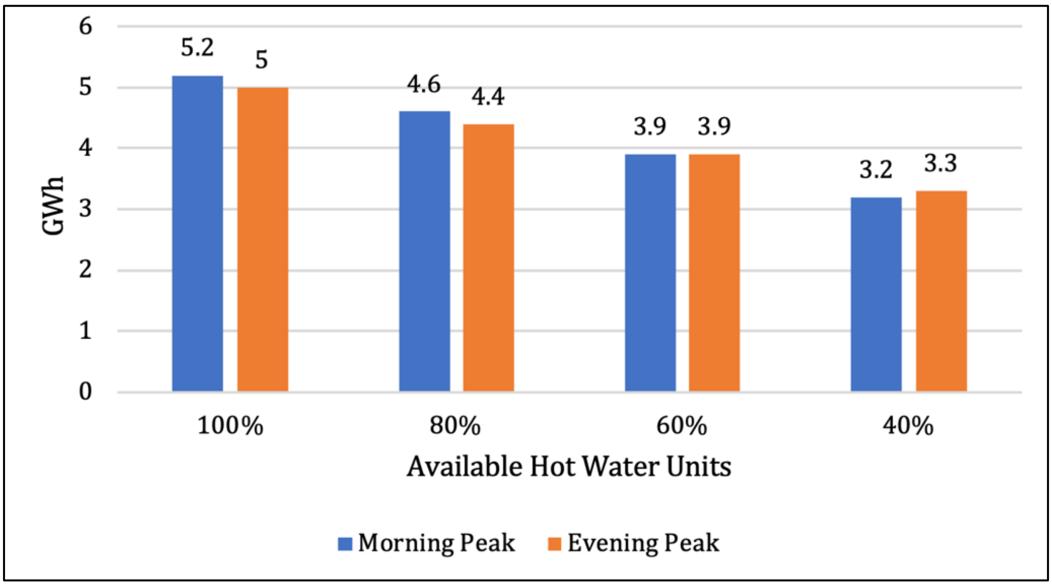

Fig. 36| Potential daily energy shifting for HW, HP, and REF for different HW unit % availabilities in winter

Reducing available hot water units utilised for DR, results in a decrease in the potentially daily load reduction and load shifting. Under 40% availability of hot water units, potential load reduction is limited to 0.9-1.0 GW in winter. Concurrently, energy able to shift out of the morning and evening peak time period is reduced to 3.2-3.3 GWh per day.

Fig. 37 shows the impact of the DR scenarios on the total daily electricity demand profile in New Zealand during summer and winter, assuming a 100% availability of hot water units. The blue line depicts original electricity generation. DR scenarios are portrayed in the colours green (Scenario 1), yellow (Scenario 2), and red (Scenario 3). This figure presents a visualisation of the DR potential of these residential appliances relative to total demand. As stated in section 1, conducting DR simultaneously has the potential of causing a rebound effect on the electricity network. This becomes evident in Fig. 37 when demand of Scenario 3 exceeds peak demand. Furthermore, it is questionable whether load shifting of residential refrigeration and space heating is technically feasible for 4.5 hours. This issue is identified as future work and not examined in this work.

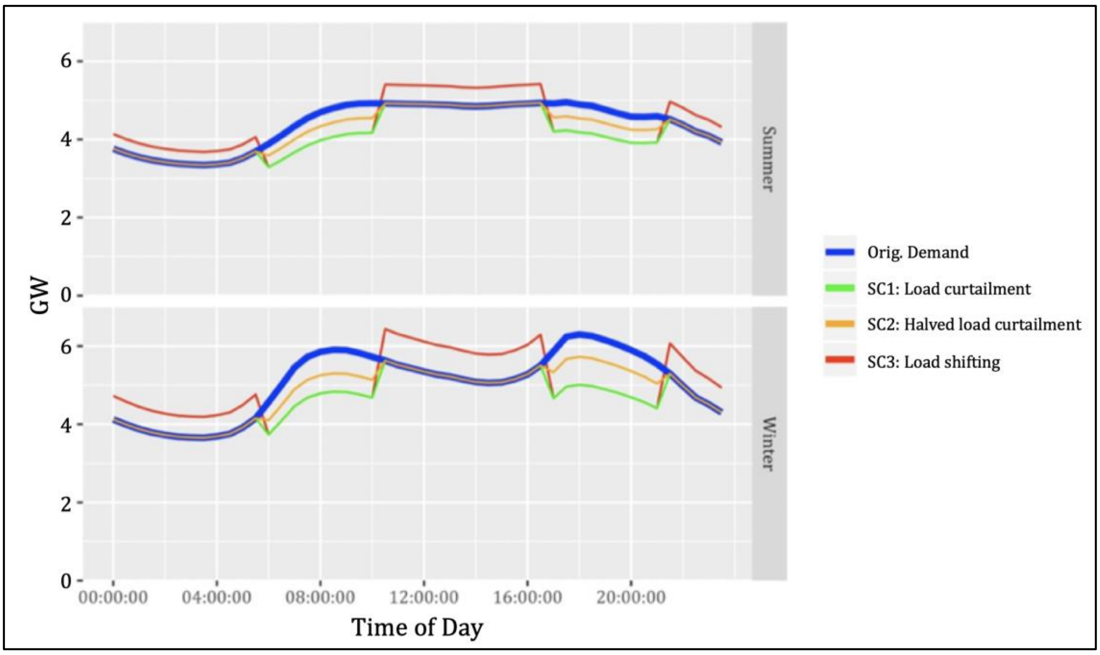

Fig. 37| Estimated daily effects of DR scenarios 1-3 on total electricity demand profile assuming 100% hot water unit availability

A fourth scenario "responding to all CPD events" estimates the power use that could be reduced when households reduce demand at congestion periods. This scenario has the benefit that demand would only have to be reduced at approximately 100 hours per year instead of every day for the morning and evening peak, as required by scenarios 1 to 3, to generate these results.

Analysis of the "responding to all CPD events" scenario showed that the average national power demand that could be reduced during congestion periods was 570 MW for hot water heaters, 100 MW for heat pumps, and 200 MW for refrigerators, providing a total of approximately 900 MW (or 0.85 kW per household). This estimate assumes a 100% availability of hot water units. A range of hot water availabilities is depicted in Table 8 and connected to Scenario 4. Under 40% hot water unit availability, average CPD able to be reduced decreases to 0.58 kW per household, while hot water power is reduced to 250 MW, resulting in total power utilised for DR being approximately 600 MW. Hot water units only affect hot water heaters; thus, heat pump and refrigeration power remain at the same values throughout this analysis.

Table 8: Potential load reduction for "reduce congestion" scenario by appliance for different HW unit % availabilities

Available HW units	*Average aggregated CPD per household*	*Hot Water Power national*	*Heat Pump Power national*	*Refrigeration Power national*	*Total Power national*
100%	0.85 kW	570 MW	100 MW	200 MW	≈ 900 MW
80%	0.76 kW	480 MW	100 MW	200 MW	≈ 800 MW
60%	0.67 kW	370 MW	100 MW	200 MW	≈ 700 MW
40%	0.58 kW	250 MW	100 MW	200 MW	≈ 600 MW

5.1.5 All appliances

Despite the fact that lighting in residential households may not be used for DR (due to the absence of storage ability), electricity demand of lighting for 2015 is included in the aggregation of appliances to estimate the maximum power potential for residential household appliances linked to DR scenarios. A separate analysis for lighting that considers the multi-annual analysis described in section 4.4 is presented in section 5.2.

Fig. 38 depicts the daily electricity demand profile for each appliance analysed (labelled by A-D) as well as the aggregation of appliances (depicted in black) assuming 100% hot water unit availability. The analysis identifies that lighting in residential households increases electricity demand in the winter morning peak from 1,600 MW to 2,000 MW and from 1,200 MW to 1,940 MW in the evening peak. This is an increase of approximately 25% in the winter morning, and 60% in the winter evening peak. Lighting thus represents a significant contribution to the electricity demand of the analysed appliances in residential households, particularly in the winter evening peak, and exceeds electricity consumption of hot water heaters during this time by 5 MWh (see Appendix 2)

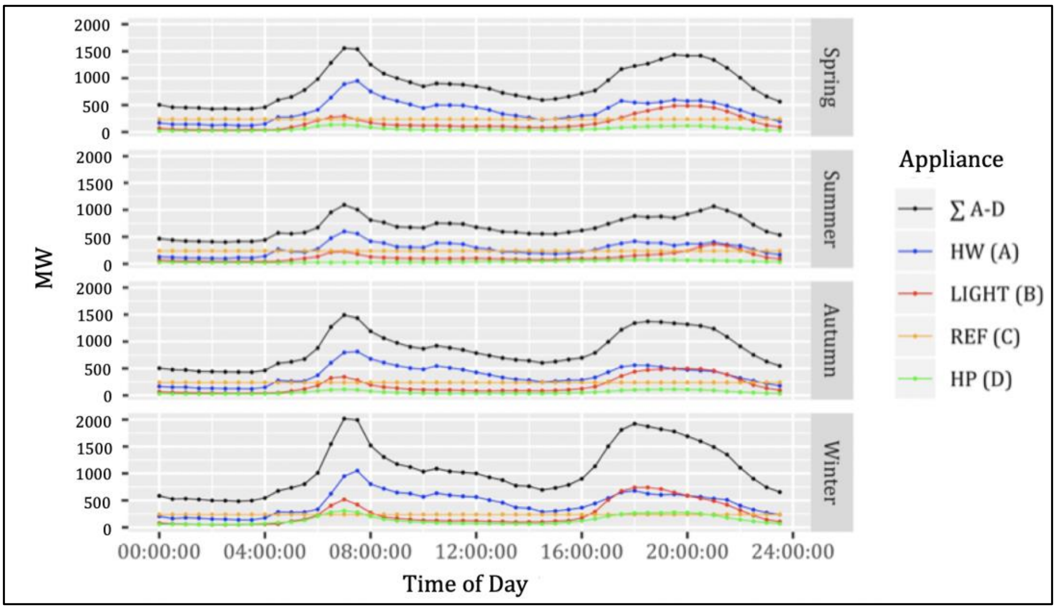

Fig. 38| Estimated daily total electricity demand profile for HP, HW, REF, and LIGHT by season

5.2 Power potential of energy efficient lighting

Section 5.1.5 illustrated the contribution of lighting to the overall aggregated electricity demand profile of hot water heaters, heat pumps, and refrigerators. As lighting does not encompass the storage ability of warm water or warm/cold air, interruption of demand as executed by DR may not be of use. However, EE reduces electricity demand permanently by incorporating more efficient technologies. This leads to a decreasing demand at all times and thus enables power potential and economic value for EE at residential lighting appliances in households. This section utilises the RBS in conjunction with GREENGrid monitored demand data of lighting appliances to estimate the power potential of EE from the year 2015 to 2029. The economic value of energy efficient lighting is presented in section 5.4.

Fig. 39 depicts the lighting stock for residential household appliances by technology in million units. In the baseline year 2015, incandescent lights constituted the majority of residential households (25M) followed by compact fluorescent (17M) and electric low voltage halogen lights (7M). The RBS predicts a decrease of incandescent lights of 50% by 2022 and an increase in compact fluorescent lights of 100% by 2025, with a subsequent decrease. Electric low voltage halogen lights are forecast to remain at 4-7M units. A stark increase of light-emitting diodes from 2M in 2015 to 31M in 2030 is forecast to replace the less efficient incandescent and compact fluorescent light units in New Zealand households. These developments are further shown in Table 9.

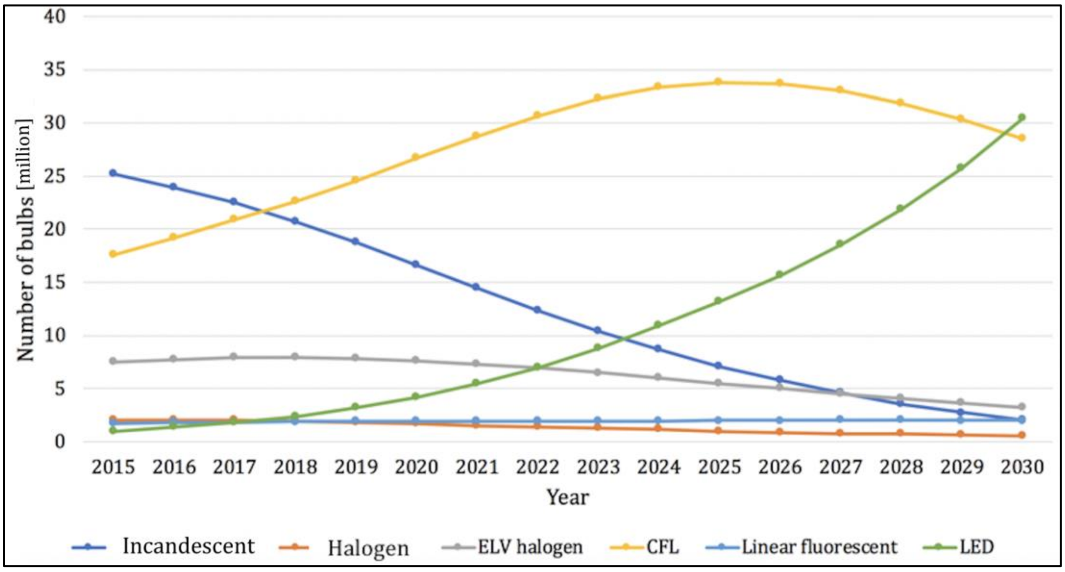

Fig. 39| New Zealand household lighting stock by technology

Source: Based on (EnergyConsult PTY LTD, 2015).

Table 9: Stock proportions for residential lighting in 2015 and 2029

Lighting technology	**Stock proportion in the residential sector in 2015**	**Stock proportion in the residential sector in 2029**
Incandescent	46%	3%
Halogen	4%	1%
Electric low voltage halogen	14%	5%
Compact fluorescent	32%	43%
Linear fluorescent	3%	3%
Light-emitting diode	2%	46%

This increase in EE and subsequent decrease in energy use is corroborated by the prediction of national energy consumption for household lighting units based on the RBS. Fig. 40 depicts this development and illustrates the link between the prevalence of incandescent lights and high energy consumption. The year 2015 was characterised by a high proportion of incandescent lights and the total energy consumption reached approximately 1,600 GWh. As the penetration of low efficient incandescent lights decreases, as depicted in Fig. 39, energy consumption of lighting in households is forecast to decrease by 60% to the year 2030. It is clear then, that the total energy consumption takes on the same profile as the reduction of incandescent lights, which supports the idea of incandescent lights constituting the majority of lighting energy consumption in households.

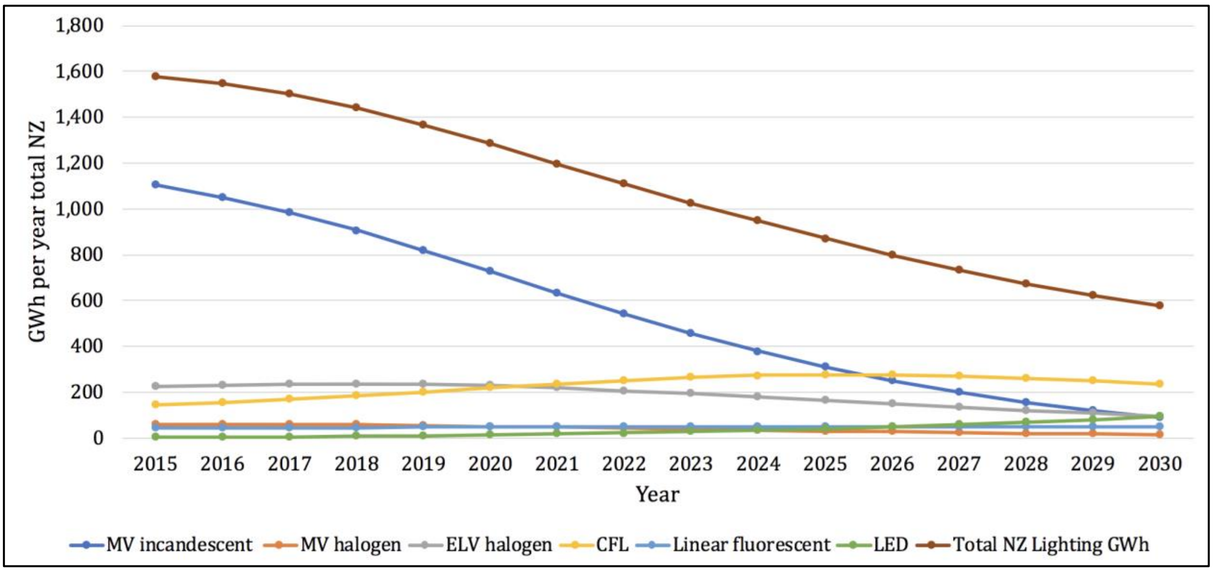

Fig. 40| Development of national lighting household energy consumption by technology

Source: Based on (EnergyConsult PTY LTD, 2015).

Fig. 40 does not analyse time of day variations but solely provides an annual figure. The GREENGrid monitored data, in conjunction with the RBS, enables a more detailed temporal analysis. The calculations elucidated in section 4.2.5 precede this analysis by estimating a scaling factor for each analysed year. These results are applied to the monitored daily average consumption profile and visualised in Fig. 41. Each line represents one year and lighting's associated daily average energy consumption per half hour in each season. In contrast to hot water heaters, most lighting energy consumption is apparent in the evening peak. In summer, this energy consumption is less than in winter and shifts to a later time, as daylight persists longer and does not necessitate as much morning and evening lighting.

Dividing these consumption profiles into the predefined periods portrayed in section 4.1 enables a comparison of lighting electricity demand for the years 2015 and 2029, as depicted in Fig. 42.

In 2015, demand in the winter morning peak reaches 540 MW per half hour while the evening peak moves up to 780 MW. The daily average energy consumption is approximately 1,200 MWh in the morning, and 2,800 MWh during the evening peak. In summer, the morning peak constitutes 260 MW and the evening peak 400 MW in 2015. Energy consumption over the whole peak period in summer takes 640 MWh in the morning and 920 MWh in the summer evening peak.

The increasing penetration of light-emitting diodes and compact fluorescent lights by 2029 significantly decreases electricity demand. In the winter morning peak, demand is reduced by 65% to 200 MW, constituting 490 MWh per day of utilised energy in this period of time. During the evening peak, demand reaches a maximum of 280 MW, which is estimated to be a reduction of 65% compared with the year 2015. Energy consumption over this period of time is 1,100 MWh per day. In summer, the morning peak reaches 100 MW and comprises of a daily average energy consumption of 250 MWh while the summer evening peak is up to 140 MW and 360 MWh per day. In total, daily energy consumption in winter in 2029 is forecast to be reduced by 2,460 MWh compared to 2015. These findings and developments are further visualised for each analysed year in Energy output 21-Energy output 36 (p. 129-137) of Appendix 2 as well as summarised in Table 10.

Table 10: Maximum residential lighting demand in 2015 and 2029

	Year: 2015	**Year: 2029**
Maximum lighting demand in winter	780 MW	280 MW

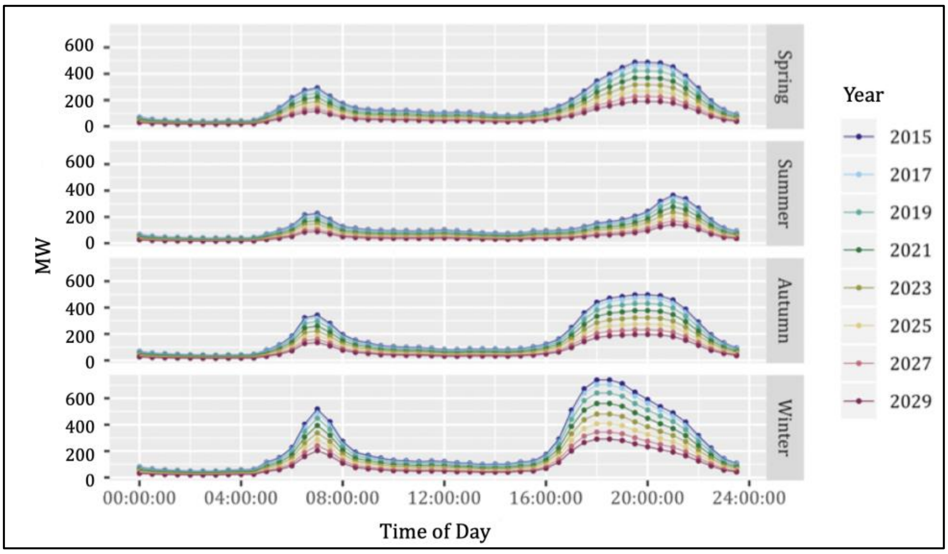

Fig. 41| Daily average total lighting electricity demand profile by year

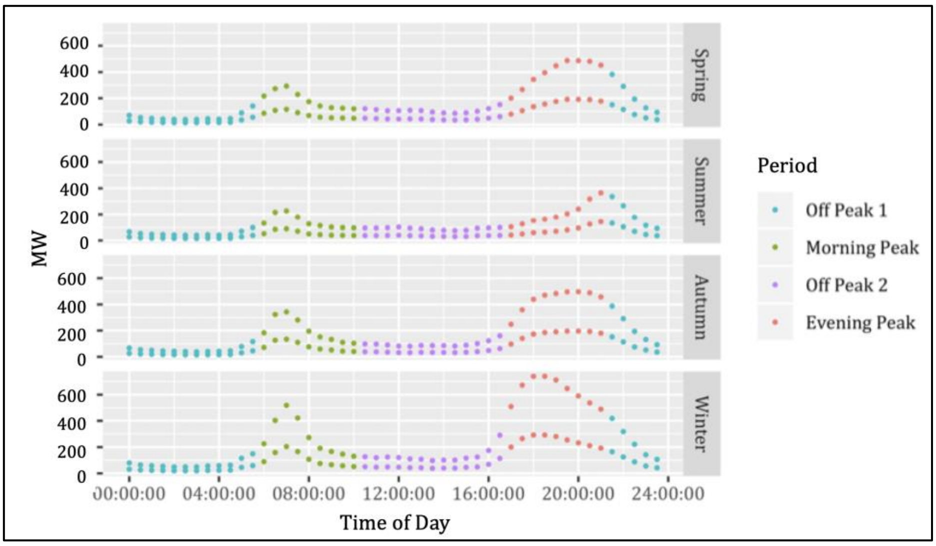

Fig. 42| Daily average total lighting electricity demand profile for 2015 and 2029

EE has the potential of permanently reducing individual household electricity demand, but it also enables a reduction of required electricity generation in New Zealand. This becomes evident when the total electricity generation profile is linked to increasing EE of residential lighting units in households, as depicted in Fig. 43. Increasing EE will particularly affect the period of peak demand in winter and is estimated to reduce total electricity demand in 2029 by up to 9% (equivalent to 500 MW) compared to 2015.

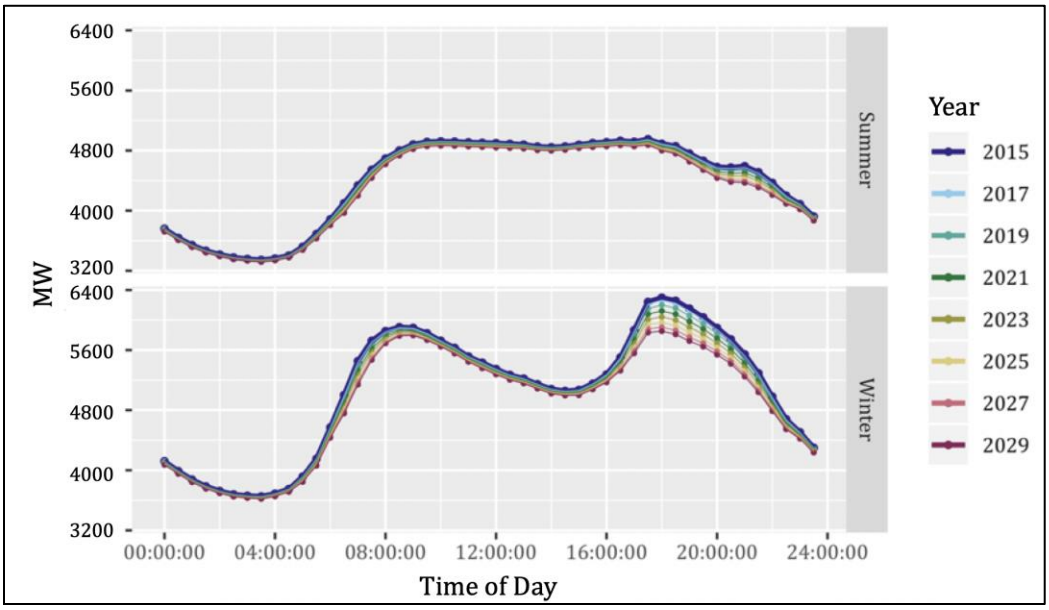

Fig. 43| Impact of increasing lighting EE on required electricity generation for summer and winter

5.3 Economic value of DR scenarios

In this second part of the. results, the focus is on the economic value of DR and EE. In this thesis the economic value of each DR scenario is estimated based on currently available data on spot market prices and CPD charges. First, the study estimates the economic value based on spot market prices.

5.3.1 Spot market prices

In a first step, the study will analyse the cost of the economic value of DR scenarios. In a second step, savings are presented, and the economic value of load shifting is elucidated in detail.

The analysis calculated a baseline value for each appliance aggregation. This baseline value consists of the total cost for supplying electricity to consumers. Based on spot market prices alone, in the baseline scenario, heat pumps have the lowest cost per year at $53M. Hot water heaters, in contrast, cost $248 M per year. Refrigerators are in between and cost $136M per year. Aggregating all appliances together generates costs of $438M. In general, the more energy consumption occurs during times of peak demand, particularly in winter, the higher the cost.

Load curtailment to zero under Scenario 1 saves 41% of the cost described in the baseline scenario of refrigerators, and up to 62% of the cost described in the baseline scenario of heat pumps per year. The aggregation of all three appliances generates savings of 52% per cent, equivalent to $230M per year. Halving load (Scenario 2) at peaks decreases the savings by 50% compared to a full load curtailment. This underlines the impact peaks have on the total cost per year. In the load shifting scenario (Scenario 3), although the total energy consumption stays the same, the timing of demand is adjusted. This scenario achieves 6 to 8% savings compared to the baseline. The aggregation of all three appliances saves 5% of the baseline cost, equivalent to $24M per year. The Economic output 1 (p. 139) depicts the aforementioned cost and savings in more detail (see Appendix 3).

In the following, the results for load shifting (Scenario 3) aggregating heat pumps, hot water heaters, and refrigerators are presented.

Fig. 44 depicts costs for an average day per season in the baseline scenario for each half hour time interval when spot market costs (see section 4.5.1) are applied to the aggregated energy consumption profile of heat pumps, hot water heaters, and refrigerators. The figure displays the fluctuation of average daily spot market prices for each season. The highest costs in winter are identified with up to $120,000 per half-hour in the morning peak, and up to $70,000 in the evening peak. The lowest spot market prices are found in summer, with values up to $28,000 per half-hour in the morning peak, and $25,000 in the summer evening peak.

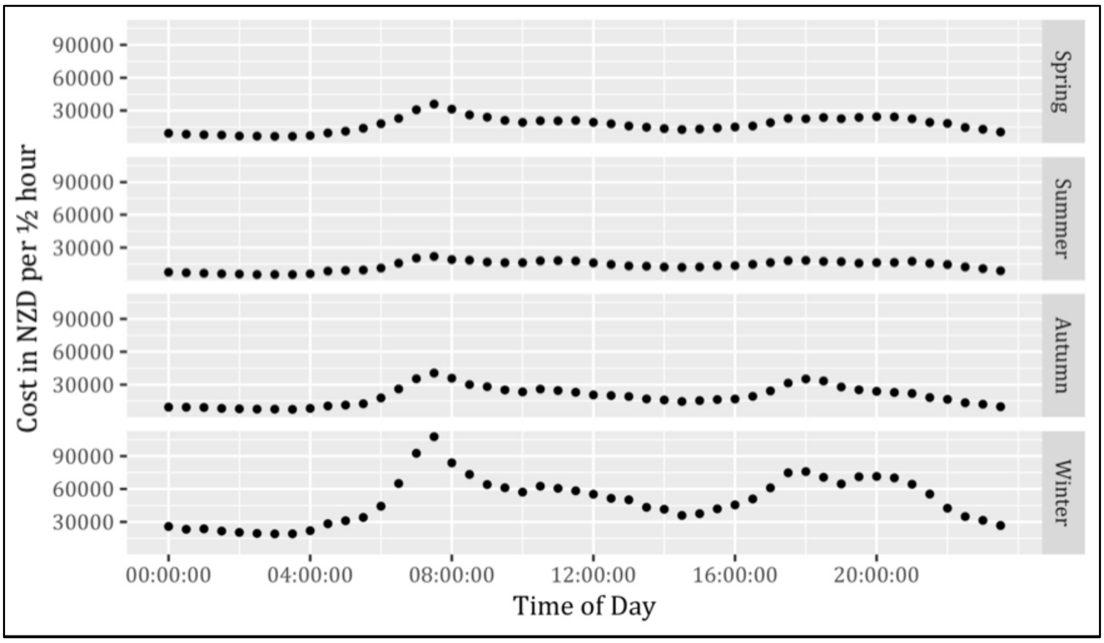

Fig. 44| Estimated total cost of electricity use for heat pumps, hot water heaters, and refrigeration for an average day per season (no DR applied)

5.3.2 Incorporating spot market prices and CPD charges

This section focuses particularly on the aggregation of heat pumps, hot water heaters, and refrigerators. In addition to the scenarios described in section 4.3, a fourth scenario has been added: response to all CPD events. This scenario assumes that participants drop all their demand in response to CPD events on a half hourly basis (i.e. although the CPD event might be only 20 minutes long, demand is curtailed for the full half hour) and need to increase demand after the CPD event to retrieve the same level of service. For simplicity, this study assumes that participants who respond to all CPD events only pay spot market prices equivalent to the baseline cost of spot market prices, although the price in the half-hour of increased electricity demand might be different. Fig. 45 shows the total cost per year in million $ when spot market prices as well as CPD charges are considered.

Incorporating CPD charges increases the total cost per year by 25% to $545M in the baseline scenario. This assumes that no DR scenario is applied. Fig. 46 provides the percentage of the baseline cost due to each appliance.

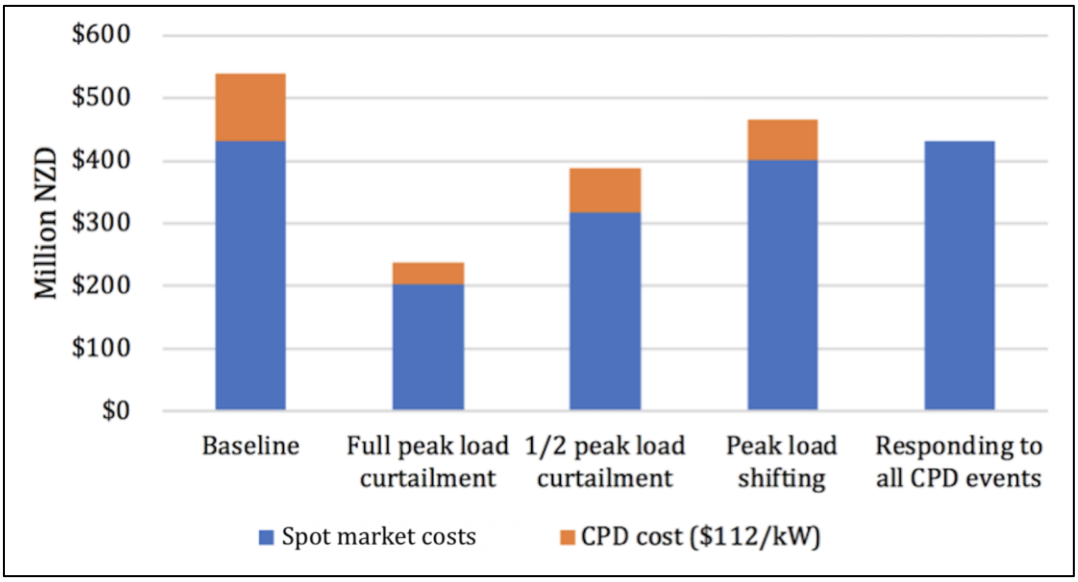

Fig. 45| Cost per year for HP, HW, and REF (scenarios 1-4)

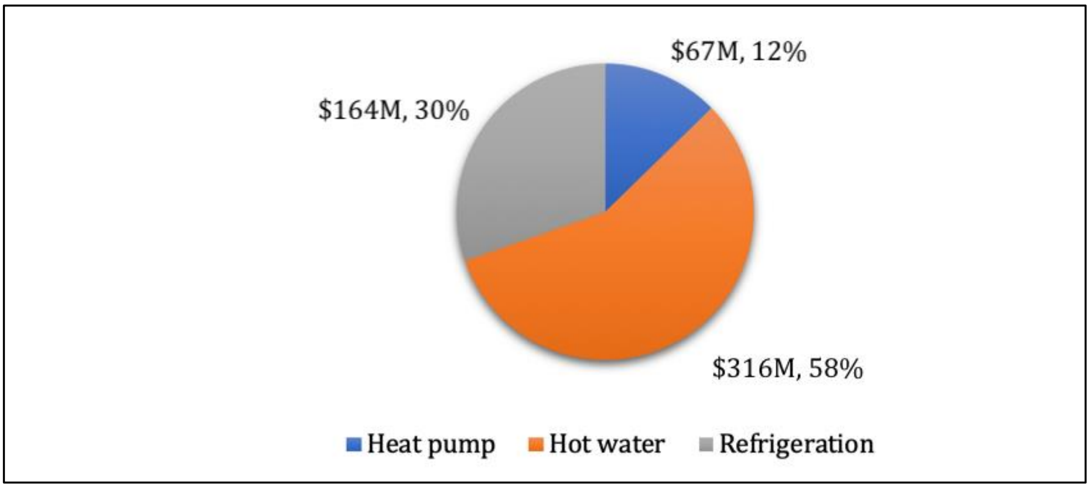

Fig. 46| Baseline costs by appliance per year for HP, HW, and REF in million $

58% of the total annual costs are due to hot water heaters, followed by refrigerators at 30%, and heat pumps with 12%. The annual costs of each scenario are presented in Fig. 45. Savings relative to the baseline decrease across the DR scenarios 1 to 3. The higher the energy consumption, especially during periods of peak demand, the higher the annual costs. Fig. 47 shows the savings relative to the baseline for all scenarios including DR Scenario 4: responding to all CPD events.

Load curtailment under Scenario 1 decreases the aggregated CPD demand of heat pumps, hot water heaters, and refrigerators per household from 0.85 kW to 0.26 kW. Not all CPD events occur during the defined peak periods, therefore some residual costs CPD costs remain in this scenario.

Halving the electricity demand at peak times under Scenario 2 reduces CPD savings compared to the baseline scenario by 50%. CPD demand (in kW) increases from 0.26 kW at full load curtailment to 0.55 kW due to the increased demand at times of peak demand that coincides with CPD events. Halving electricity demand at peaks generates annual savings of $150M.

Load shifting under Scenario 3 is the least beneficial DR scenario in the presented environment, but considers all of the demand incorporated in the originally aggregated electricity demand profile. Spot market price savings are reduced to $30M per year and CPD savings take on a value of $42M. Spot market prices and CPD charges at peak time intervals are zero and shifted to off-peak time intervals one and two. This increase of electricity demand at off-peak times reduces the savings. This scenario generates annual savings relative to the base scenario of $72M per year and a large percentage of this is from avoiding CPD charges.

Responding to all CPD events (Scenario 4) and therefore reducing congestion generates savings of about $108-70M per year, depending on the percentage of available hot water heaters. This result is depicted in Fig. 49.

From an individual household perspective, the peak load shifting scenario equates to a saving of $40 per year and the reduced congestion scenario equates to a saving of $75 per year under a 100% availability of hot water units. It is worth remembering that in this scenario DR only occurs for around 100 hours per year compared to 8 hours a day in the other scenarios. Fig. 48 depicts savings by appliance per year for Scenario 3 and Scenario 4 and clarifies the impact of reducing CPD charges on annual savings. Economic output 2 (p. 140), Economic output 3 (p. 141), Economic output 4 (p. 142), and Economic output 5 (p. 143) of Appendix 3 present further results for the four scenarios for costs and savings as totals and per household basis.

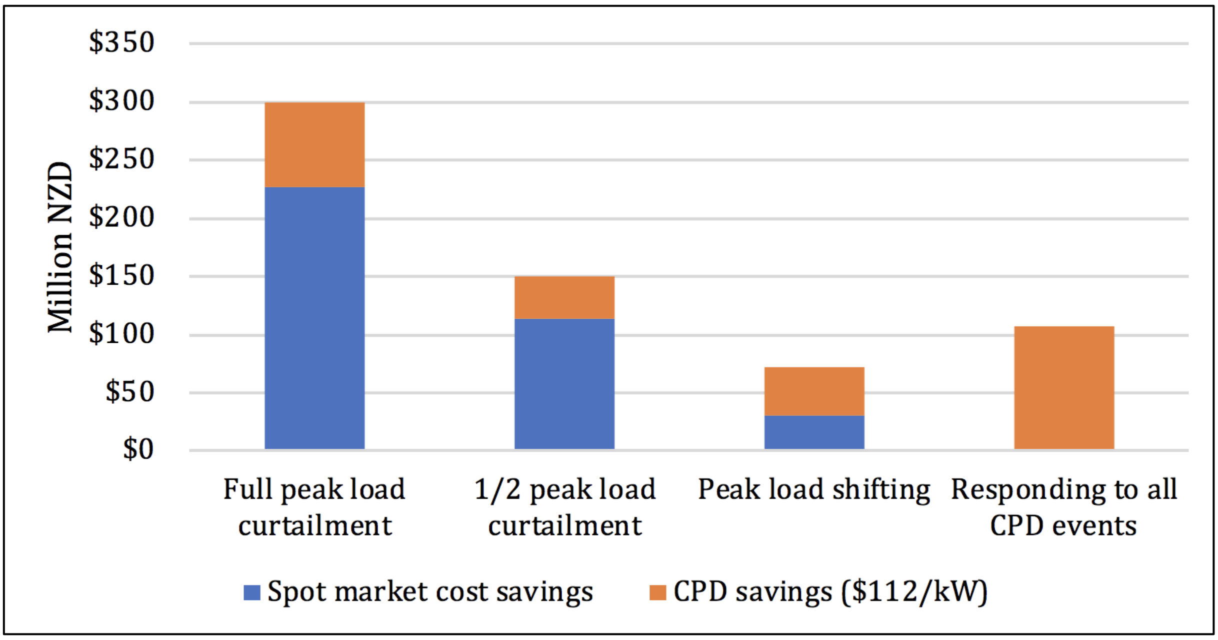

Fig. 47| Savings per year for HP, HW, and REF (scenarios 1-4) assuming 100% hot water unit availability

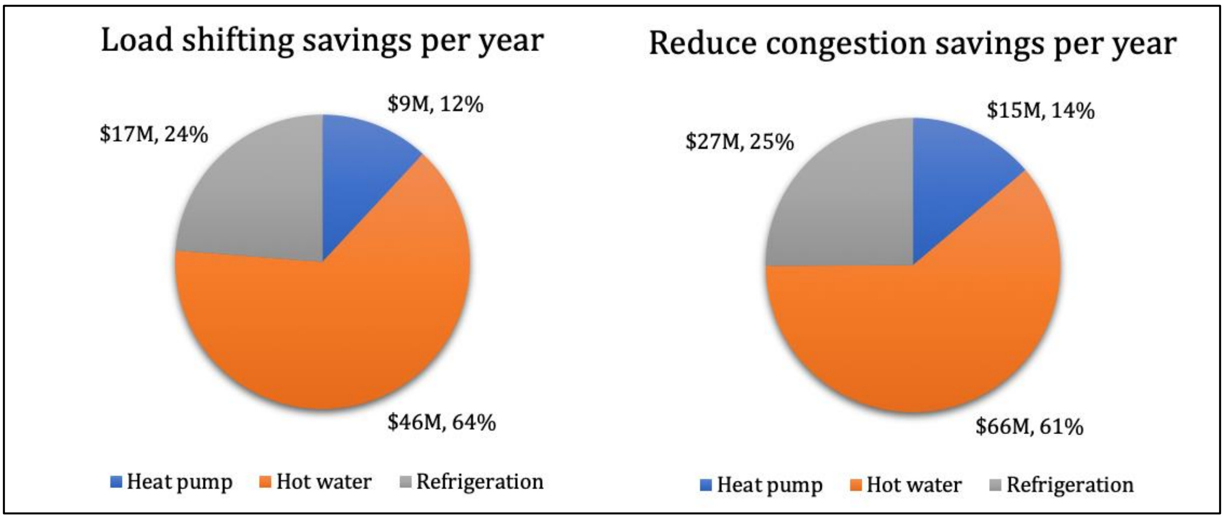

Fig. 48| Left: Peak load shifting savings by appliance per year for HP, HW, and REF. Right: Responding to all CPD events savings by appliance per year for HP, HW, and REF. Both assume 100% hot water unit availability.

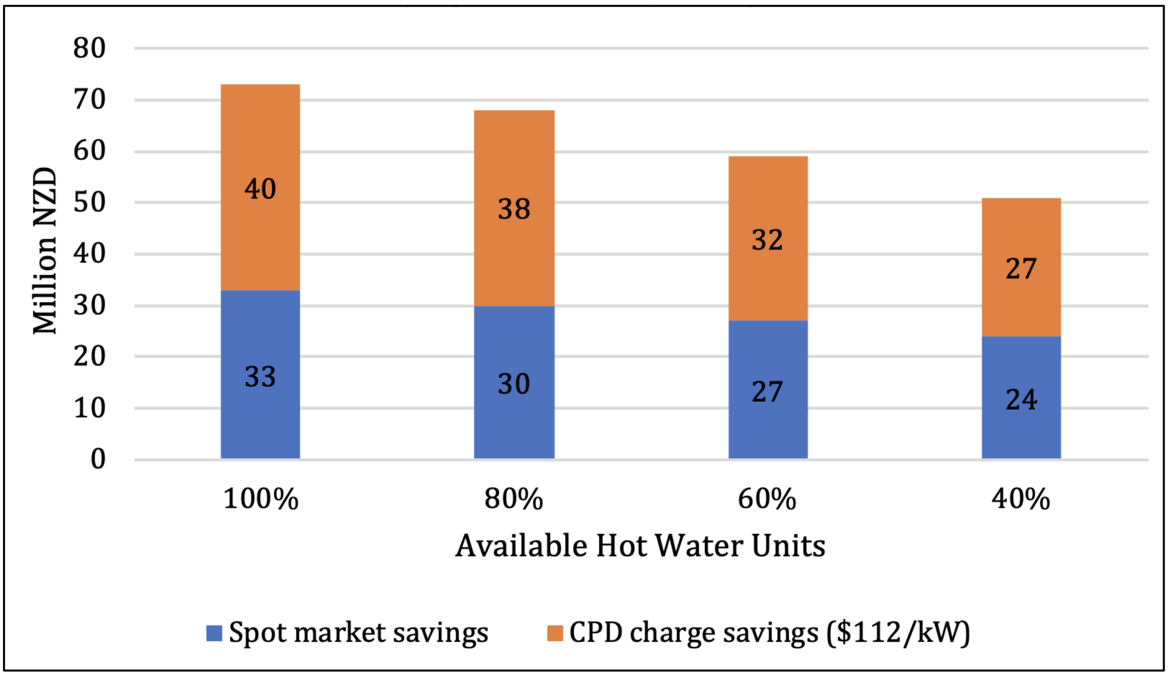

Fig. 49| Potential load shifting savings for HW, HP, and REF per year for different HW unit % availabilities

5.4 Economic value of energy efficient lighting

As with the economic analysis of DR scenarios, this section applies spot market prices and CPD charges to the energy forecast of residential lighting in households, as estimated in section 5.2. An essential assumption in this economic analysis of EE is that economic input data, such as spot market prices and CPD charges, do not alter in years subsequent to 2015 and that this data therefore can be applied on the EE energy forecast (see Assumption 2 of Appendix 1, p. 118). As the analysis of EE does not incorporate DR scenarios that differentiate electricity demand over time, such as e.g. load shifting, estimates in this analysis only focus on the economic value of EE over 2015-2029. This multi-annual granularity supports an analysis of the value of an increased uptake of efficient technology, but does not consider alternate demand scenarios over time. In the following, the economic analysis of EE based on spot market prices and CPD charges is presented.

The analysis estimates that the total spot market cost for lighting in residential households is $120M per year in 2015 and it is assumed that the price per kWh does not vary between 2015 and 2029 (monetary savings come simply from the improved overall efficiency in the lighting stock). This is equivalent to an annual cost of $67 per household. These numbers are forecast to decrease to an annual cost of $43M per year in 2029. This is a total cost reduction of 65% associated with spot market prices. Economic output 6 (p.144) details these findings for each analysed year on a national and household level.

Average CPD in 2015 for residential household lighting reaches 0.15 kW per household with an associated total cost of $31 M per year. This value is equivalent to $17 per household under the lowest price scenario of $112.38 per kW and year. In 2029, these charges are estimated to decrease by approximately 65%, equivalent to the proportional reduction of spot market prices mentioned above. Average CPD in 2029 is forecast to decrease to 0.05 kW per household, equivalent to a national cost of $12 M and an individual charge of $6 per household and year. These findings are further visualised in Economic output 7 (p. 144) of Appendix 3.

The combination of spot market prices and CPD charges constitutes an annual national cost of $151M in 2015. This cost is about three times the cost of heat pumps, and half the cost of hot water heaters in the baseline scenario (no DR applied). EE is forecast to significantly reduce energy consumption with a combined total cost reduction (spot market prices and CPD charges) of 65% by 2029. The total annual cost for residential lighting in 2029 is forecast to be $59M comprising of $47M spot market cost and $12M CPD charges. Lighting in residential households is forecast to achieve the lowest costs of the analysed appliances in this work in 2029. Table 11 and Table 12 further detail these results.

Table 11: Annual costs for residential lighting in 2015 and 2029

	Year: 2015	**Year: 2029**
Spot market cost	$120M	$47M
CPD charges	$31M	$12M
TOTAL	$151M	$59M

Table 12: Annual savings of energy efficient residential lighting in 2029

	Year: 2015	Year: 2029
Saving of spot market cost	-	$73M
Saving of CPD charges	-	$19M
TOTAL	-	$92M

5.5 Combined power potential and economic value of DR and EE

This section integrates the combined power potential and economic value of DR and EE. The combined results of DR and EE are shown in Table 13. In the following, the results depicted in Table 13 are further elucidated. These results cover most of the estimates calculated in this thesis. The estimation below is based on the methodology presented in section 4.6. Please note that the following estimates consider a hot water unit availability of 100%.

Table 13: Combined results of DR and EE incorporating hot water heaters, heat pumps, refrigeration, and lighting

Scenario	Max. Power reduction at peak demand in winter in		Daily energy reduction during periods of peak demand in winter in		Annual national savings in	
	MW	GW	MWh	GWh	$	$
Load curtailment (Scenario 1)	HW: 1,040 (16%)	Total: 2.3 (34%)	HW: 6,100 (13%)	Total: 12.7 (26%)	HW: 176M	Total: 392M
	HP: 320 (4%)		HP: 2,000 (4%)		HP: 47M	
	REF: 240 (3%)		REF: 2,160 (4%)		REF: 77M	
	LIGHT[1]: 780 (12%)		LIGHT[2]: 2,460 (5%)		LIGHT[2]: 92M	
Halved load curtailment (Scenario 2)	HW: 520 (8%)	Total: 1.1 (17%)	HW: 3,050 (6%)	Total: 7.6 (13%)	HW: 88M	Total: 241M
	HP: 160 (2%)		HP: 1,000 (2%)		HP: 23M	
	REF: 120 (2%)		REF: 1,080 (2%)		REF: 38M	
	LIGHT[1]: 390 (6%)		LIGHT[2]: 2,460 (5%)		LIGHT[2]: 92M	

Load shifting (Scenario 3)	HW: 1,040 (16%)	Total: 2.3 (34%)	HW: 6,100 (13%)	Total: 12.7 (26%)	HW: 46M	Total: 164M
	HP: 320 (4%)		HP: 2,000 (4%)		HP: 9M	
	REF: 240 (3%)		REF: 2,160 (4%)		REF: 17M	
	LIGHT: 780 (12%)		LIGHT^2: 2,460 (5%)		LIGHT^2: 92M	
Reduce congestion (Scenario 4)	*not addressed*		*not addressed*		HW, HP, REF: 108M	Total: 200M
					LIGHT^2: 92M	

Abbreviations:

- LIGHT^1: This is the lighting demand in 2015;
- LIGHT^2: These are the savings that are forecast in 2029 (energy-efficient lighting) compared to 2015;
- HW: Hot water heating;
- HP: Heat pump;
- REF: Refrigeration;
- LIGHT: Lighting;
- M: Million NZD

The first column of Table 13 incorporates Scenarios 1 to 3, which were used in the analysis on DR. In addition, Scenario 4 (reducing congestion) is added, to provide an alternative to load curtailment. It is worth mentioning again that load curtailment under Scenario 4 would only apply around 100 hours per year, whereas Scenario 1 affects the predefined times of peak demand every day.

The second column depicts the maximum power of each appliance at the winter evening peak that can potentially be reduced. The percentages in brackets refer to the proportion of maximum national demand in the winter evening peak. For instance, the maximum power of hot water heaters is 1,040 MW. This is equivalent to 16% of the peak in the averaged national winter peak demand (this assumes that the maximum power of hot water occurs at the peak of peak demand, see Fig. 11). These estimates are based on 2015 demand data and do not incorporate energy-efficient lighting. The appliances are individually stated, and a total is calculated next to the column. Scenarios 1 and 4 take on the same values, as in both cases load is fully curtailed at times of peak demand. The maximum demand reduction in winter was not calculated for Scenario 4. This is because the focus of Scenario 4 is on the economic value compared to Scenario 1.

Combining DR and EE maximum power potential attains an overall maximum demand reduction in winter of 2.3 GW for Scenarios 1 and 3, and 1.6 GW for Scenario 2, respectively. This equates to an aggregated proportion of national demand of 34% under Scenario 1 and 3, and 17% under Scenario 2.

Daily energy reduction potentials during periods of peak demand are shown in column three. Scenarios 1 and 3 take on the same value. On an average day in winter, 12.7 GWh can potentially be reduced through DR and EE linked to Scenario 1 and 3. Under Scenario 2 this reduces to a total of 7.6 GWh per day. The energy consumption of hot water heaters, heat pumps, and refrigeration, in addition to the energy savings through energy-efficient lighting, accounts for 26% of national electricity generation under Scenario 1 and 3, and 13% under Scenario 2. Potential energy reduction associated with Scenario 4 was not estimated.

Combined annual national savings are presented in column four. Scenario 1 simply reduces electricity demand and reaches an economic value of $392M when combined with savings from energy efficient lighting. Under Scenario 2, the economic value linked to DR is halved and decreases the economic value to $241M when savings from EE are added. Load shifting under Scenario 3 generates a combined economic value of $164M per year whereas Scenario 4 generates slightly larger savings of $200M.

6. Discussion

This chapter is divided into three sections. The first section brings together the main estimates from the analysis. The second section elucidates limitations of this study in addition to Appendix 1. Future work is presented in section three.

6.1 Overall findings

The analysis shows that residential appliances, including hot water heaters, lighting, heat pumps, and refrigeration represent a significant proportion of electricity demand during network peak demand (see Fig. 10 of section 3.2). Table 14 shows the central estimates achieved by this study regarding the technical potential of daily power and energy reduction and shifting of residential DSM in New Zealand.

Table 14: Overview of daily power and energy potential of analysed DSM mechanisms (DR and EE)

Appliance	*Season*	*Period*	*Max Power Reduction*	*Max Energy Reduction/Shift*	*Related Figure*
Heat Pump	Winter	Morning Peak	320 MW	880 MWh	Fig. 28
		Evening Peak	280 MW	1,140 MWh	
	Summer	Morning Peak	40 MW	120 MWh	
		Evening Peak	80 MW	310 MWh	
Hot Water Heater	Winter	Morning Peak	1,040 MW	3,300 MWh	Fig. 30
		Evening Peak	700 MW	2,800 MWh	
	Summer	Morning Peak	600 MW	1,880 MWh	
		Evening Peak	450 MW	1,740 MWh	
Refrigeration	Winter	Morning Peak	240 MW	1,080 MWh	Fig. 32
		Evening Peak	240 MW	1,080 MWh	
	Summer	Morning Peak	240 MW	1,080 MWh	
		Evening Peak	240 MW	1,080 MWh	
Lighting in 2015	Winter	Morning Peak	540 MW	1,200 MWh	Fig. 42
		Evening Peak	780 MW	2,800 MWh	
	Summer	Morning Peak	250 MW	640 MWh	
		Evening Peak	500 MW	920 MWh	

Hot water heaters, lighting, heat pumps, and refrigerators accounted for an estimated 3,300 MWh, 1,240 MWh, 880 MWh, and 1,080 MWh, respectively for an average day of the winter morning peak from 06:00 to 10:00. The evening peak in winter is 2,810 MWh for hot water heaters, 2,810 MWh for lighting, 1,140 MWh for heat pumps, and 1,080 MWh for refrigerators for an average day, respectively. It should be noted that equivalent maximum power reduction of two periods does not necessarily result in the same amount of shiftable energy. For example, the winter evening peak of hot water heaters and lighting constitutes an energy consumption of 2,800 MWh in both instances. However, maximum power reduction is 700 MW for hot water heaters and 780 MW for lighting. This is because the demand pattern of both appliances is distinctive and results in different maximum demand. Energy consumption over the whole time period of the evening peak in winter does, however, generate the same number of 2,800 MWh.

Three DR scenarios consisted of: full load curtailment, halved load curtailment, and load shifting at times of peak demand. These scenarios show that DR (incorporating residential hot water heaters, heat pumps, and refrigeration) can reduce load during the winter morning peak period by 20% and by 18% in the evening, assuming a 100% availability of hot water units for DR. This represents an average energy consumption of 5,260 MWh in the winter morning peak per day, equivalent to running Huntly Power Station, the largest thermal power station in New Zealand, with an installed capacity of 953 MW, for 5.5 hours at maximum capacity. In the evening peak, this load reduction constitutes 5,030 MWh per day under a 100% availability of hot water units. On a per household level this equates to 3.3 kWh in the winter morning peak and 3.2 kWh in evening peak.

In the summer, less utilisation of heat pumps at peak demand in the morning decreases this proportion to 15% and 14% in the evening. In combination, the appliances modelled could provide a maximum aggregated DR of 1,600 MW in the winter morning peak, and 1,200 MW in the evening peak.

An additional scenario (Scenario 4) considered the reduction of electricity demand at times of congestion periods (see section 5.1.4). The analysis shows, that under a 100% hot water unit availability, the aggregation of hot waters heaters, heat pumps, and refrigeration can provide up to 900 MW DR. In contrast, Transpower's DR programme for 2013 only made available 134 MW in total from all sources, or just 8% (11%) of the technical potential that has been estimated in the winter morning (evening) peak. Further, even Transpower's proposed 635 MW from both industrial and residential DR (Transpower New Zealand Limited, 2014) would still only offer circa 40% of the technical potential that was estimated.

A sensitivity analysis incorporated a range of hot water units, as the availability of residential hot water units available for providing DR in New Zealand is not clear. Estimates show that the DR potential of connected hot water, heat pump, and refrigeration demand decreases from 20% to 13% of national demand in the winter evening peak, assuming that only 40% of hot water units can be utilised for DR. In the winter morning peak, DR potential is reduced from 18% to 12% of national demand under 40% hot water unit availability. These results demonstrate the impact of hot water unit availability on the estimation of DR potentials. Further research is needed to clarify the proportion of hot water systems that are currently ripple controlled.

DR can be suitable with thermo-electric appliances which have the ability to store warm water or warm/cold air, such as hot water heaters, heat pumps and refrigeration. However, applying DR mechanisms such as load curtailment and load shifting on non-thermo-electric appliances is likely to affect the purpose of these appliances. Lighting in residential households was utilised to demonstrate the ability of non-thermo-electric appliances to provide a reduction in electricity demand (and thus peak demand) by incorporating EE measures such as upgrading to more efficient technologies (e.g. light bulbs). This EE analysis was based on the RBS and its forecast on stock proportions by technology. A scale factor enabled the utilisation of both RBS data on residential lighting, and Energy End Use Database data on overall electricity consumption to be applied on the forecast of EE. Unlike the technical assessment in DR scenarios, the RBS is a projection of likely developments in future. The benefit of using this projection instead of developing scenarios such as a LED penetration of 100% is that the RBS includes a variety of lighting technologies and thus provides a more holistic approach. Furthermore, the RBS provides a notion on the possible outcomes that could be attained if appropriate policies, such as the promotion of EE in residential households, were in place.

It is estimated that the stark uptake of light-emitting diodes, combined with a reduction of less efficient incandescent and compact fluorescent lights, will reduce lighting energy consumption in residential households from 1,600 GWh per year in 2015 to 600 GWh in 2030. This is a reduction of approximately 65%. The annual total energy consumption in GWh of lighting was applied on GridSpy monitored average demand profiles and investigated electricity demand throughout the day. The analysis showed that peak electricity demand in winter was 540 MW in the morning and 780 MW in the evening. In the evening, this demand is forecast to decrease to 280 MW in 2029, a reduction of 65%. Energy consumption during the period of peak demand per day in 2015 is estimated to be approximately 1.2 GWh in the winter morning and 2.8 GWh in the evening. EE is forecast to reduce daily energy consumption to 490 MWh in the winter morning and 1,200 MWh in the evening. Through energy-efficient lighting, based on 2029 demand, daily energy savings in winter are 2,460 MWh compared to the baseline energy consumption in 2015 (see section 5.2).

Concurrent with DR, EE has the ability to reduce peak electricity demand and, therefore, electricity generation in New Zealand. The analysis concluded that EE of residential lighting will by the year 2029 decrease electricity generation in New Zealand by up to 9% (equivalent to 500 MW) in the winter evening compared to 2015.

An estimate of the value of these DR scenarios was also attempted. For this estimate, current spot market prices were used as a proxy for time-varying prices and CPD charges as a proxy for critical peak charges. These were the only prices considered. Spot market prices vary over time and season. The highest spot market prices are found in winter and take on values of up to $150 per MWh whereas in summer they remain below $60 per MWh. Spot market prices also vary significantly by region, but this has not been considered in this analysis. CPD charges were also considered as part of estimating the economic value of the DR scenarios. CPD charges are based on the demand (in kW) during congestion periods. In the data utilized, CPD events occur only in autumn and winter, often at times of peak demand. The total duration of CPD events is fourteen hours in an average autumn, and eighty-two hours in an average winter.

Applying these charges to the baseline scenario without DR results in a cost of $540M per year in total, with CPD making up 25%. The load shifting scenario results in a saving of $33M in spot market prices and $40M in CPD charges relative to the baseline. This is equivalent to a total cost reduction of 11% per year.

Concurrent to a decrease of DR potentials caused by a decrease in hot water unit availability, the analysis showed that economic value of DR decreases under less hot water unit availability as well. Under the load shifting scenario (Scenario 3), the total saving of $73M per year is reduced to $51M assuming that only 40% of the hot water units can be used for DR (see Fig. 49). An additional scenario consisting of all participants curtailing load during all CPD events (approximately 100 hours per year) was implemented. This resulted in saving all the CPD charges, equivalent to $108M per year.

The economic value of EE estimated an average CPD of 0.15 kW for residential lighting in 2015 and 0.05 kW in 2029. This CPD, connected with spot market prices, constitutes total annual costs of $151M in 2015. These costs are forecast to decrease by 65% in 2029 due to less energy consumption of residential lighting linked to increasing EE of residential lighting. In 2029, lighting in residential households is estimated to have the lowest annual costs of all analysed appliances in this work (based on the costs of hot water heaters, heat pumps, and refrigeration in 2015).

Estimates on the combined technical potential of DR and EE show that the maximum power potential increases from 1.6 GW (solely DR) to 2.3 GW (34% of national peak demand) when lighting, based on 2015 demand, is added. Concurrently, possible daily average energy reduction in winter increases from 10 GWh to 12.7 GWh (26% of electricity generation during times of peak demand in winter) when energy efficient lighting is incorporated. These estimates assume a hot water unit availability of 100%. The combined economic value is determined by DR scenarios and the methodology associated with them. Load curtailment under Scenario 1, in combination with saved demand due to more energy efficient lighting, generates an annual saving of $392M. Halved load curtailment (Scenario 2) affects the DR economic component and decreases the overall savings to $241M per year. The aforementioned $72M of savings from DR linked to load shifting more than doubles, to $164M per year when the national economic savings of energy-efficient lighting are added. In contrast, annual savings due to DR Scenario 4 (reduce congestion) increases from $108M to $200M when energy-efficient lighting is added. Furthermore, the aggregated impact of all four appliances, considering demand in 2015, increases to 30% of total electricity demand (see sections 5.4 and 5.5). DR applied on hot water heaters and EE applied on residential lighting is most beneficial in this analysis and generates the largest potentials of both demand reduction and electricity generation of the analysed appliances. However, higher investment costs for shifting to more efficient technologies might decrease the total cost savings from reduced electricity use.

The following table summarises these findings in addition to Table 13 of section 5.5:

Table 15: Summary of combined results of DR and EE incorporating hot water heaters, heat pumps, refrigeration, and lighting

Scenario	**Max. Power reduction at peak demand in winter**	**Daily energy reduction during periods of peak demand in winter**	**Annual national savings[4]**
Load curtailment (Scenario 1)	2.3 GW (34%)	12.7 GWh (26%)	$392M
Halved load curtailment (Scenario 2)	1.1 GW (17%)	6.3 GWh (13%)	$241M
Load shifting (Scenario 3)	2.3 GW (34%)	12.7 GWh (26%)	$164M
Reduce congestion (Scenario 4)	*not addressed*	*not addressed*	$200M

6.2 Limitations

The reported technical potential of DR and EE estimated in this study is based on a number of simplifying assumptions taken from currently available data. The most important assumptions made in this work that could directly affect the DR scenarios are:

- That GREENGrid data provides reasonably representative daily profiles for energy use by heat pumps, lights, and hot water cylinders in New Zealand households. This assumption provides the foundation for scaling these GREENGrid demand

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[4] Based on an assumed hot water unit availability of 100%.

profiles to the national level, encompasses regional differences in electricity demand.

- That the BRANZ HEEP study's information on appliances reflects current energy consumption patterns in New Zealand (e.g. that the figure of 88% hot water heaters utilising electricity in New Zealand reported in 2007 based on 1996 Census data is still up to date).

- That EECA's Energy End Use data for 2015 for heat pump, hot water demand and refrigeration is accurate and also there is no significant temporal variation in energy demand for refrigeration;

- That there is no significant variation in regional residential demand throughout New Zealand;

- That the RBS forecasts the development of energy-efficient lighting in households correctly and can be utilised to estimate the power potential and economic value of EE.

Further assumptions are presented in Appendix 1.

These assumptions limit the accuracy of the results. Improved data sources that can provide robust energy demand statistics for a nationally and regionally representative sample of New Zealand households would significantly improve the accuracy of these estimates.

Another limitation of this work is attributed to the incorporation of mean electricity demand profiles. As stated in section 4.2.1, this work assumes that the mean is a good representation of the data provided by GridSpy monitored appliances in residential households. However, there is a loss of data bandwidth connected to mean calculations. High demand that is of interest to the lines company is located at the far-right of the Fig. 18 density plot at around 4,000 MW. As electricity infrastructure needs to be able to potentially supply the demand of 4,000 MW, the mean at 1,200 MW peak demand does not provide a good representation and thus limits the estimations in this work.

DR scenarios in the analysis conduct load curtailment and load shifting on a scale that may well be impractical for appliances like heat pumps. The best way to explain this further is by referring to the insights of trials that implemented DSM. Torriti (2012) underlined the difficulties of successfully integrating DSM mechanisms in the residential household sector. His study found that after the implementation of time-of-use pricing in Italy, electricity consumption increased in both off-peak and peak demand periods. Torriti (2012) concludes that demand loads are predominantly determined by the timing of human activities rather than prices. Further trials are necessary to understand the social behaviours towards electricity consumption in households which will significantly affect the implementation of DR and EE in residential households.

The DR scenarios considered were designed to illustrate maximum effects and, are of course, quite simplistic. This links to the findings of the literature review in section 2.3 where limitations of current approaches to estimating the technical potential of residential DSM and the scope of this thesis were highlighted. Real DR strategies are likely to be much more sophisticated, including, for example, methods to smooth the rebound effect and to also be regionally specific. In addition, these results represent the technical potential and do not consider the market systems and consumer behavioural change necessary to actually achieve residential DR in practice. These aspects are likely to reduce the achievable DR. As mentioned before, this study does not aim to estimate the realisable potential of residential DSM, but provides an overview of maximum potential of residential DSM in New Zealand as an initial step for such an exercise.

The method of estimating the economic value of residential DSM in this thesis is also quite simplistic. It used current market prices as a proxy for time-varying prices and uses (from one region) CPD charges as a proxy for national congestion charges. These estimates therefore only provide a guideline for the value of residential DR.

6.3 Future work

The results presented in this thesis are based on the electricity demand patterns of a small sample of New Zealand households. Future work should ensure a New Zealand representative sample of households and it should also ensure accurate and current statistics on the prevalence of relevant appliances.

Ignoring regional effects in both demand profiles and electricity prices (see Appendix 1) was a significant simplification in the analysis. Further work should definitely include and analyse regional variation, as this could prove quite significant. For example, spot market prices have a significant variation by region. Hot water cylinder penetration is also expected to have a lot of variation between the North Island, which has reticulated natural gas, and the South Island, as there are different heat pump penetration and usage patterns, due to different climatic conditions in each region. A regional analysis could, furthermore, incorporate regional temperature characteristics, to determine whether and to what extent DR linked to heat pumps can be applied. Bronski et al. (2015) as well as Dyson et al. (2014) provide a first notion on how this could be performed.

A central simplification in this thesis is the assumption of a hot water unit availability of 100%. A sensitivity analysis illuminated the effects of a range of hot water units on the power potential. However, further work could more closely investigate the present usage of hot water units utilised for DR in New Zealand to more accurately estimate the power potential of hot water heaters.

The conducted study applied DR uniformly on households. Dyson et al. (2014) emphasised that customers most suitable for DR should be prioritised in order to avoid uniform participation in DR programmes. Further work could analyse the sensibility of each household’s daily demand profile to provide DR and then select only those households that generate the highest value for the DR mechanism.

The study focussed on hot water cylinders, heat pumps, refrigeration (DR), and lighting (EE) appliances based on EECA’s overview of delivered electricity, the RBS, BRANZ and Census data, and available monitored appliance data from the GREENGrid project (Anderson et al., 2018; Energy Efficiency and Conservation Authority, 2017a). Further analysis could consider appliances that have potential to significantly affect residential demand profiles (and peak demand) as well, such as resistive electrical heating. Further analysis could furthermore incorporate technologies such as solar photovoltaic, standalone batteries and grid-connected electric vehicles to assess the realisable potential of residential DSM.

Further analyses can also consider the technologies required to actually implement DR at the residential scale and assess whether this type of DR would lead to substantial impact on service provided by appliances (e.g. cooling down of refrigerators during the four-hour load curtailment). This thesis did not examine whether it is technically feasible to shift heat pump and refrigeration for the indicated time of peak demand. Further work could investigate the technical requirements and necessities to implement DR on these appliances.

Market structures and mechanisms do not currently exist to fully realise the potential for residential DSM. The approach to estimate the economic value entails some rudimentary examples of the market structures that might be required. Further work is needed to explore more optimal market mechanisms to engage residential consumers in DSM.

Finally, and perhaps most importantly, this study has not included any consideration of the behavioural change necessary to realise this DSM potential.

7. Conclusion

This chapter concludes the analysis conducted in this thesis and associates the findings with the initial research objectives of section 1.1. These objectives were:

1. To analyse the demand patterns of key residential household appliances that significantly contribute to peak demand.

2. To develop scenarios that reduce and shift electricity demand into times of less demand (off-peak).

3. To estimate the technical potential of DSM to reduce daily peak demand of residential household appliances in New Zealand, and its economic value.

Rising electricity demand in New Zealand is likely to occur simultaneously with an increase of renewable generation, and this will challenge New Zealand's currently centralised electricity supply system. DSM mechanisms are likely to gain in importance and can assist in maintaining the balance of electricity supply and demand by reducing peak demand. Three research objectives aimed to size the technical potential of residential DSM to assist in managing peak demand.

The first research objective entailed an analysis of demand patterns associated with residential household appliances in New Zealand. Analysing the pattern of demand increases an understanding of peak demand contributors. To do this the analysis utilised a number of data sets such as the high-granularity monitored GREENGrid data, EECA data on overall electricity consumption, and residential baseline study data on lighting. Residential hot water heaters, heat pumps, refrigeration, and lighting were analysed, and particularly hot water heater and lighting demand were identified as significant contributors to residential peak demand. Daily variability of the analysed residential household appliance demand has two distinctive periods of peak demand throughout the seasons (note that for refrigeration a flat profile was assumed).

Analysis of the literature showed the need to analyse both power potential and economic value of DSM as part of the technical potential. Estimating the economic value of DR required the analysis of power potentials, as a basis for further calculation, first. Economic parameters such as spot market prices and CPD charges express the potential of DR and EE that is not necessarily revealed by the power potential. While spot market prices and residential demand charges are commonly used to estimate the economic value of DSM (see Bronski et al., (2015) and Palmer et al., (2013)), the incorporation of CPD charges is not prevalent in recent literature. However, CPD charges, in connection with spot market prices, enabled a more holistic analysis of the economic value in this thesis.

A development of scenarios which reduce and shift electricity demand into times of less demand was addressed by the second research objective. This thesis developed and incorporated four simplistic DR scenarios that affect peak demand i.e. load curtailment (Scenario 1), halved load curtailment (Scenario 2), load shifting (Scenario 3), and the reduction of congestion periods (Scenario 4). These scenarios establish a basis for the estimation of the power potential and its economic value associated with residential DSM. The comparison of analyses that concentrated on one appliance compared to multiple appliances clarified the need for incorporating more than one appliance in this study. A more holistic approach is thus provided. Recent literature on related studies such as Bronski et al. (2015) and Palmer et al. (2013) furthermore facilitated the selection of scenarios. A supplementary development of DR scenarios was necessary to match both the characteristics of New Zealand's electricity system and the available databases.

The preliminary two steps, the analysis of demand patterns on the one hand, and the development of DR scenarios on the other, proceeded to the third research question i.e. the estimation of the technical potential of residential DSM in New Zealand. This estimation addressed both power potential and economic value of residential DSM. Findings are summarised in Table 15.

The technical potential of residential DSM in New Zealand has not been estimated before. Findings of this study can thus not be compared with existing studies. However, Bronski et al. (2015) indicates that approximately 8% of peak electricity demand in the United States of America could be reduced through demand flexibility that does not compromise comfort and service quality. Palmer et al. (2013) estimate a power potential to reduce peak demand in the United Kingdom by up to 30%. In this thesis, peak demand of the analysed appliances has an impact of up to 30% on national electricity demand in winter, when residential lighting demand of 2015 is considered. This ratio decreases to 25% when energy-efficient lighting (on the basis of lighting demand in 2029) is used. A central assumption in this context is a hot water unit availability of 100%. The impact on comfort, service quality or regional variability is not considered in these estimates.

While studies such as Dyson (2014) and Arteconi (2013) enhance their studies' robustness by extending the granularity of the analysis (i.e. considering regional variability and temperature interference on space conditioning), this thesis was time-limited and dependent on available data. In this context, the GridSpy data set does not provide a large enough sample size to be considered as representative for residential households. More accurate results could be achieved with a more representative set of households monitored at appliance level over at least a year.

In conjunction with DR, EE also has the potential for reducing electricity demand. The analysis of lighting in residential households constitutes one of the research objectives presented in section 1.1. EE was utilised as a complementary mechanism of DSM that is strongly connected to the aims of DR. Policies around EE in New Zealand support the instalment of more efficient technologies. The analysis on EE showed, that these policies, connected to residential lighting, could especially reduce electricity peak demand in the evenings of autumn and winter by up to 9%.

This thesis undertakes a first attempt to size the technical potential of residential DSM in New Zealand and aims to address the lack of research connected to the technical potential that is identified in section 2.2. This technical potential entails an estimate of the maximum power potential and economic value that residential DSM can achieve. This does not reflect the realisable potential, which for hot water heaters, heat pumps, lighting, and refrigeration will require more research to understand the readiness of New Zealand households to engage in EE measures, demand reduction and/or shifting at peak times, and the barriers and incentives to do so.

The findings presented in this thesis contribute to a better understanding of DSM in the New Zealand’s electricity system. These findings have implications for a variety of stakeholders such as the system operator, lines companies, and residential electricity customers. DSM successfully implemented helps to:

- Reduce electricity peak demand;
- Reduce electricity network congestion in autumn and winter;
- Avoid investment in new electricity infrastructure;
- Provide monetary benefits to residential electricity customers;
- Facilitate a successful low-carbon energy transition.

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Appendix 1: Assumptions

Assumption 1: Pertaining DR scenarios, EE, and power potentials

1. GREENGrid data is sufficiently representative of New Zealand households (including regional variability of demand).
2. BRANZ information of appliances are correct and can be used to display current energy consumption patterns in New Zealand (e.g. the 1996 figure of 88% hot water heaters utilising electricity in New Zealand is still up to date).
3. BRANZ values for total energy consumption of appliances are preferred to those from EECA. This prevents overestimation of results.
4. Census 2013 is a sufficient representation of current New Zealand households.
5. Incorporation of two different sources of information on the total number of households in New Zealand is unproblematic. (BRANZ reports distinguish number of households in reports of hot water heaters and heat pumps. See section 4.2)
6. Determination of peak time intervals based on electricity generation is accurate.
7. Seasonal load average (1min granularity) of GREENGrid dataset represents the correct proportion of load for all households in New Zealand when converted to half hour proportion and scaled to BRANZ/EECA total energy consumption in GWh.
8. Load shifting to a time prior to peak demand is feasible and equivalent of pre-heating (hot water heaters, heat pumps) and pre-cooling (refrigerators).
9. Estimates on electricity generation can be drawn from one month of data in the middle of the season (trading granularity only available for up to one month).
10. Absence of measured appliance data (refrigerators) is replaced with a flat energy consumption profile representing in sum the total energy consumption for the individual appliance based on EECA data for 2015.
11. SC1 load curtailment: Curtailed energy consumption can be reduced without any effects on the consumption in other times.
12. SC2 ½ load curtailment: Energy consumption at peaks can be halved without having effects on other times.
13. SC3 load shifting: Energy consumption at peaks can be shifted in the prior time interval.
14. Scenarios are used to assess the technical potential of DR. The realisable potential will differ from the scenario output.

15. DR for lighting is not permittable as there is no storage ability in light. This study therefore focuses on the development of *power* potential and *economic* value rather than individual scenarios.
16. The RBS forecasts the development of EE in households correctly and can be utilised to estimate the *power* potential and its economic value of EE.
17. The half-hour energy consumption profile mean of the different appliance profiles depicts the profiles correctly and can be utilised to estimate power potential and economic value of DR and EE.
18. It is possible that under Scenario 3 load is shifted where CPD is still occurring (they are not confined to peak periods). We assume that load shifting into CPD events does not have effect on the system.

Assumption 2: Pertaining economic value of DR scenarios and EE

1. Seasonal average of spot market prices for each region represents reality.
2. Spot market prices and CPD charges do not change when load is curtailed or shifted.
3. The electricity price only exists out of two components, spot market prices and CPD charge.
4. Using CPD charge information from Aurora Energy represent New Zealand accurate information on CPD charges.
5. Applying commercial CPD charges on household appliance profiles represent real cost that lines companies face.
6. CPD charge scenarios 1 to 3 incorporate all assumptions from the aforementioned demand response scenarios.
7. In CPD charge scenario 4 households respond to each CPD event.
8. There are no CPD events (hours) in spring and summer.
9. Spot market prices do not change between CPD event and increased energy consumption in CPD scenario 4
10. The economic parameters (spot market prices and CPD charges) do not alternate in the analysis of EE.

Appendix 2: Energy Potential Tables

Energy output 1: HP SC1 total New Zealand per day in MWh

Season	Time-period	Potential curtailment
Spring	Evening Peak	453.20
Spring	Morning Peak	401.21
Spring	Off Peak 1	319.79
Spring	Off Peak 2	284.61
Summer	Evening Peak	308.93
Summer	Morning Peak	120.06
Summer	Off Peak 1	251.19
Summer	Off Peak 2	290.89
Autumn	Evening Peak	447.02
Autumn	Morning Peak	333.43
Autumn	Off Peak 1	329.06
Autumn	Off Peak 2	264.57
Winter	Evening Peak	1143.41
Winter	Morning Peak	879.38
Winter	Off Peak 1	716.47
Winter	Off Peak 2	553.04

Energy output 2: HP SC1 total New Zealand per season in GWh

Season	Time-period	Potential curtailment
Spring	Evening Peak	40.79
Spring	Morning Peak	36.11
Spring	Off Peak 1	28.78
Spring	Off Peak 2	25.61
Summer	Evening Peak	27.80
Summer	Morning Peak	10.81
Summer	Off Peak 1	22.61
Summer	Off Peak 2	26.18
Autumn	Evening Peak	40.23
Autumn	Morning Peak	30.01
Autumn	Off Peak 1	29.62
Autumn	Off Peak 2	23.81
Winter	Evening Peak	102.91
Winter	Morning Peak	79.14
Winter	Off Peak 1	64.48
Winter	Off Peak 2	49.77

Energy output 3: HP SC2 total New Zealand per day in MWh

Season	Time-period	Potential curtailment
Spring	Evening Peak	226.60
Spring	Morning Peak	200.61
Spring	Off Peak 1	319.79
Spring	Off Peak 2	284.61
Summer	Evening Peak	154.46
Summer	Morning Peak	60.03
Summer	Off Peak 1	251.19
Summer	Off Peak 2	290.89
Autumn	Evening Peak	223.51
Autumn	Morning Peak	166.72
Autumn	Off Peak 1	329.06
Autumn	Off Peak 2	264.57
Winter	Evening Peak	571.70
Winter	Morning Peak	439.69
Winter	Off Peak 1	716.47
Winter	Off Peak 2	553.04

Energy output 4: HP SC2 total New Zealand per season in GWh

Season	Time-period	Potential curtailment
Spring	Evening Peak	20.39
Spring	Morning Peak	18.05
Spring	Off Peak 1	28.78
Spring	Off Peak 2	25.61
Summer	Evening Peak	13.90
Summer	Morning Peak	5.40
Summer	Off Peak 1	22.61
Summer	Off Peak 2	26.18
Autumn	Evening Peak	20.12
Autumn	Morning Peak	15.00
Autumn	Off Peak 1	29.62
Autumn	Off Peak 2	23.81
Winter	Evening Peak	51.45
Winter	Morning Peak	39.57
Winter	Off Peak 1	64.48
Winter	Off Peak 2	49.77

Energy output 5: HW SC1 total New Zealand per day in MWh

Season	Time-period	Potential curtailment

Spring	Evening Peak	2584.78
Spring	Morning Peak	3030.24
Spring	Off Peak 1	2020.66
Spring	Off Peak 2	2445.55
Summer	Evening Peak	1742.34
Summer	Morning Peak	1881.78
Summer	Off Peak 1	1636.35
Summer	Off Peak 2	1801.21
Autumn	Evening Peak	2301.47
Autumn	Morning Peak	2797.11
Autumn	Off Peak 1	1790.27
Autumn	Off Peak 2	2425.75
Winter	Evening Peak	2812.70
Winter	Morning Peak	3296.19
Winter	Off Peak 1	2167.42
Winter	Off Peak 2	3068.05

Energy output 6: HW SC1 total New Zealand per season in GWh

Season	Time-period	Potential curtailment
Spring	Evening Peak	232.27
Spring	Morning Peak	272.47
Spring	Off Peak 1	181.15
Spring	Off Peak 2	220.49
Summer	Evening Peak	156.91
Summer	Morning Peak	169.57
Summer	Off Peak 1	147.23
Summer	Off Peak 2	162.66
Autumn	Evening Peak	207.53
Autumn	Morning Peak	251.14
Autumn	Off Peak 1	161.73
Autumn	Off Peak 2	218.14
Winter	Evening Peak	253.97
Winter	Morning Peak	296.42
Winter	Off Peak 1	195.55
Winter	Off Peak 2	276.55

Energy output 7: HW SC2 total New Zealand per day in MWh

Season	Time-period	Potential curtailment
Spring	Evening Peak	1292.39

Spring	Morning Peak	1515.62
Spring	Off Peak 1	2020.66
Spring	Off Peak 2	2445.55
Summer	Evening Peak	871.17
Summer	Morning Peak	940.39
Summer	Off Peak 1	1636.35
Summer	Off Peak 2	1801.21
Autumn	Evening Peak	1150.73
Autumn	Morning Peak	1398.55
Autumn	Off Peak 1	1790.27
Autumn	Off Peak 2	2425.75
Winter	Evening Peak	1406.85
Winter	Morning Peak	1648.09
Winter	Off Peak 1	2167.41
Winter	Off Peak 2	3068.05

Energy output 8: HW SC2 total New Zealand per season in GWh

Season	Time-period	Potential curtailment
Spring	Evening Peak	116.64
Spring	Morning Peak	136.74
Spring	Off Peak 1	181.15
Spring	Off Peak 2	220.49
Summer	Evening Peak	78.96
Summer	Morning Peak	84.78
Summer	Off Peak 1	147.23
Summer	Off Peak 2	162.66
Autumn	Evening Peak	103.27
Autumn	Morning Peak	125.57
Autumn	Off Peak 1	161.73
Autumn	Off Peak 2	218.14
Winter	Evening Peak	126.49
Winter	Morning Peak	148.21
Winter	Off Peak 1	195.55
Winter	Off Peak 2	260.55

Energy output 9: REF SC1 total New Zealand per day in MWh

Season	Time-period	Potential curtailment
Spring	Evening Peak	1080.21
Spring	Morning Peak	1080.21

Spring	Off Peak 1	2040.39
Spring	Off Peak 2	1560.30
Summer	Evening Peak	1080.21
Summer	Morning Peak	1080.21
Summer	Off Peak 1	2040.39
Summer	Off Peak 2	1560.30
Autumn	Evening Peak	1080.21
Autumn	Morning Peak	1080.21
Autumn	Off Peak 1	2040.39
Autumn	Off Peak 2	1560.30
Winter	Evening Peak	1080.21
Winter	Morning Peak	1080.21
Winter	Off Peak 1	2040.39
Winter	Off Peak 2	1560.30

Energy output 10: REF SC1 total New Zealand per season in GWh

Season	Time-period	Potential curtailment
Spring	Evening Peak	97.22
Spring	Morning Peak	97.22
Spring	Off Peak 1	183.64
Spring	Off Peak 2	140.43
Summer	Evening Peak	97.22
Summer	Morning Peak	97.22
Summer	Off Peak 1	183.64
Summer	Off Peak 2	140.43
Autumn	Evening Peak	97.22
Autumn	Morning Peak	97.22
Autumn	Off Peak 1	183.64
Autumn	Off Peak 2	140.43
Winter	Evening Peak	97.22
Winter	Morning Peak	97.22
Winter	Off Peak 1	183.64
Winter	Off Peak 2	140.43

Energy output 11: REF SC2 total New Zealand per day in MWh

Season	Time-period	Potential curtailment
Spring	Evening Peak	540.10

Spring	Morning Peak	540.10
Spring	Off Peak 1	2040.39
Spring	Off Peak 2	1560.30
Summer	Evening Peak	540.10
Summer	Morning Peak	540.10
Summer	Off Peak 1	2040.39
Summer	Off Peak 2	1560.30
Autumn	Evening Peak	540.10
Autumn	Morning Peak	540.10
Autumn	Off Peak 1	2040.39
Autumn	Off Peak 2	1560.30
Winter	Evening Peak	540.10
Winter	Morning Peak	540.10
Winter	Off Peak 1	2040.39
Winter	Off Peak 2	1560.30

Energy output 12: REF SC2 total New Zealand per season in GWh

Season	Time-period	Potential curtailment
Spring	Evening Peak	48.61
Spring	Morning Peak	48.61
Spring	Off Peak 1	183.64
Spring	Off Peak 2	140.43
Summer	Evening Peak	48.61
Summer	Morning Peak	48.61
Summer	Off Peak 1	183.64
Summer	Off Peak 2	140.43
Autumn	Evening Peak	48.61
Autumn	Morning Peak	48.61
Autumn	Off Peak 1	183.64
Autumn	Off Peak 2	140.43
Winter	Evening Peak	48.61
Winter	Morning Peak	48.61
Winter	Off Peak 1	183.64
Winter	Off Peak 2	140.43

Energy output 13: HP&HW SC1 total New Zealand per day in MWh

Season	Time-period	Potential curtailment
Spring	Evening Peak	2933.98

Spring	Morning Peak	3306.45
Spring	Off Peak 1	2221.45
Spring	Off Peak 2	2601.16
Summer	Evening Peak	2041.27
Summer	Morning Peak	2070.84
Summer	Off Peak 1	1831.54
Summer	Off Peak 2	2087.10
Autumn	Evening Peak	2808.49
Autumn	Morning Peak	3190.54
Autumn	Off Peak 1	2048.33
Autumn	Off Peak 2	2688.32
Winter	Evening Peak	3843.11
Winter	Morning Peak	4039.57
Winter	Off Peak 1	2755.88
Winter	Off Peak 2	3448.09

Energy output 14: HP&HW SC1 total New Zealand per season in GWh

Season	Time-period	Potential curtailment
Spring	Evening Peak	264.06
Spring	Morning Peak	297.58
Spring	Off Peak 1	199.93
Spring	Off Peak 2	234.10
Summer	Evening Peak	183.71
Summer	Morning Peak	186.38
Summer	Off Peak 1	164.84
Summer	Off Peak 2	187.84
Autumn	Evening Peak	252.76
Autumn	Morning Peak	287.15
Autumn	Off Peak 1	184.35
Autumn	Off Peak 2	241.95
Winter	Evening Peak	345.88
Winter	Morning Peak	363.56
Winter	Off Peak 1	248.03
Winter	Off Peak 2	310.33

Energy output 15: HP&HW SC2 total New Zealand per day in MWh

Season	Time-period	Potential curtailment
Spring	Evening Peak	1466.99
Spring	Morning Peak	1653.23

Spring	Off Peak 1	4822.61
Spring	Off Peak 2	1020.63
Summer	Evening Peak	1035.42
Summer	Morning Peak	3918.64
Summer	Off Peak 1	1404.24
Summer	Off Peak 2	1595.27
Autumn	Evening Peak	4736.65
Autumn	Morning Peak	1921.56
Autumn	Off Peak 1	2019.78
Autumn	Off Peak 2	6203.97
Winter	Evening Peak	1466.99
Winter	Morning Peak	1653.23
Winter	Off Peak 1	4822.61
Winter	Off Peak 2	1020.63

Energy output 16: HP&HW SC2 total New Zealand per season in GWh

Season	Time-period	Potential curtailment
Spring	Evening Peak	132.03
Spring	Morning Peak	148.79
Spring	Off Peak 1	434.03
Spring	Off Peak 2	91.86
Summer	Evening Peak	93.19
Summer	Morning Peak	352.68
Summer	Off Peak 1	126.38
Summer	Off Peak 2	143.57
Autumn	Evening Peak	426.30
Autumn	Morning Peak	172.94
Autumn	Off Peak 1	181.78
Autumn	Off Peak 2	558.36
Winter	Evening Peak	132.03
Winter	Morning Peak	148.79
Winter	Off Peak 1	434.03
Winter	Off Peak 2	91.86

Energy output 17: HP, HW&REF SC1 total New Zealand per day in MWh

Season	Time-period	Potential curtailment
Spring	Evening Peak	4118.19
Spring	Morning Peak	4512.66
Spring	Off Peak 1	4381.85

Spring	Off Peak 2	4290.46
Summer	Evening Peak	3131.47
Summer	Morning Peak	3081.05
Summer	Off Peak 1	3927.93
Summer	Off Peak 2	3652.40
Autumn	Evening Peak	3828.69
Autumn	Morning Peak	4211.75
Autumn	Off Peak 1	4160.72
Autumn	Off Peak 2	4250.62
Winter	Evening Peak	5036.32
Winter	Morning Peak	5256.78
Winter	Off Peak 1	4924.27
Winter	Off Peak 2	5182.39

Energy output 18: HP, HW&REF SC1 total New Zealand per season in GWh

Season	Time-period	Potential curtailment
Spring	Evening Peak	370.28
Spring	Morning Peak	406.80
Spring	Off Peak 1	394.57
Spring	Off Peak 2	386.53
Summer	Evening Peak	281.93
Summer	Morning Peak	277.59
Summer	Off Peak 1	353.47
Summer	Off Peak 2	328.27
Autumn	Evening Peak	344.98
Autumn	Morning Peak	379.37
Autumn	Off Peak 1	374.99
Autumn	Off Peak 2	382.38
Winter	Evening Peak	453.10
Winter	Morning Peak	473.78
Winter	Off Peak 1	443.66
Winter	Off Peak 2	466.76

Energy output 19: HP, HW&REF SC2 total New Zealand per day in MWh

Season	Time-period	Potential curtailment
Spring	Evening Peak	2059.09
Spring	Morning Peak	2256.33
Spring	Off Peak 1	4381.85
Spring	Off Peak 2	4290.46

Summer	Evening Peak	1565.74
Summer	Morning Peak	1540.52
Summer	Off Peak 1	3927.93
Summer	Off Peak 2	3652.40
Autumn	Evening Peak	1914.35
Autumn	Morning Peak	2105.38
Autumn	Off Peak 1	4160.72
Autumn	Off Peak 2	4250.62
Winter	Evening Peak	2518.66
Winter	Morning Peak	2628.89
Winter	Off Peak 1	4924.27
Winter	Off Peak 2	5182.39

Energy output 20: HP, HW&REF SC2 total New Zealand per season in GWh

Season	Time-period	Potential curtailment
Spring	Evening Peak	185.64
Spring	Morning Peak	203.40
Spring	Off Peak 1	394.57
Spring	Off Peak 2	386.53
Summer	Evening Peak	140.47
Summer	Morning Peak	138.80
Summer	Off Peak 1	353.47
Summer	Off Peak 2	328.27
Autumn	Evening Peak	172.99
Autumn	Morning Peak	189.18
Autumn	Off Peak 1	374.99
Autumn	Off Peak 2	382.38
Winter	Evening Peak	226.55
Winter	Morning Peak	236.39
Winter	Off Peak 1	443.66
Winter	Off Peak 2	466.76

Energy output 21: Daily average lighting energy consumption in MWh for 2015

Year	Season	Time-period	Energy consumption
2015	Spring	Evening Peak	1779.45
2015	Spring	Morning Peak	848.93
2015	Spring	Off Peak 1	884.22
2015	Spring	Off Peak 2	694.58
2015	Summer	Evening Peak	927.27

2015	Summer	Morning Peak	646.17
2015	Summer	Off Peak 1	811.31
2015	Summer	Off Peak 2	586.39
2015	Autumn	Evening Peak	1972.05
2015	Autumn	Morning Peak	912.91
2015	Autumn	Off Peak 1	883.53
2015	Autumn	Off Peak 2	635.13
2015	Winter	Evening Peak	2817.33
2015	Winter	Morning Peak	1238.80
2015	Winter	Off Peak 1	1026.38
2015	Winter	Off Peak 2	857.78

Energy output 22: Seasonal average lighting energy consumption in GWh for 2015

Year	Season	Time-period	Energy consumption
2015	Spring	Evening Peak	160.15
2015	Spring	Morning Peak	76.40
2015	Spring	Off Peak 1	79.58
2015	Spring	Off Peak 2	62.51
2015	Summer	Evening Peak	83.45
2015	Summer	Morning Peak	58.16
2015	Summer	Off Peak 1	73.02
2015	Summer	Off Peak 2	52.77
2015	Autumn	Evening Peak	177.48
2015	Autumn	Morning Peak	82.16
2015	Autumn	Off Peak 1	79.52
2015	Autumn	Off Peak 2	57.16
2015	Winter	Evening Peak	253.56
2015	Winter	Morning Peak	111.49
2015	Winter	Off Peak 1	92.37
2015	Winter	Off Peak 2	77.20

Energy output 23: Daily average lighting energy consumption in MWh for 2017

Year	Season	Time-period	Energy consumption
2017	Spring	Evening Peak	1693.21
2017	Spring	Morning Peak	807.78
2017	Spring	Off Peak 1	841.37
2017	Spring	Off Peak 2	660.91

2017	Summer	Evening Peak	882.33
2017	Summer	Morning Peak	614.85
2017	Summer	Off Peak 1	771.99
2017	Summer	Off Peak 2	557.97
2017	Autumn	Evening Peak	1876.48
2017	Autumn	Morning Peak	868.67
2017	Autumn	Off Peak 1	840.71
2017	Autumn	Off Peak 2	604.35
2017	Winter	Evening Peak	2680.79
2017	Winter	Morning Peak	1178.76
2017	Winter	Off Peak 1	976.64
2017	Winter	Off Peak 2	816.21

Energy output 24: Seasonal average lighting energy consumption in GWh for 2017

Year	Season	Time-period	Energy consumption
2017	Spring	Morning Peak	72.70
2017	Spring	Off Peak 1	75.72
2017	Spring	Off Peak 2	59.48
2017	Summer	Evening Peak	79.41
2017	Summer	Morning Peak	55.34
2017	Summer	Off Peak 1	69.48
2017	Summer	Off Peak 2	50.22
2017	Autumn	Evening Peak	168.88
2017	Autumn	Morning Peak	78.18
2017	Autumn	Off Peak 1	75.66
2017	Autumn	Off Peak 2	54.39
2017	Winter	Evening Peak	241.27
2017	Winter	Morning Peak	106.09
2017	Winter	Off Peak 1	87.90
2017	Winter	Off Peak 2	73.46

Energy output 25: Daily average lighting energy consumption in MWh for 2019

Year	Season	Time-period	Energy consumption
2019	Spring	Morning Peak	735.46
2019	Spring	Off Peak 1	766.04
2019	Spring	Off Peak 2	601.74
2019	Summer	Evening Peak	803.33

2019	Summer	Morning Peak	559.80
2019	Summer	Off Peak 1	702.87
2019	Summer	Off Peak 2	508.01
2019	Autumn	Evening Peak	1708.47
2019	Autumn	Morning Peak	790.89
2019	Autumn	Off Peak 1	765.44
2019	Autumn	Off Peak 2	550.24
2019	Winter	Evening Peak	2440.77
2019	Winter	Morning Peak	1073.22
2019	Winter	Off Peak 1	889.20
2019	Winter	Off Peak 2	743.13

Energy output 26: Seasonal average lighting energy consumption in GWh for 2019

Year	Season	Time-period	Energy consumption
2019	Spring	Evening Peak	138.75
2019	Spring	Morning Peak	66.19
2019	Spring	Off Peak 1	68.94
2019	Spring	Off Peak 2	54.16
2019	Summer	Evening Peak	72.30
2019	Summer	Morning Peak	50.38
2019	Summer	Off Peak 1	63.26
2019	Summer	Off Peak 2	45.72
2019	Autumn	Evening Peak	153.76
2019	Autumn	Morning Peak	71.18
2019	Autumn	Off Peak 1	68.89
2019	Autumn	Off Peak 2	49.52
2019	Winter	Evening Peak	219.67
2019	Winter	Morning Peak	96.59
2019	Winter	Off Peak 1	80.03
2019	Winter	Off Peak 2	66.88

Energy output 27: Daily average lighting energy consumption in MWh for 2021

Year	Season	Time-period	Energy consumption
2021	Spring	Evening Peak	1350.14
2021	Spring	Morning Peak	644.11
2021	Spring	Off Peak 1	670.89
2021	Spring	Off Peak 2	527.00

2021	Summer	Evening Peak	703.55
2021	Summer	Morning Peak	490.27
2021	Summer	Off Peak 1	615.57
2021	Summer	Off Peak 2	444.91
2021	Autumn	Evening Peak	1496.27
2021	Autumn	Morning Peak	692.66
2021	Autumn	Off Peak 1	670.37
2021	Autumn	Off Peak 2	481.90
2021	Winter	Evening Peak	2137.62
2021	Winter	Morning Peak	939.92
2021	Winter	Off Peak 1	778.75
2021	Winter	Off Peak 2	650.83

Energy output 28: Seasonal average lighting energy consumption in GWh for 2021

Year	Season	Time-period	Energy consumption
2021	Spring	Morning Peak	57.97
2021	Spring	Off Peak 1	60.38
2021	Spring	Off Peak 2	47.43
2021	Summer	Evening Peak	63.32
2021	Summer	Morning Peak	44.12
2021	Summer	Off Peak 1	55.40
2021	Summer	Off Peak 2	40.04
2021	Autumn	Evening Peak	134.66
2021	Autumn	Morning Peak	62.34
2021	Autumn	Off Peak 1	60.33
2021	Autumn	Off Peak 2	43.37
2021	Winter	Evening Peak	192.39
2021	Winter	Morning Peak	84.59
2021	Winter	Off Peak 1	70.09
2021	Winter	Off Peak 2	58.57

Energy output 29: Daily average lighting energy consumption in MWh for 2023

Year	Season	Time-period	Energy consumption
2023	Spring	Evening Peak	1157.71
2023	Spring	Morning Peak	552.31
2023	Spring	Off Peak 1	575.27
2023	Spring	Off Peak 2	451.89

2023	Summer	Evening Peak	603.28
2023	Summer	Morning Peak	420.40
2023	Summer	Off Peak 1	527.83
2023	Summer	Off Peak 2	381.50
2023	Autumn	Evening Peak	1283.01
2023	Autumn	Morning Peak	593.94
2023	Autumn	Off Peak 1	574.82
2023	Autumn	Off Peak 2	413.21
2023	Winter	Evening Peak	1832.94
2023	Winter	Morning Peak	805.96
2023	Winter	Off Peak 1	667.76
2023	Winter	Off Peak 2	558.07

Energy output 30: Seasonal average lighting energy consumption in GWh for 2023

Year	Season	Time-period	Energy consumption
2023	Spring	Evening Peak	104.19
2023	Spring	Morning Peak	49.71
2023	Spring	Off Peak 1	51.77
2023	Spring	Off Peak 2	40.67
2023	Summer	Evening Peak	54.29
2023	Summer	Morning Peak	37.84
2023	Summer	Off Peak 1	47.50
2023	Summer	Off Peak 2	34.34
2023	Autumn	Evening Peak	115.47
2023	Autumn	Morning Peak	53.45
2023	Autumn	Off Peak 1	51.73
2023	Autumn	Off Peak 2	37.19
2023	Winter	Evening Peak	164.96
2023	Winter	Morning Peak	72.54
2023	Winter	Off Peak 1	60.10
2023	Winter	Off Peak 2	50.23

Energy output 31: Daily average lighting energy consumption in MWh for 2025

Year	Season	Time-period	Energy consumption
2025	Spring	Evening Peak	982.54
2025	Spring	Morning Peak	468.74
2025	Spring	Off Peak 1	488.23

2025	Spring	Off Peak 2	383.52
2025	Summer	Evening Peak	512.00
2025	Summer	Morning Peak	356.79
2025	Summer	Off Peak 1	447.97
2025	Summer	Off Peak 2	323.78
2025	Autumn	Evening Peak	1088.88
2025	Autumn	Morning Peak	504.07
2025	Autumn	Off Peak 1	487.85
2025	Autumn	Off Peak 2	350.69
2025	Winter	Evening Peak	1555.61
2025	Winter	Morning Peak	684.01
2025	Winter	Off Peak 1	566.72
2025	Winter	Off Peak 2	473.63

Energy output 32: Seasonal average lighting energy consumption in GWh for 2025

Year	Season	Time-period	Energy consumption
2025	Spring	Evening Peak	88.43
2025	Spring	Morning Peak	42.19
2025	Spring	Off Peak 1	43.94
2025	Spring	Off Peak 2	34.52
2025	Summer	Evening Peak	46.08
2025	Summer	Morning Peak	32.11
2025	Summer	Off Peak 1	40.32
2025	Summer	Off Peak 2	29.14
2025	Autumn	Evening Peak	98.00
2025	Autumn	Morning Peak	45.37
2025	Autumn	Off Peak 1	43.91
2025	Autumn	Off Peak 2	31.56
2025	Winter	Evening Peak	140.00
2025	Winter	Morning Peak	61.56
2025	Winter	Off Peak 1	51.00
2025	Winter	Off Peak 2	42.63

Energy output 33: Daily average lighting energy consumption in MWh for 2027

Year	Season	Time-period	Energy consumption
2027	Spring	Morning Peak	395.28
2027	Spring	Off Peak 1	411.71

2027	Spring	Off Peak 2	323.41
2027	Summer	Evening Peak	431.75
2027	Summer	Morning Peak	300.87
2027	Summer	Off Peak 1	377.76
2027	Summer	Off Peak 2	273.03
2027	Autumn	Evening Peak	918.22
2027	Autumn	Morning Peak	425.07
2027	Autumn	Off Peak 1	411.39
2027	Autumn	Off Peak 2	295.73
2027	Winter	Evening Peak	1311.80
2027	Winter	Morning Peak	576.81
2027	Winter	Off Peak 1	477.90
2027	Winter	Off Peak 2	399.40

Energy output 34: Seasonal average lighting energy consumption in GWh for 2027

Year	Season	Time-period	Energy consumption
2027	Spring	Evening Peak	74.57
2027	Spring	Morning Peak	35.57
2027	Spring	Off Peak 1	37.05
2027	Spring	Off Peak 2	29.11
2027	Summer	Evening Peak	38.86
2027	Summer	Morning Peak	27.08
2027	Summer	Off Peak 1	34.00
2027	Summer	Off Peak 2	24.57
2027	Autumn	Evening Peak	82.64
2027	Autumn	Morning Peak	38.26
2027	Autumn	Off Peak 1	37.02
2027	Autumn	Off Peak 2	26.62
2027	Winter	Evening Peak	118.06
2027	Winter	Morning Peak	51.91
2027	Winter	Off Peak 1	43.01
2027	Winter	Off Peak 2	35.95

Energy output 35: Daily average lighting energy consumption in MWh for 2029

Year	Season	Time-period	Energy consumption
2029	Spring	Evening Peak	701.24

2029	Spring	Morning Peak	334.54
2029	Spring	Off Peak 1	348.45
2029	Spring	Off Peak 2	273.72
2029	Summer	Evening Peak	365.42
2029	Summer	Morning Peak	254.64
2029	Summer	Off Peak 1	319.72
2029	Summer	Off Peak 2	231.08
2029	Autumn	Evening Peak	777.14
2029	Autumn	Morning Peak	359.76
2029	Autumn	Off Peak 1	348.18
2029	Autumn	Off Peak 2	250.29
2029	Winter	Evening Peak	1110.25
2029	Winter	Morning Peak	488.18
2029	Winter	Off Peak 1	404.47
2029	Winter	Off Peak 2	338.03

Energy output 36: Seasonal average lighting energy consumption in GWh for 2029

Year	Season	Time-period	Energy consumption
2029	Spring	Evening Peak	63.11
2029	Spring	Morning Peak	30.11
2029	Spring	Off Peak 1	31.36
2029	Spring	Off Peak 2	24.63
2029	Summer	Evening Peak	32.89
2029	Summer	Morning Peak	22.92
2029	Summer	Off Peak 1	28.77
2029	Summer	Off Peak 2	20.80
2029	Autumn	Evening Peak	69.94
2029	Autumn	Morning Peak	32.38
2029	Autumn	Off Peak 1	31.34
2029	Autumn	Off Peak 2	22.53
2029	Winter	Evening Peak	99.92
2029	Winter	Morning Peak	43.94
2029	Winter	Off Peak 1	36.40
2029	Winter	Off Peak 2	30.42

Appendix 3: Economic Value Tables

Economic output 1: Spot market price calculation

Appliance	*Scenario*	*Cost in million $*	*Savings in million $*	*Savings in %*
HP	Baseline	$ 53.38	-	-
HP	Load curtailment to zero	$ 20.23	$ 33.15	62%
HP	Load curtailment 0.5	$ 36.80	$ 16.57	31%
HP	Load shifting	$ 50.00	$ 3.38	6%
HW	Baseline	$ 248.73	-	-
HW	Load curtailment to zero	$ 107.16	$ 141.57	43%
HW	Load curtailment 0.5	$ 178.32	$ 70.41	28%
HW	Load shifting	$ 229.04	$ 19.69	8%
REF	Baseline	$ 136.56	-	-
REF	Load curtailment to zero	$ 80.35	$ 56.20	41%
REF	Load curtailment 0.5	$ 108.46	$ 28.10	21%
REF	Load shifting	$ 129.47	$ 7.09	5%
HP & HW	Baseline	$ 301.36	-	-
HP & HW	Load curtailment to zero	$ 127.39	$ 174.98	57%
HP & HW	Load curtailment 0.5	$ 214.88	$ 87.49	28%
HP & HW	Load shifting	$ 279.59	$ 22.78	8%
HP & HW & REF	Baseline	$ 437.92	-	-
HP & HW & REF	Load curtailment to zero	$ 207.74	$ 230.18	52%
HP & HW & REF	Load curtailment 0.5	$ 322.33	$ 115.59	26%
HP & HW & REF	Load shifting	$ 414.06	$ 23.86	5%

Economic output 2: CPD charges per year SC1

Appliance	$\overline{D}_{CP}$ *in kW*	*Price scenario in* $\$/\overline{D}_{CP}kW$	*Cost in \$ per household*	*Cost in million \$ total*
HP	0.05	PS1: \$ 112.38	\$ 5.90	\$ 3.04
HP	0.05	PS2: \$ 123.63	\$ 6.49	\$ 3.34
HP	0.05	PS3: \$ 131.98	\$ 6.92	\$ 3.57
HP	0.05	PS4: \$ 171.48	\$ 9.00	\$ 4.63
HW	0.15	PS1: \$ 112.38	\$ 16.93	\$ 23.72
HW	0.15	PS2: \$ 123.63	\$ 18.52	\$ 25.90
HW	0.15	PS3: \$ 131.98	\$ 19.71	\$ 27.51
HW	0.15	PS4: \$ 171.48	\$ 25.30	\$ 35.15
REF	0.06	PS1: \$ 112.38	\$ 6.87	\$ 10.01
REF	0.06	PS2: \$ 123.63	\$ 7.55	\$ 11.01
REF	0.06	PS3: \$ 131.98	\$ 8.06	\$ 11.75
REF	0.06	PS4: \$ 171.48	\$ 10.45	\$ 15.27
HP & HW	0.19	PS1: \$ 112.38	\$ 22.83	\$ 26.76
HP & HW	0.19	PS2: \$ 123.63	\$ 25.01	\$ 29.24
HP & HW	0.19	PS3: \$ 131.98	\$ 26.63	\$ 31.08
HP & HW	0.19	PS4: \$ 171.48	\$ 34.30	\$ 39.78
HP & HW & REF	0.26	PS1: \$ 112.38	\$ 29.69	\$ 36.77
HP & HW & REF	0.26	PS2: \$ 123.63	\$ 32.56	\$ 40.25
HP & HW & REF	0.26	PS3: \$ 131.98	\$ 34.70	\$ 42.83
HP & HW & REF	0.26	PS4: \$ 171.48	\$ 44.78	\$ 55.05

Economic output 3: CPD charges per year SC2

Appliance	$\overline{D}_{CP}$ *in kW*	*Price scenario in \$/*$\overline{D}_{CP}$*kW*	*Cost in \$ per household*	*Cost in million \$ total*
HP	0.15	PS1: \$ 112.38	\$ 17.37	\$ 8.94
HP	0.15	PS2: \$ 123.63	\$ 19.10	\$ 9.84
HP	0.15	PS3: \$ 131.98	\$ 20.40	\$ 10.50
HP	0.15	PS4: \$ 171.48	\$ 26.50	\$ 13.65
HW	0.30	PS1: \$ 112.38	\$ 33.06	\$ 45.73
HW	0.30	PS2: \$ 123.63	\$ 36.27	\$ 50.11
HW	0.30	PS3: \$ 131.98	\$ 38.66	\$ 53.36
HW	0.30	PS4: \$ 171.48	\$ 50.93	\$ 68.73
REF	0.11	PS1: \$ 112.38	\$ 12.69	\$ 18.49
REF	0.11	PS2: \$ 123.63	\$ 13.96	\$ 20.34
REF	0.11	PS3: \$ 131.98	\$ 14.90	\$ 21.72
REF	0.11	PS4: \$ 171.48	\$ 19.36	\$ 28.22
HP & HW	0.44	PS1: \$ 112.38	\$ 50.43	\$ 54.68
HP & HW	0.44	PS2: \$ 123.63	\$ 55.38	\$ 59.95
HP & HW	0.44	PS3: \$ 131.98	\$ 59.05	\$ 63.87
HP & HW	0.44	PS4: \$ 171.48	\$ 76.42	\$ 82.38
HP & HW & REF	0.55	PS1: \$ 112.38	\$ 63.12	\$ 73.17
HP & HW & REF	0.55	PS2: \$ 123.63	\$ 69.33	\$ 80.29
HP & HW & REF	0.55	PS3: \$ 131.98	\$ 73.95	\$ 85.58
HP & HW & REF	0.55	PS4: \$ 171.48	\$ 95.78	\$ 110.59

Economic output 4: CPD charges per year SC3

Appliance	$\overline{D}_{CP}$ *in kW*	*Price scenario in* $\$/\overline{D}_{CP}kW$	*Cost in $ per household*	*Cost in million $ total*
HP	0.17	PS1: $ 112.38	$ 18.70	$ 9.63
HP	0.17	PS2: $ 123.63	$ 20.58	$ 10.60
HP	0.17	PS3: $ 131.98	$ 21.97	$ 11.31
HP	0.17	PS4: $ 171.48	$ 28.54	$ 14.70
HW	0.26	PS1: $ 112.38	$ 29.36	$ 40.68
HW	0.26	PS2: $ 123.63	$ 32.19	$ 44.55
HW	0.26	PS3: $ 131.98	$ 34.30	$ 47.42
HW	0.26	PS4: $ 171.48	$ 44.27	$ 61.01
REF	0.10	PS1: $ 112.38	$ 11.60	$ 16.91
REF	0.10	PS2: $ 123.63	$ 12.76	$ 18.60
REF	0.10	PS3: $ 131.98	$ 13.63	$ 19.86
REF	0.10	PS4: $ 171.48	$ 17.70	$ 25.80
HP & HW	0.43	PS1: $ 112.38	$ 48.06	$ 50.31
HP & HW	0.43	PS2: $ 123.63	$ 52.77	$ 55.14
HP & HW	0.43	PS3: $ 131.98	$ 56.27	$ 58.74
HP & HW	0.43	PS4: $ 171.48	$ 72.81	$ 75.71
HP & HW & REF	0.52	PS1: $ 112.38	$ 59.67	$ 67.22
HP & HW & REF	0.52	PS2: $ 123.63	$ 65.53	$ 73.74
HP & HW & REF	0.52	PS3: $ 131.98	$ 69.90	$ 78.59
HP & HW & REF	0.52	PS4: $ 171.48	$ 90.51	$ 101.51

Economic output 5: CPD charges per year SC4 (Load reduction at all CPD events)

Appliance	$\bar{D}_{CP}$ *in kW*	*Price scenario in* $\$/\bar{D}_{CP}kW$	*Cost in $ per household*	*Cost in million $ total*
HP	0.26	PS1: $ 112.38	$ 28.84	$ 14.85
HP	0.26	PS2: $ 123.63	$ 31.72	$ 16.34
HP	0.26	PS3: $ 131.98	$ 33.87	$ 17.44
HP	0.26	PS4: $ 171.48	$ 44.00	$ 22.66
HW	0.45	PS1: $ 112.38	$ 50.53	$ 68.91
HW	0.45	PS2: $ 123.63	$ 55.58	$ 75.81
HW	0.45	PS3: $ 131.98	$ 59.34	$ 80.94
HW	0.45	PS4: $ 171.48	$ 77.10	$ 105.16
REF	0.16	PS1: $ 112.38	$ 18.51	$ 26.98
REF	0.16	PS2: $ 123.63	$ 20.36	$ 29.68
REF	0.16	PS3: $ 131.98	$ 21.74	$ 31.68
REF	0.16	PS4: $ 171.48	$ 28.24	$ 41.16
HP & HW	0.69	PS1: $ 112.38	$ 78.04	$ 82.59
HP & HW	0.69	PS2: $ 123.63	$ 86.75	$ 90.66
HP & HW	0.69	PS3: $ 131.98	$ 92.48	$ 96.65
HP & HW	0.69	PS4: $ 171.48	$ 121.55	$ 125.97
HP & HW & REF	0.85	PS1: $ 112.38	$ 96.55	$ 108.57
HP & HW & REF	0.85	PS2: $ 123.63	$ 106.11	$ 119.33
HP & HW & REF	0.85	PS3: $ 131.98	$ 113.21	$ 127.33
HP & HW & REF	0.85	PS4: $ 171.48	$ 146.55	$ 165.13

Economic output 6: EE spot market price analysis by year

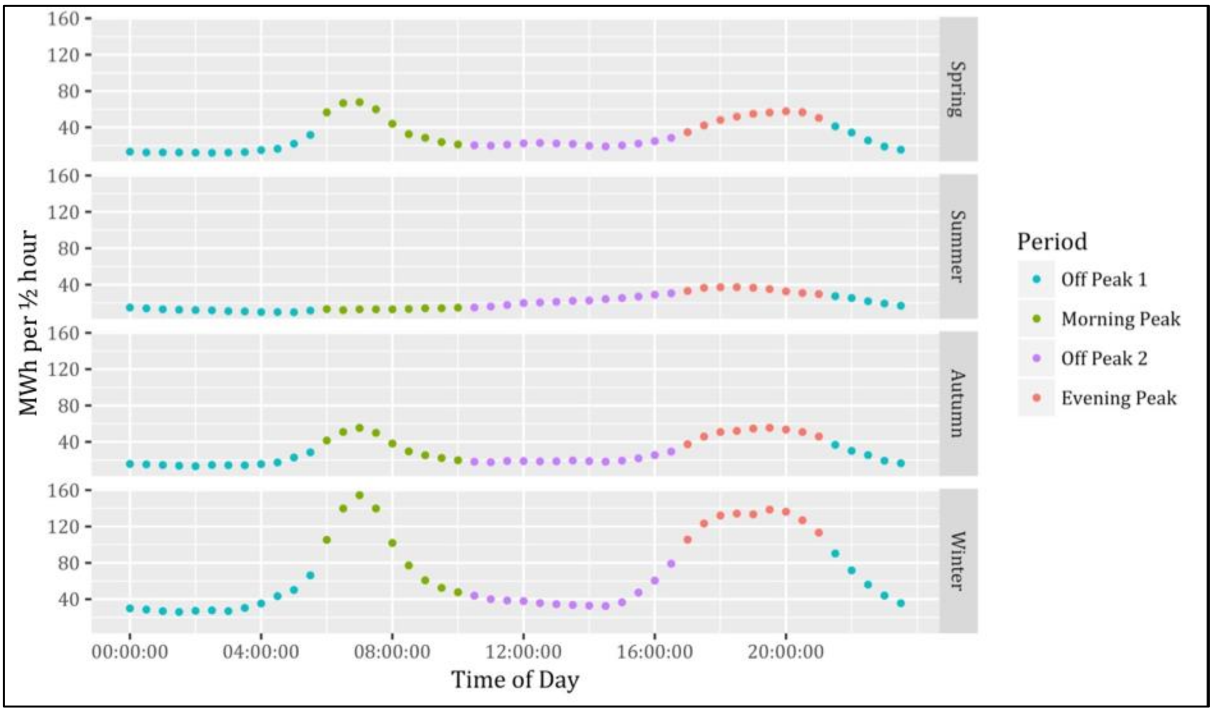
Appliance	*Year*	*Cost in million $*	*Cost per household in $*	*Savings in million $ (compared to 2015)*	*Savings in % (compared to 2015)*
Lighting	2015	$ 120.00	$ 66.80	-	-
Lighting	2017	$ 114.22	$ 62.30	$ 5.78	5%
Lighting	2019	$ 104.00	$ 55.66	$ 16.00	13%
Lighting	2021	$ 91.00	$ 47.80	$ 29.00	24%
Lighting	2023	$ 78.10	$ 40.34	$ 41.90	35%
Lighting	2025	$ 66.28	$ 33.68	$ 53.72	45%
Lighting	2027	$ 55.89	$ 27.97	$ 64.11	53%
Lighting	2029	$ 47.30	$ 23.34	$ 72.70	61%

Economic output 7: CPD charges for EE (no DR applied) by year

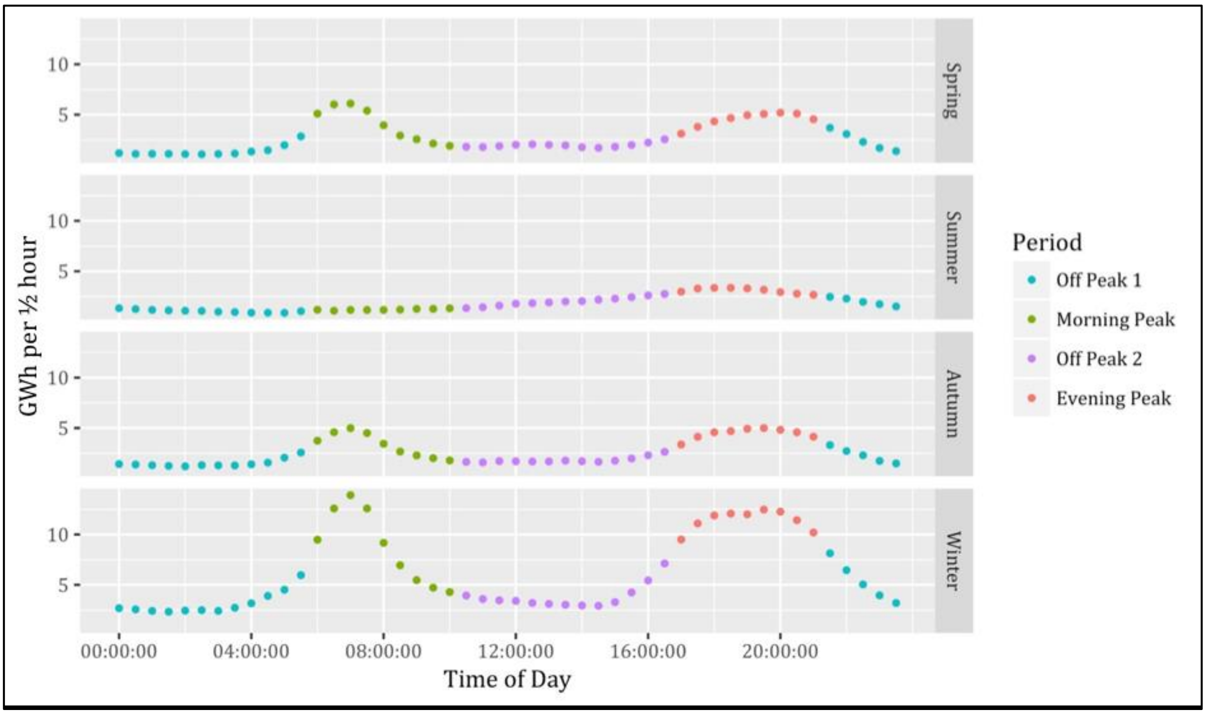
Appliance	*Year*	*DCP* in kW	*Price scenario in $/DCP*kW	*Cost per household in $*	*Cost in million $*
Lighting	2015	0.15	PS1: $ 112.38	$ 17.15	$ 30.81
Lighting	2015	0.15	PS2: $ 123.63	$ 18.87	$ 33.89
Lighting	2015	0.15	PS3: $ 131.98	$ 20.14	$ 36.18
Lighting	2015	0.15	PS4: $ 171.48	$ 26.17	$ 47.01
Lighting	2017	0.14	PS1: $ 112.38	$ 15.99	$ 29.32
Lighting	2017	0.14	PS2: $ 123.63	$ 17.59	$ 32.25
Lighting	2017	0.14	PS3: $ 131.98	$ 18.78	$ 34.43
Lighting	2017	0.14	PS4: $ 171.48	$ 24.40	$ 44.73
Lighting	2019	0.13	PS1: $ 112.38	$ 14.29	$ 26.69
Lighting	2019	0.13	PS2: $ 123.63	$ 15.71	$ 29.36
Lighting	2019	0.13	PS3: $ 131.98	$ 16.78	$ 31.35
Lighting	2019	0.13	PS4: $ 171.48	$ 21.80	$ 40.73
Lighting	2021	0.11	PS1: $ 112.38	$ 12.28	$ 23.38
Lighting	2021	0.11	PS2: $ 123.63	$ 13.51	$ 25.72
Lighting	2021	0.11	PS3: $ 131.98	$ 14.42	$ 27.45
Lighting	2021	0.11	PS4: $ 171.48	$ 18.74	$ 35.67
Lighting	2023	0.09	PS1: $ 112.38	$ 10.35	$ 20.04

Lighting	2023	0.09	PS2: $ 123.63	$ 11.39	$ 22.05
Lighting	2023	0.09	PS3: $ 131.98	$ 12.16	$ 23.54
Lighting	2023	0.09	PS4: $ 171.48	$ 15.80	$ 30.58
Lighting	2025	0.08	PS1: $ 112.38	$ 8.64	$ 17.01
Lighting	2025	0.08	PS2: $ 123.63	$ 9.51	$ 18.71
Lighting	2025	0.08	PS3: $ 131.98	$ 10.15	$ 19.98
Lighting	2025	0.08	PS4: $ 171.48	$ 13.19	$ 25.96
Lighting	2027	0.06	PS1: $ 112.38	$ 7.18	$ 14.35
Lighting	2027	0.06	PS2: $ 123.63	$ 7.90	$ 15.78
Lighting	2027	0.06	PS3: $ 131.98	$ 8.43	$ 16.85
Lighting	2027	0.06	PS4: $ 171.48	$ 10.95	$ 21.89
Lighting	2029	0.05	PS1: $ 112.38	$ 5.99	$ 12.14
Lighting	2029	0.05	PS2: $ 123.63	$ 6.59	$ 13.36
Lighting	2029	0.05	PS3: $ 131.98	$ 7.04	$ 14.26
Lighting	2029	0.05	PS4: $ 171.48	$ 9.14	$ 18.53

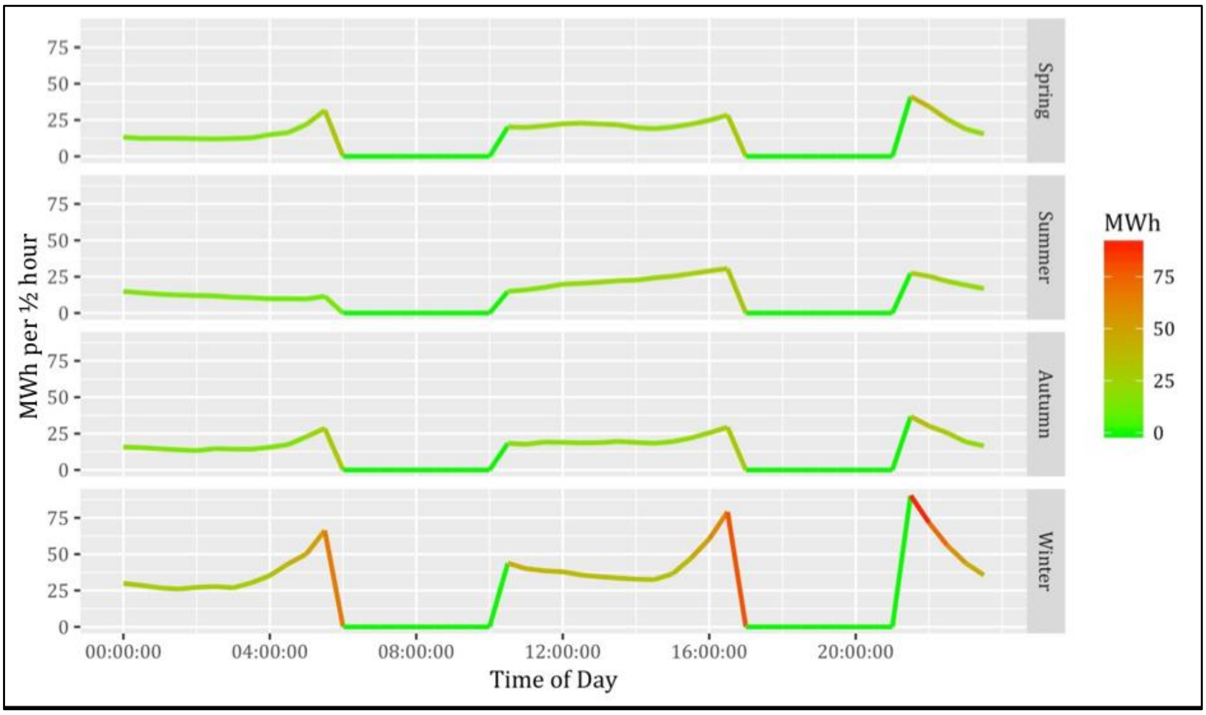
Appendix 4: Further Visualisation of DR Scenarios



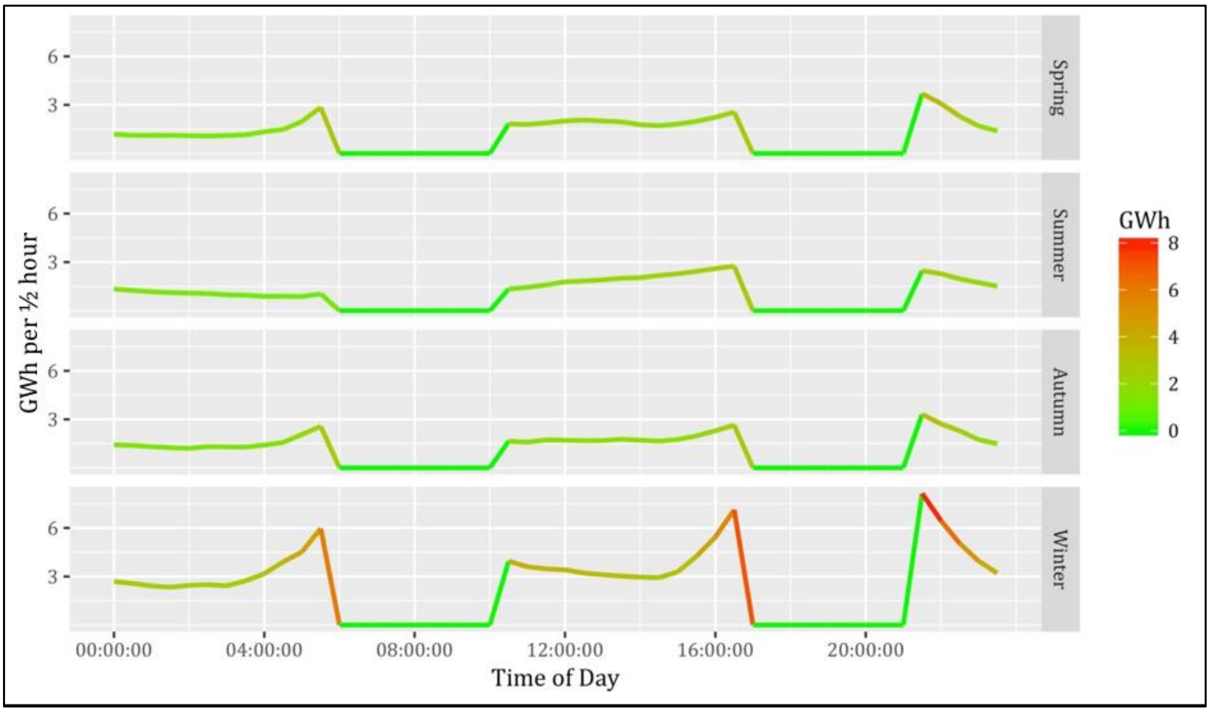
Graphic 1| HP total New Zealand energy consumption per day in MWh



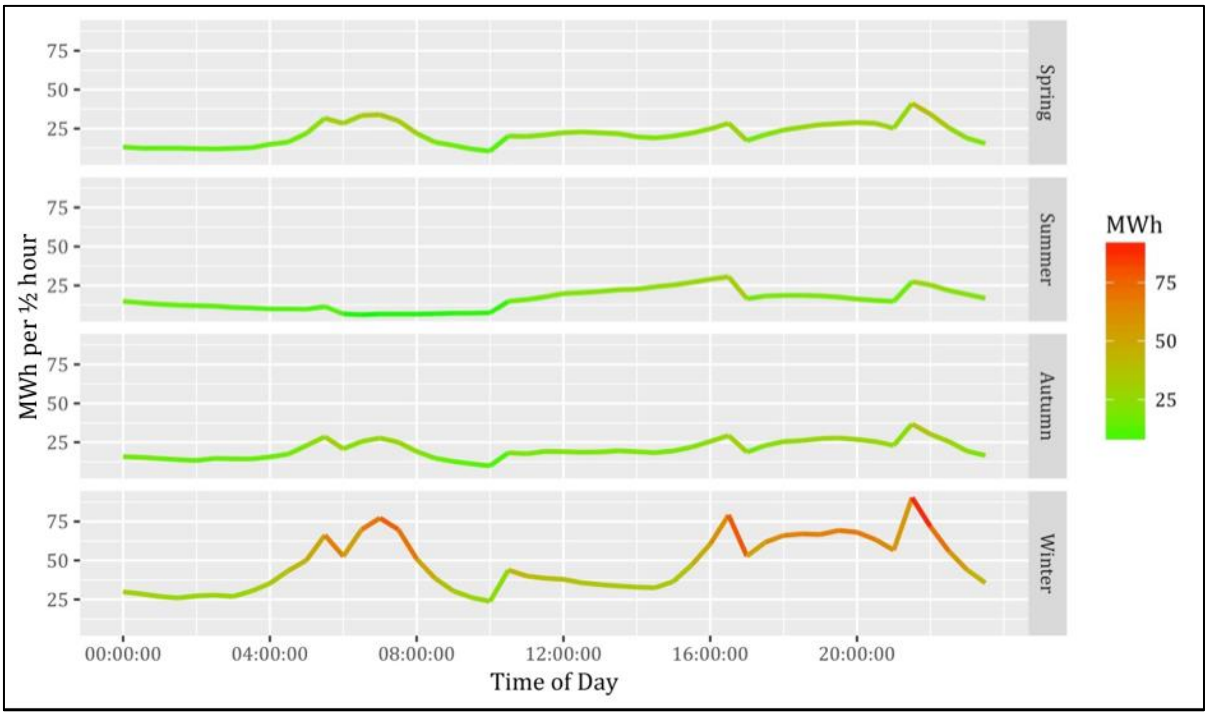
Graphic 2| HP total New Zealand energy consumption per season in GWh



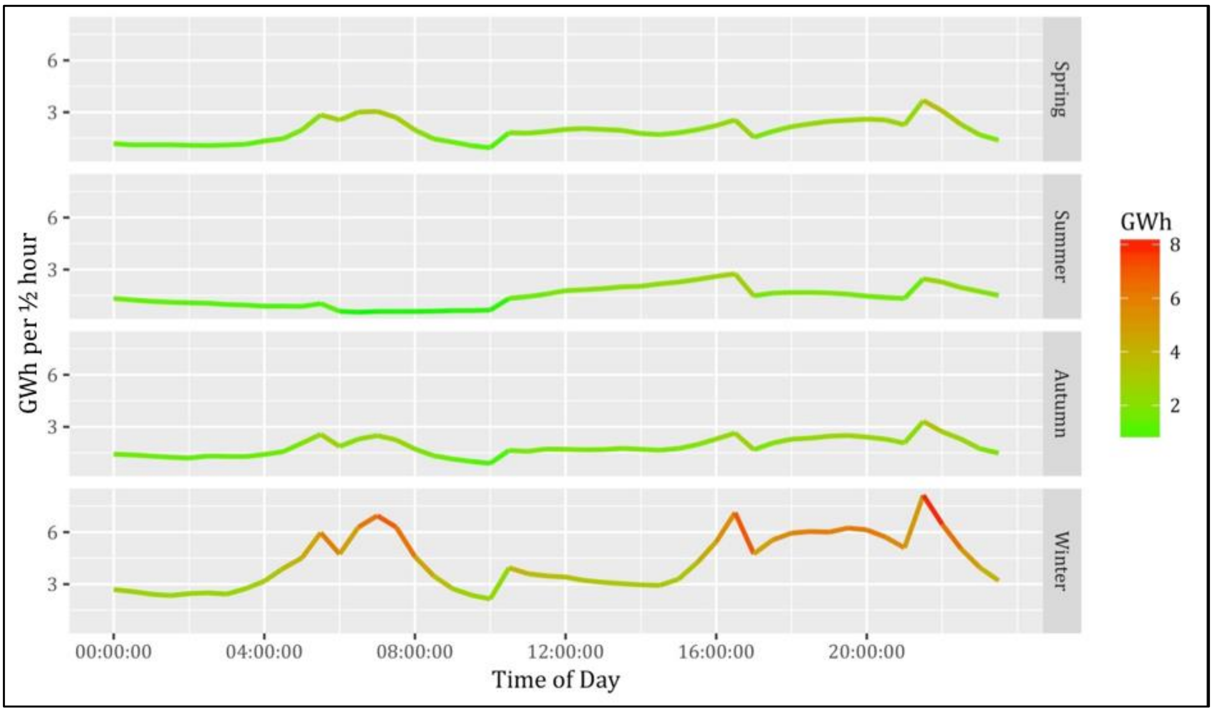
Graphic 3| HP SC1 total New Zealand energy consumption per day in MWh



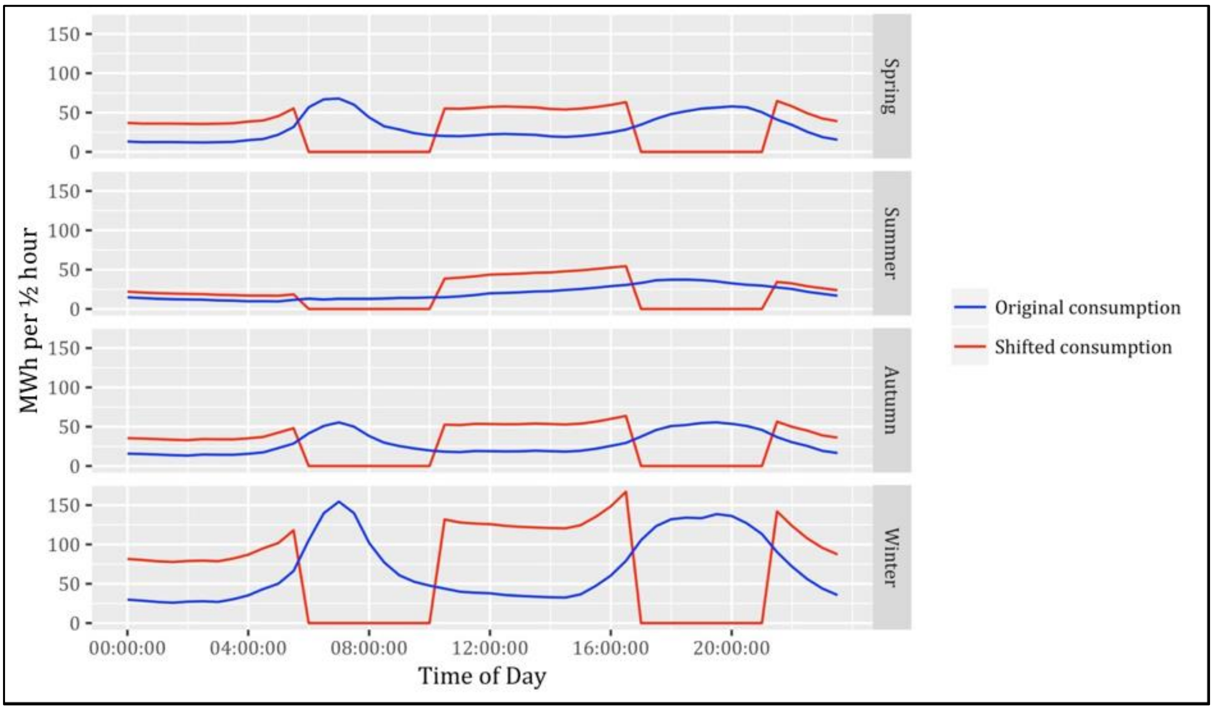
Graphic 4| HP SC1 total New Zealand energy consumption per season in GWh



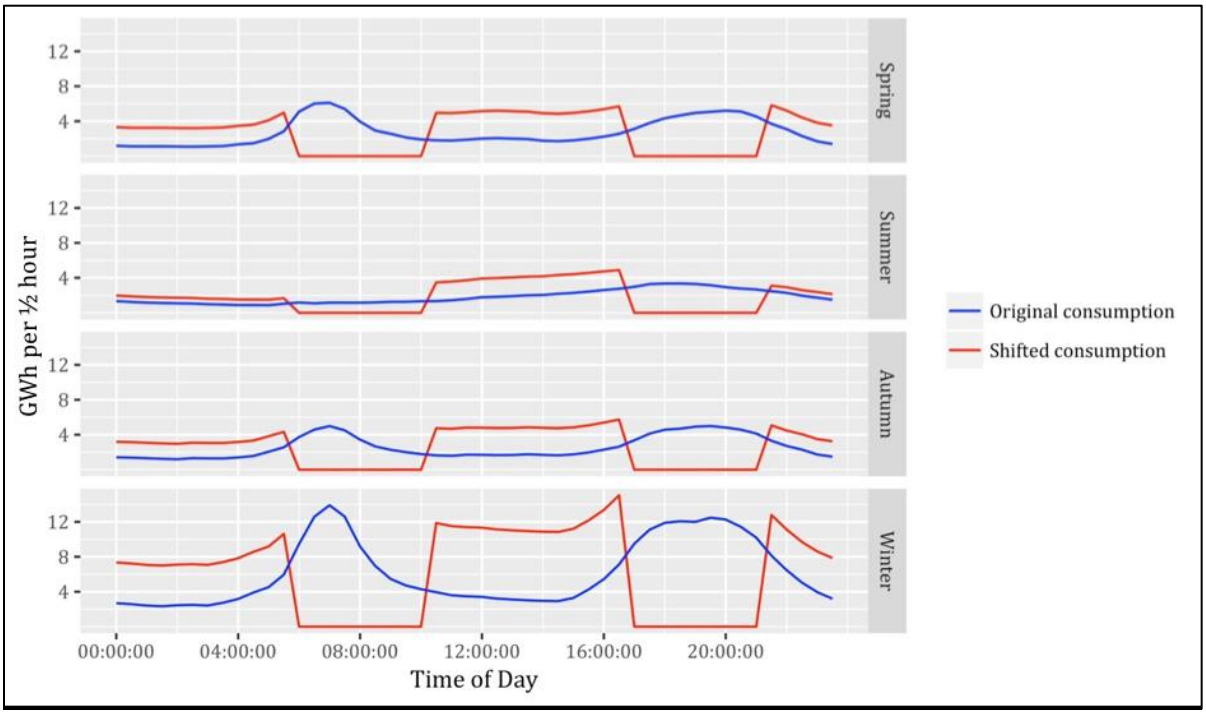
Graphic 5| HP SC2 total New Zealand energy consumption per day in MWh



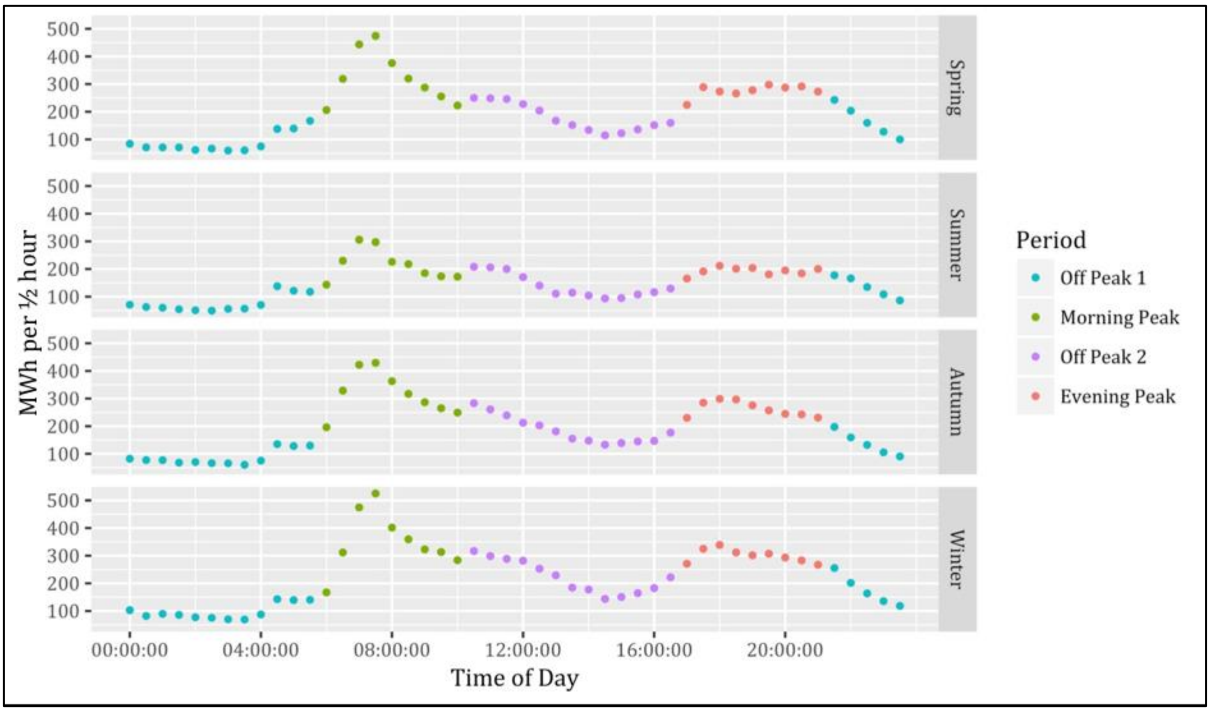
Graphic 6| HP SC2 total New Zealand energy consumption per season in GWh



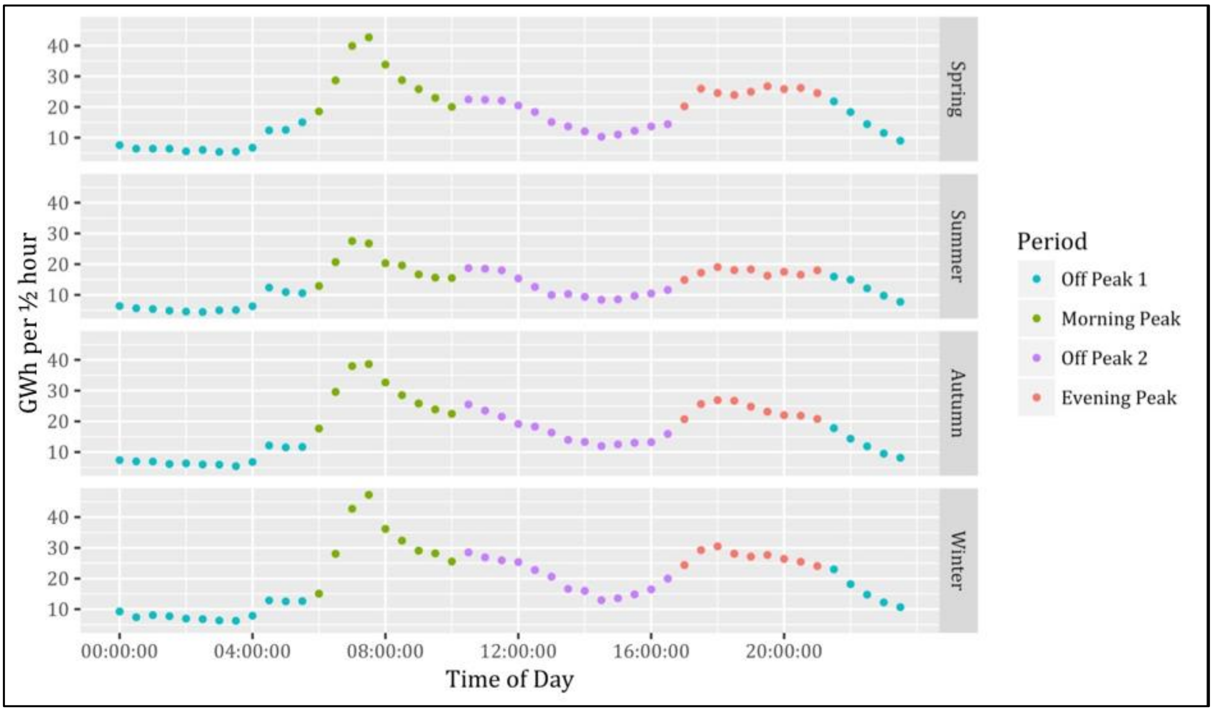
Graphic 7| HP SC3 total energy consumption New Zealand per day in MWh



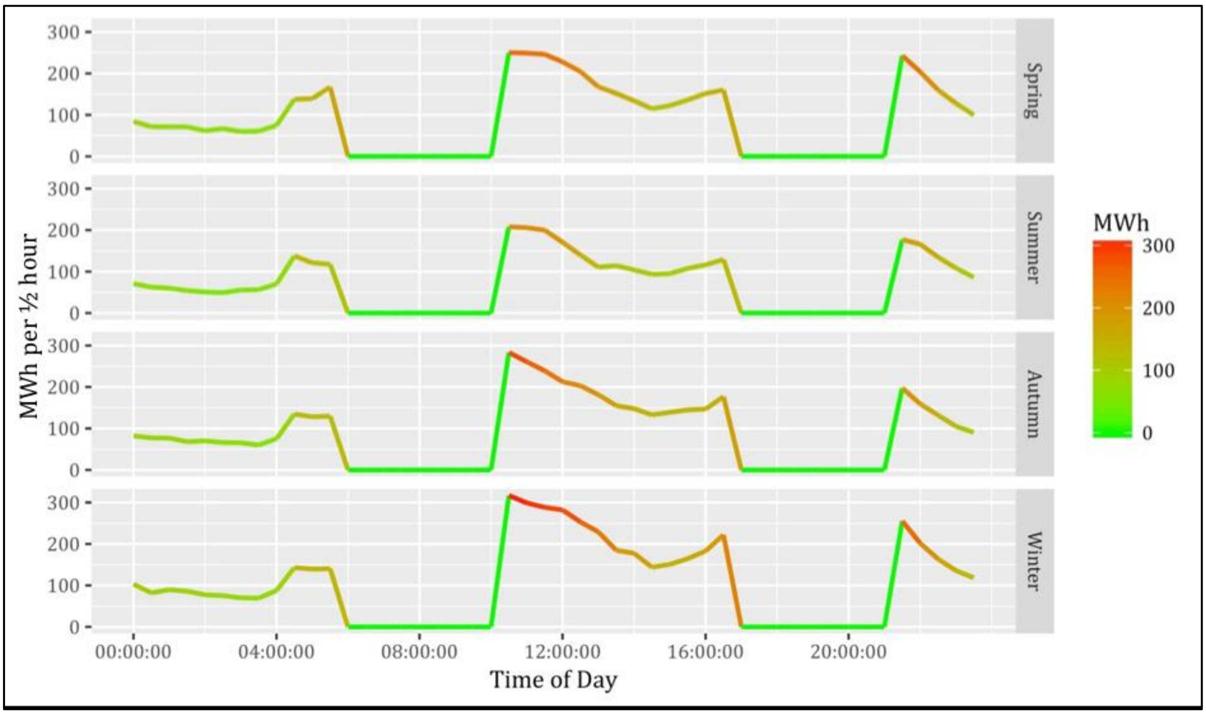
Graphic 8| HP SC3 total energy consumption New Zealand per season in GWh



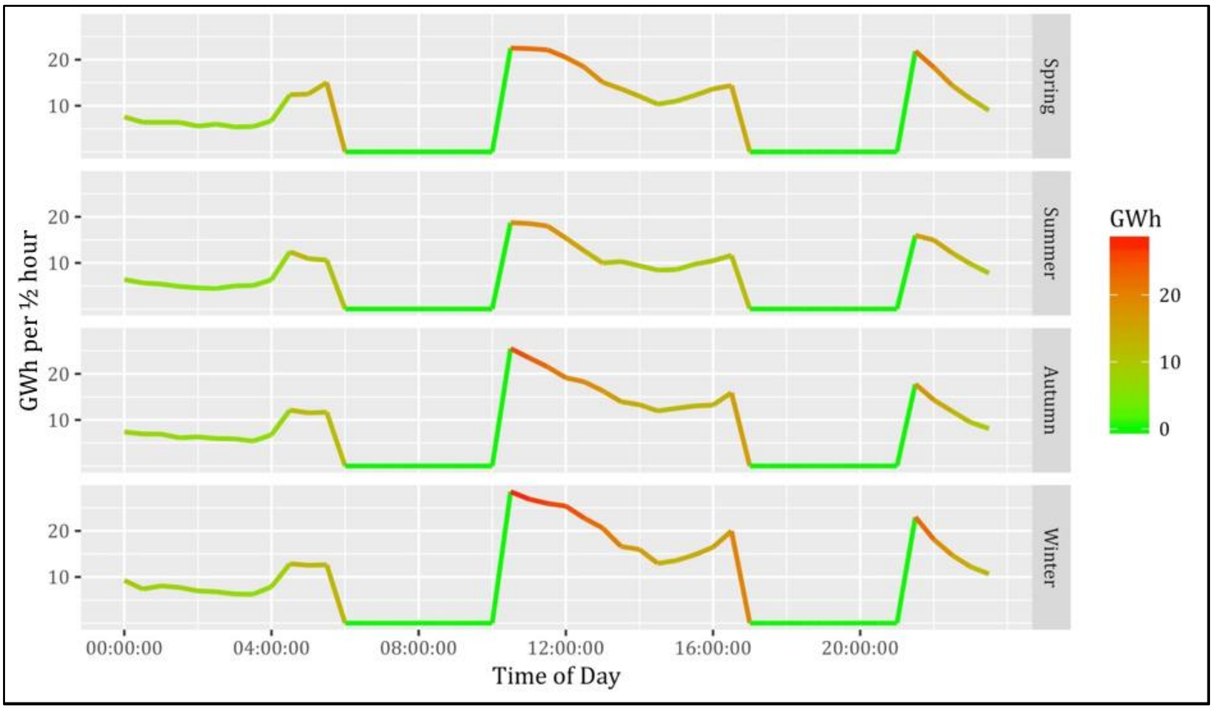
Graphic 9| HW total energy consumption New Zealand per day in MWh



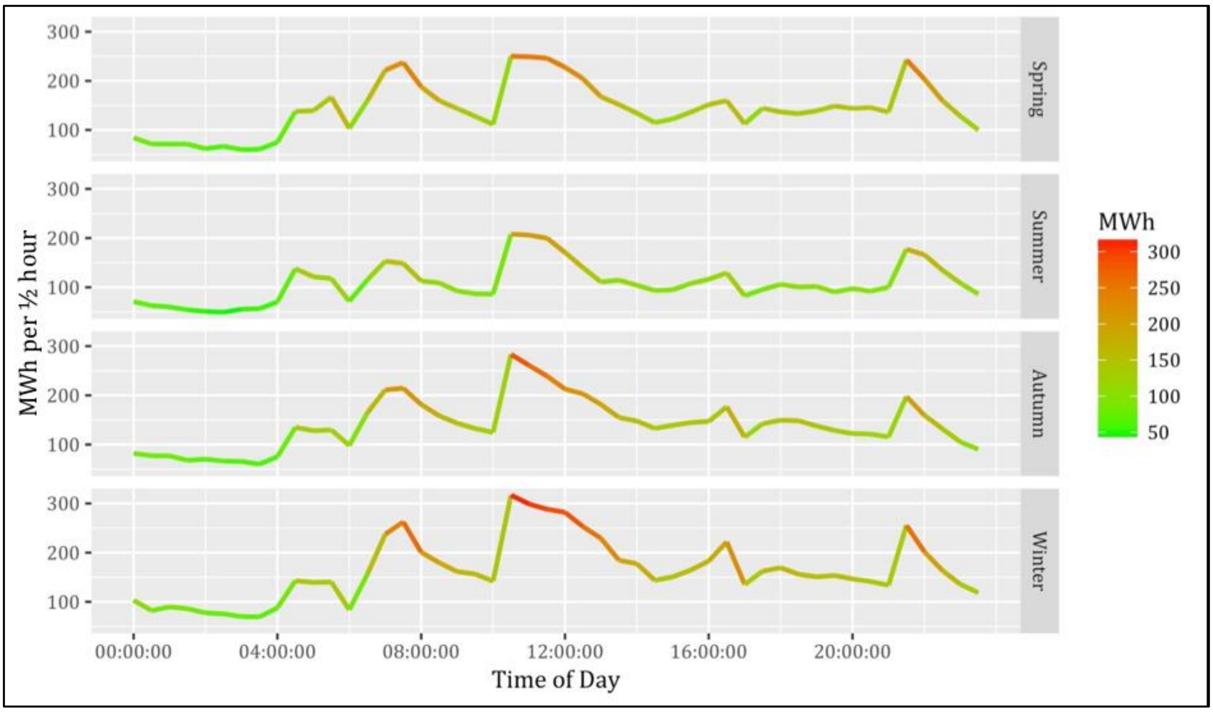
Graphic 10| HW total energy consumption New Zealand per season in GWh



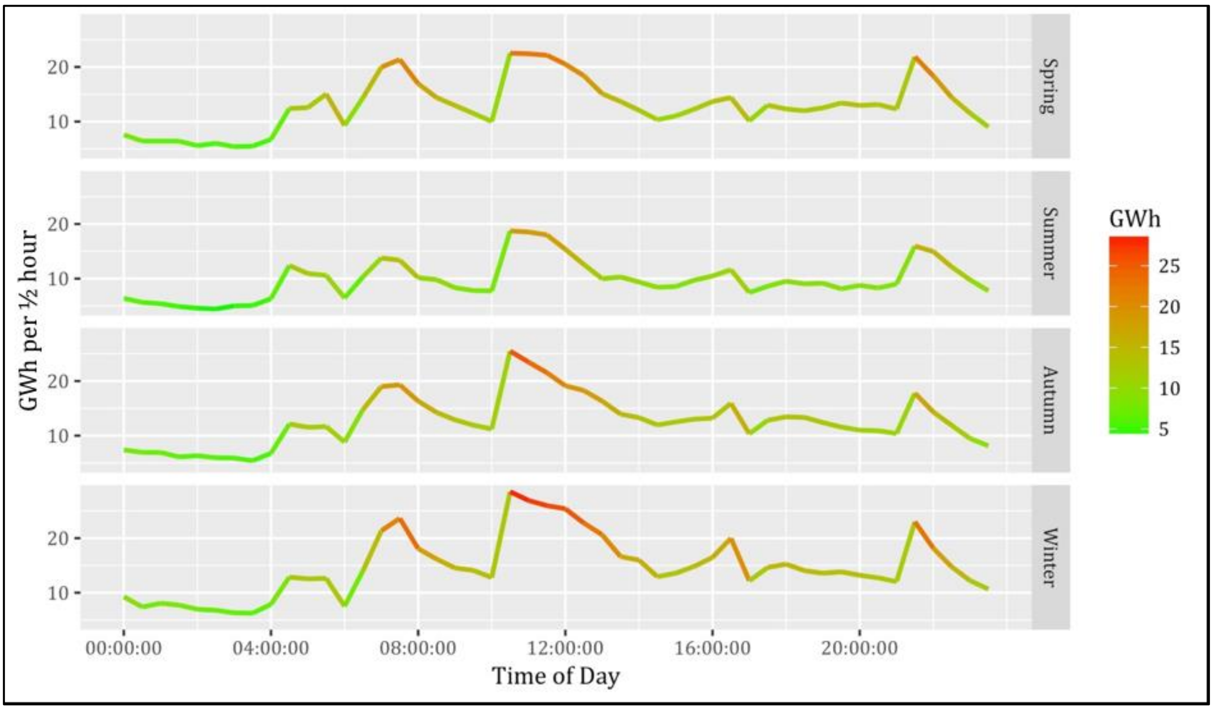
Graphic 11| HW SC1 total energy consumption New Zealand per day in MWh



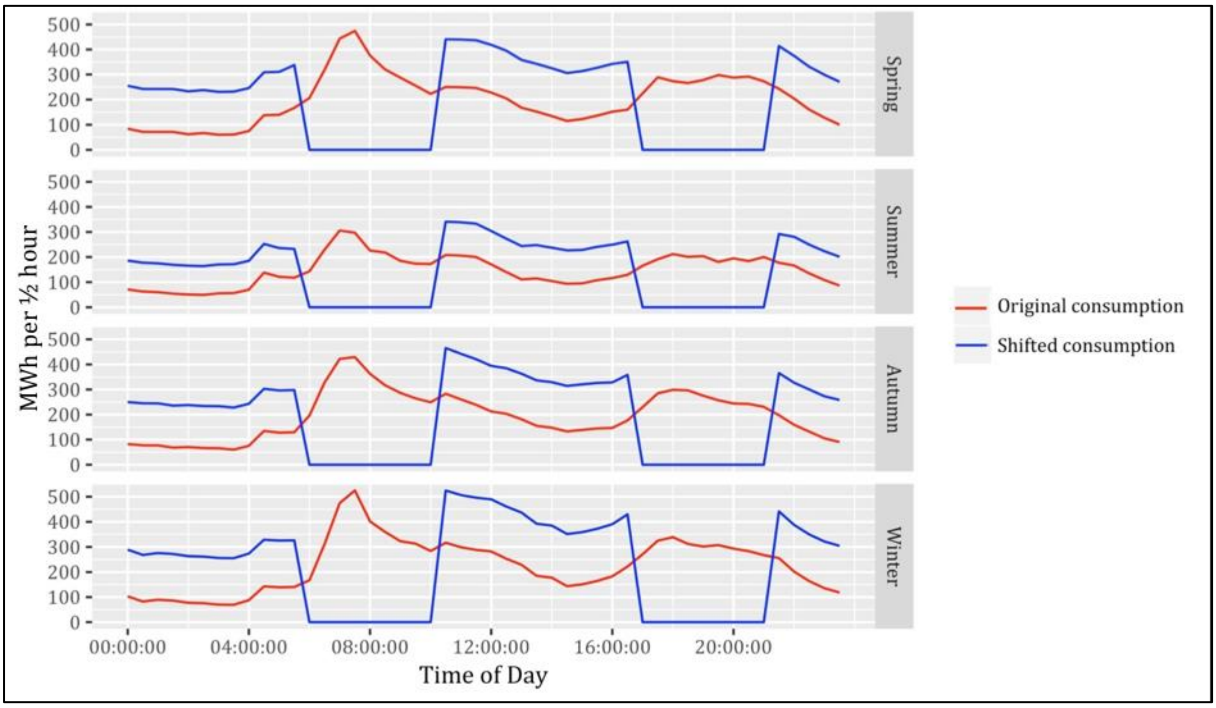
Graphic 12| HW SC1 total energy consumption New Zealand per season in GWh



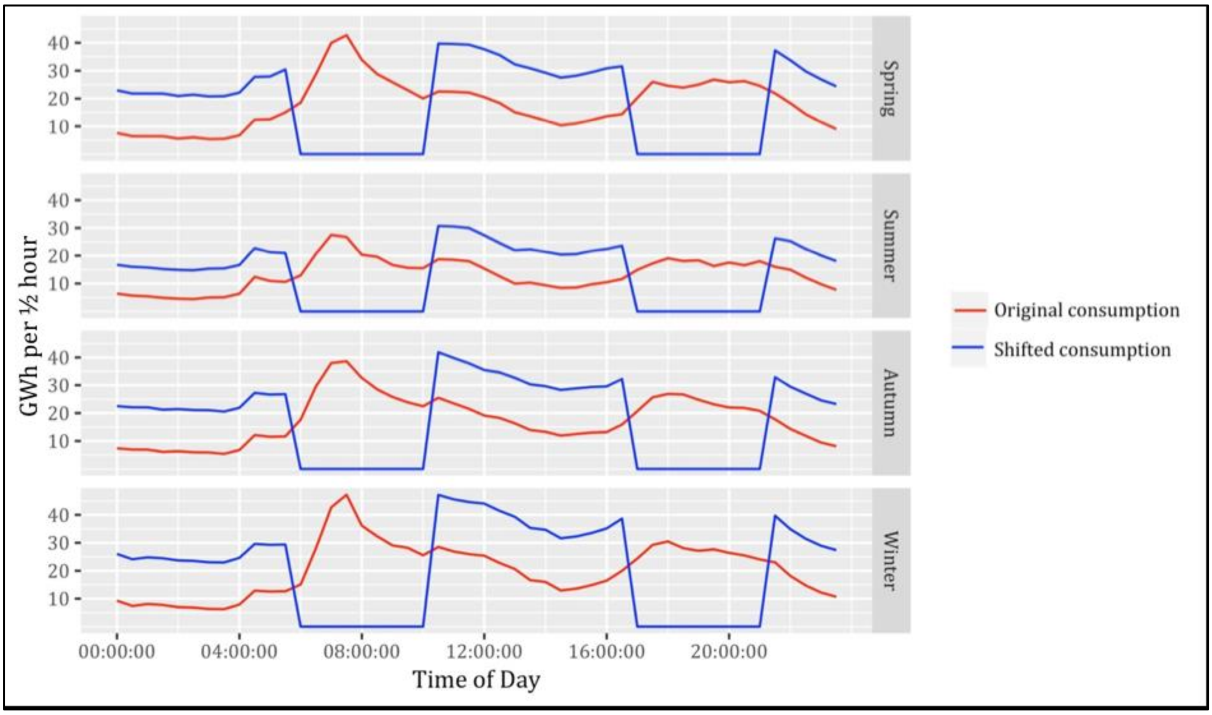
Graphic 13| HW SC2 total energy consumption New Zealand per day in MWh



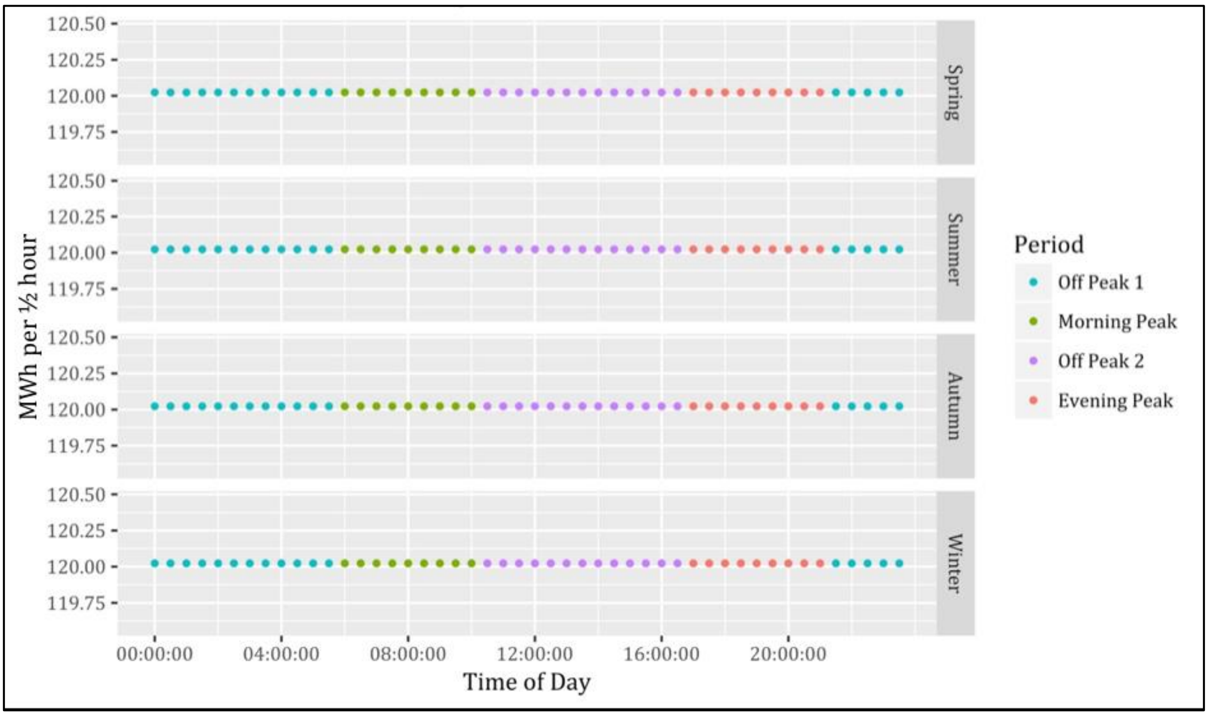
Graphic 14| HW SC2 total energy consumption New Zealand per season in GWh



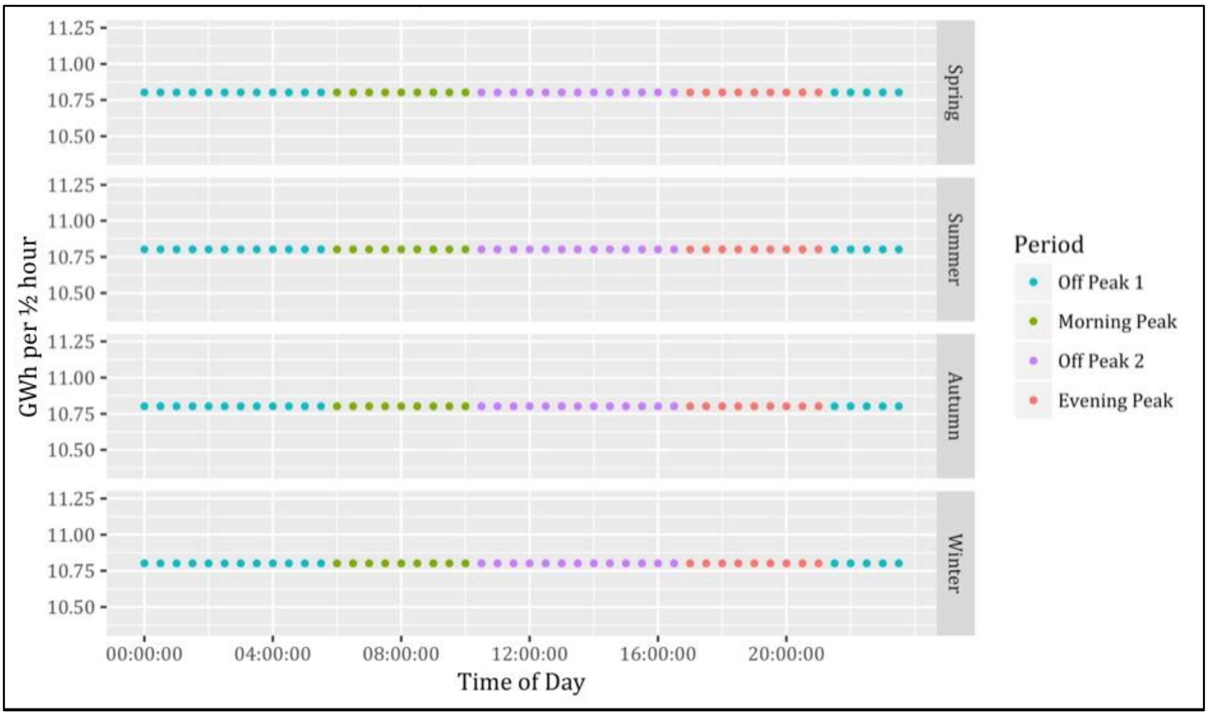
Graphic 15| HW SC3 total energy consumption New Zealand per day in MWh



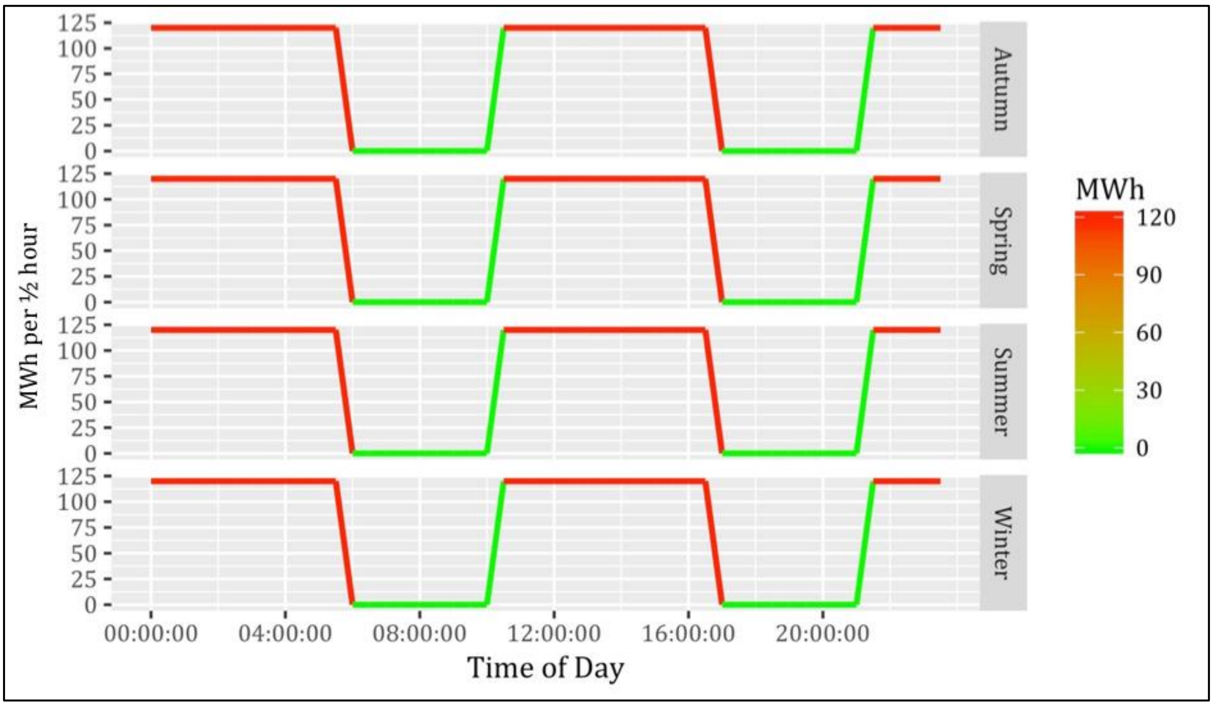
Graphic 16| HW SC3 total energy consumption New Zealand per season in GWh



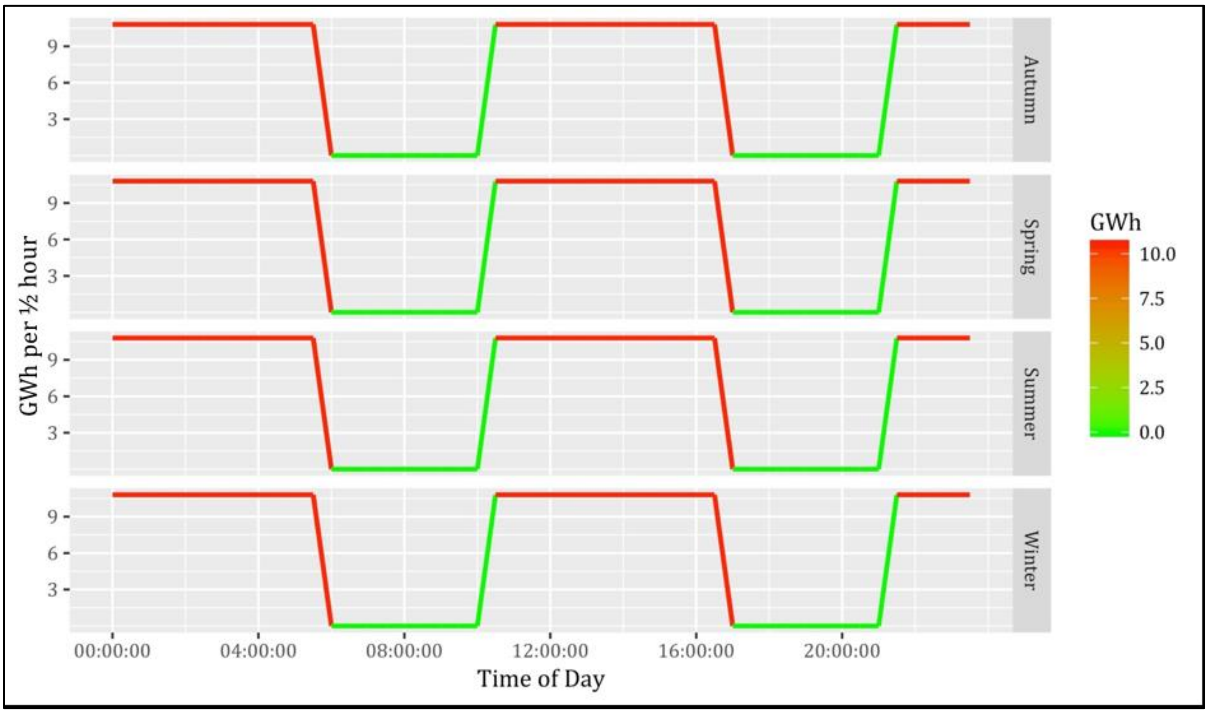
Graphic 17| REF total energy consumption New Zealand per day in MW



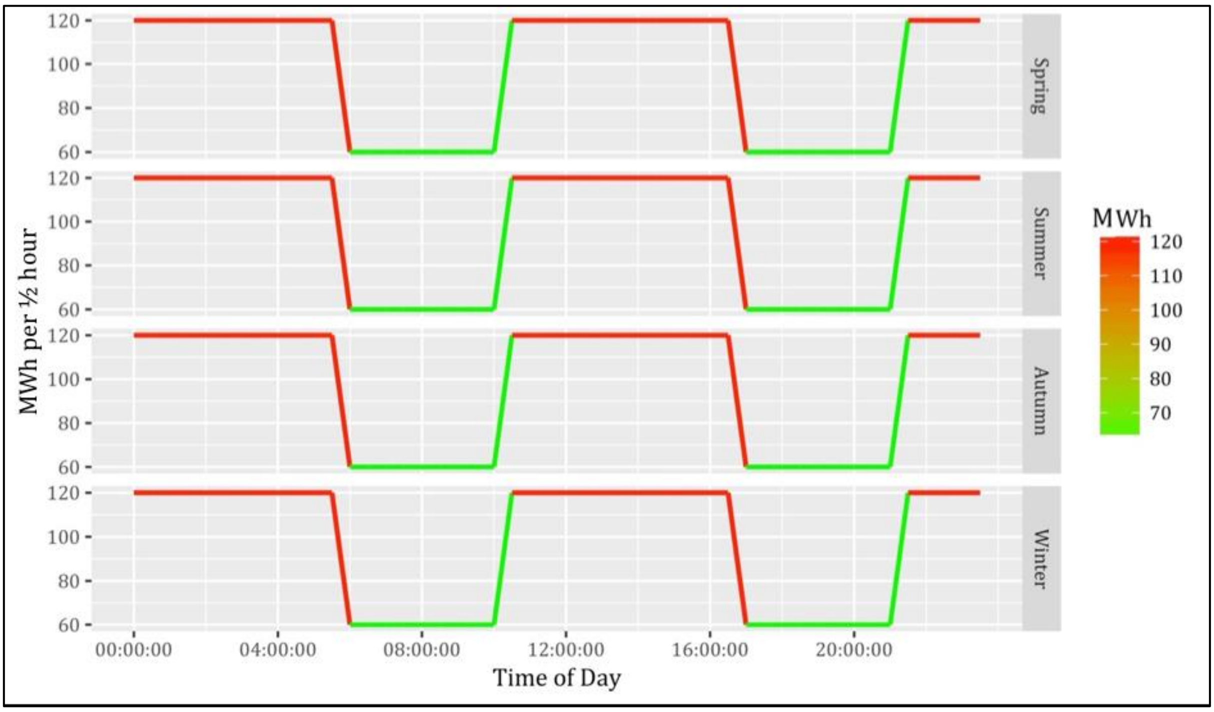
Graphic 18| REF total energy consumption New Zealand per season in GWh



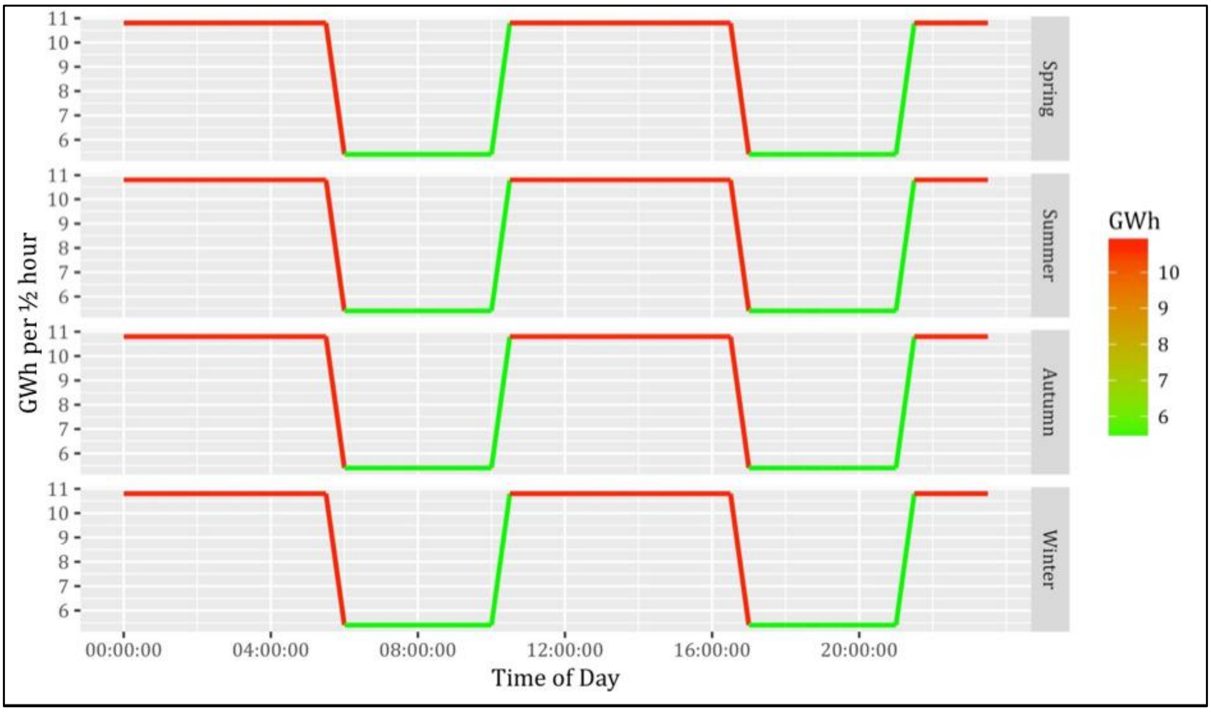
Graphic 19| REF SC1 total energy consumption New Zealand per day in MWh



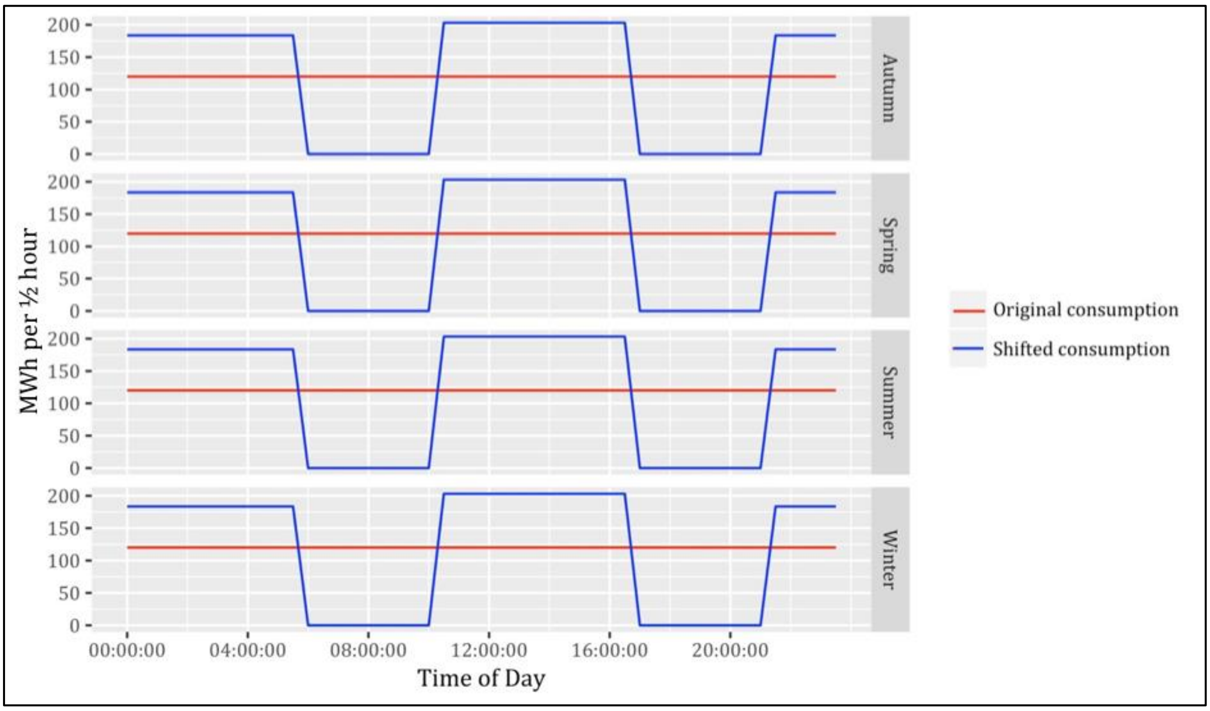
Graphic 20| REF SC1 total energy consumption New Zealand per season in GWh



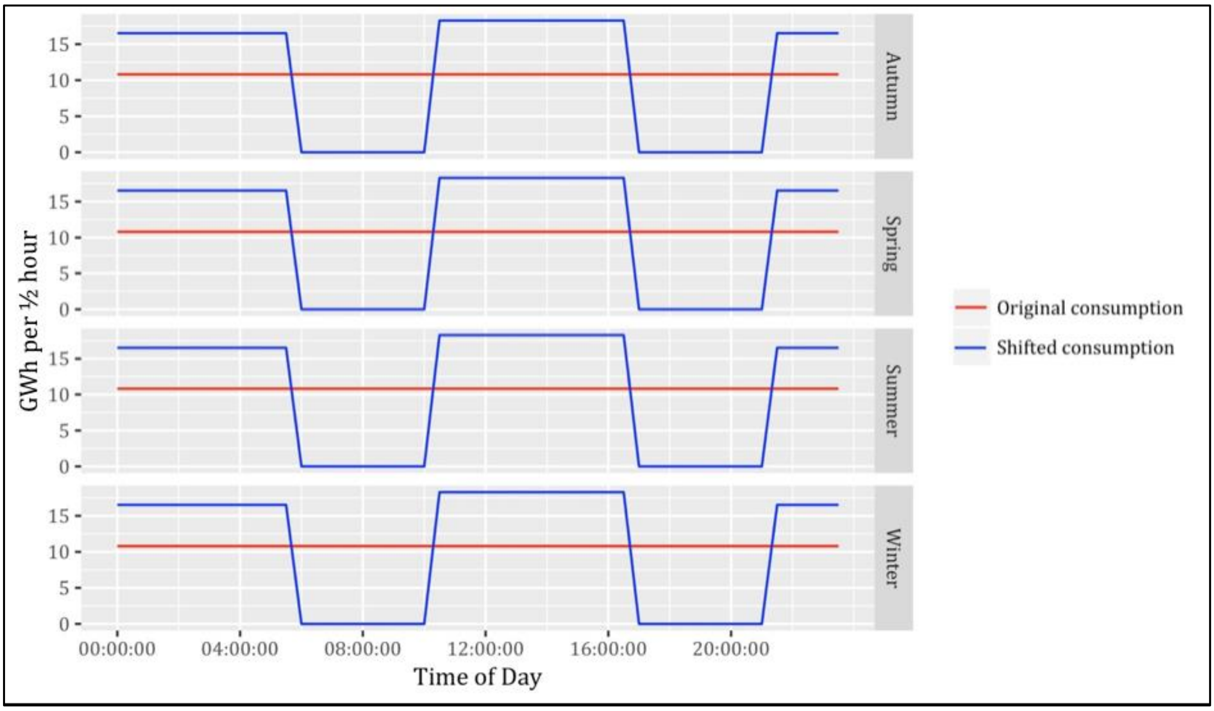
Graphic 21| REF SC2 total energy consumption New Zealand per day in MWh



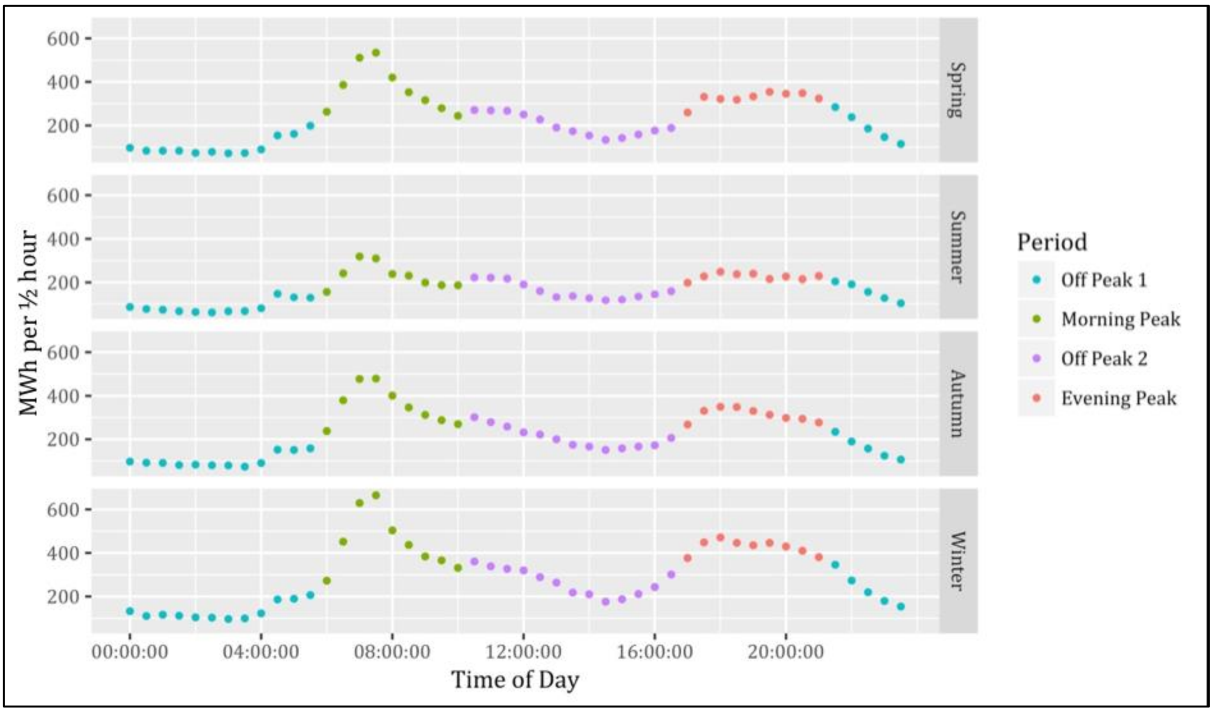
Graphic 22| REF SC2 total energy consumption New Zealand per season in GWh



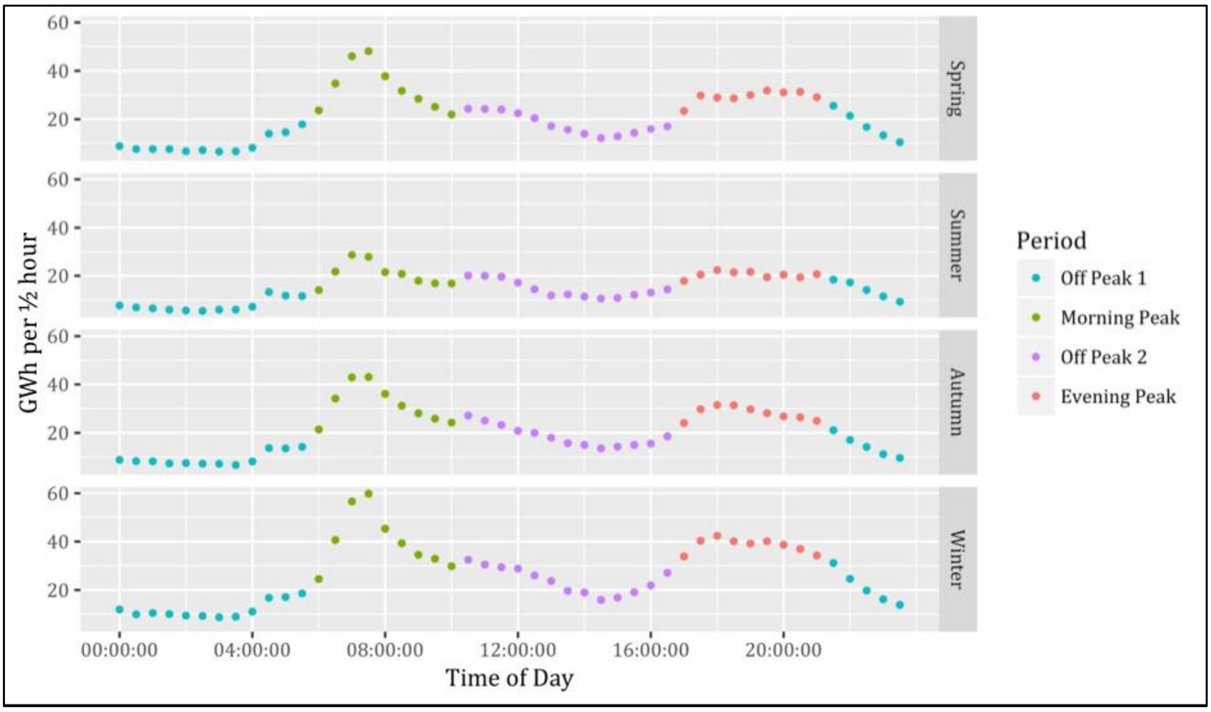
Graphic 23| REF SC3 total energy consumption New Zealand per day in MWh



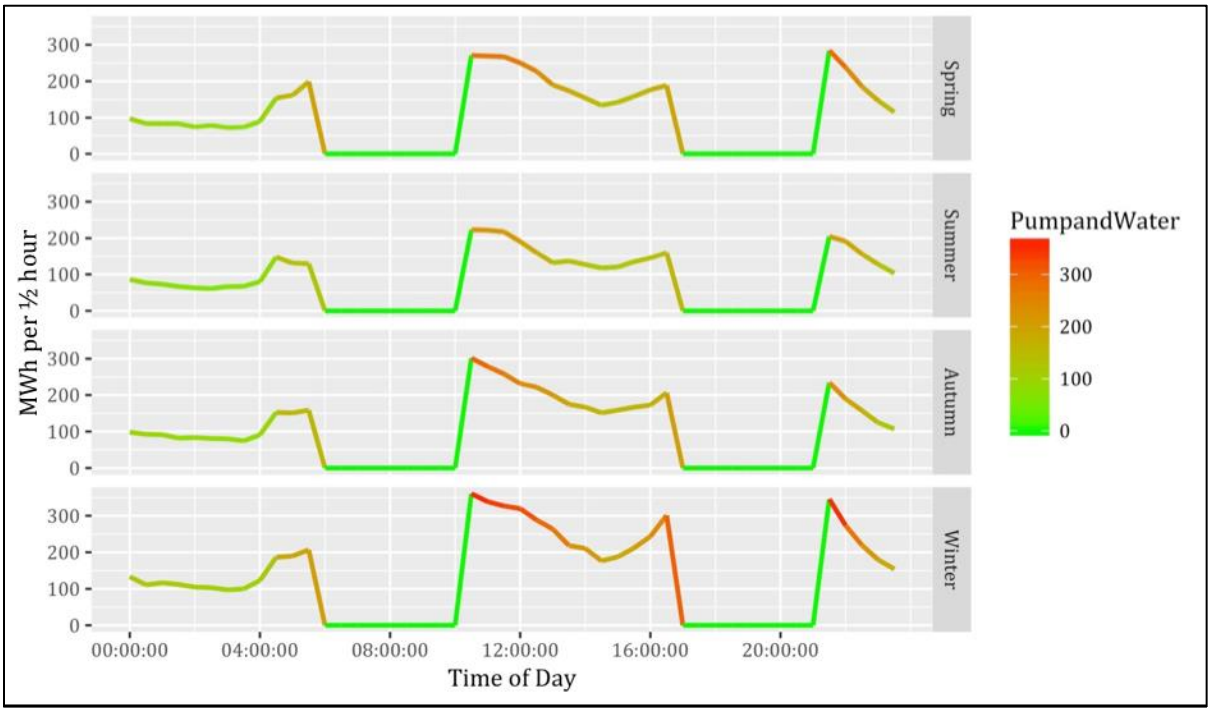
Graphic 24| REF SC3 total energy consumption New Zealand per season in GWh



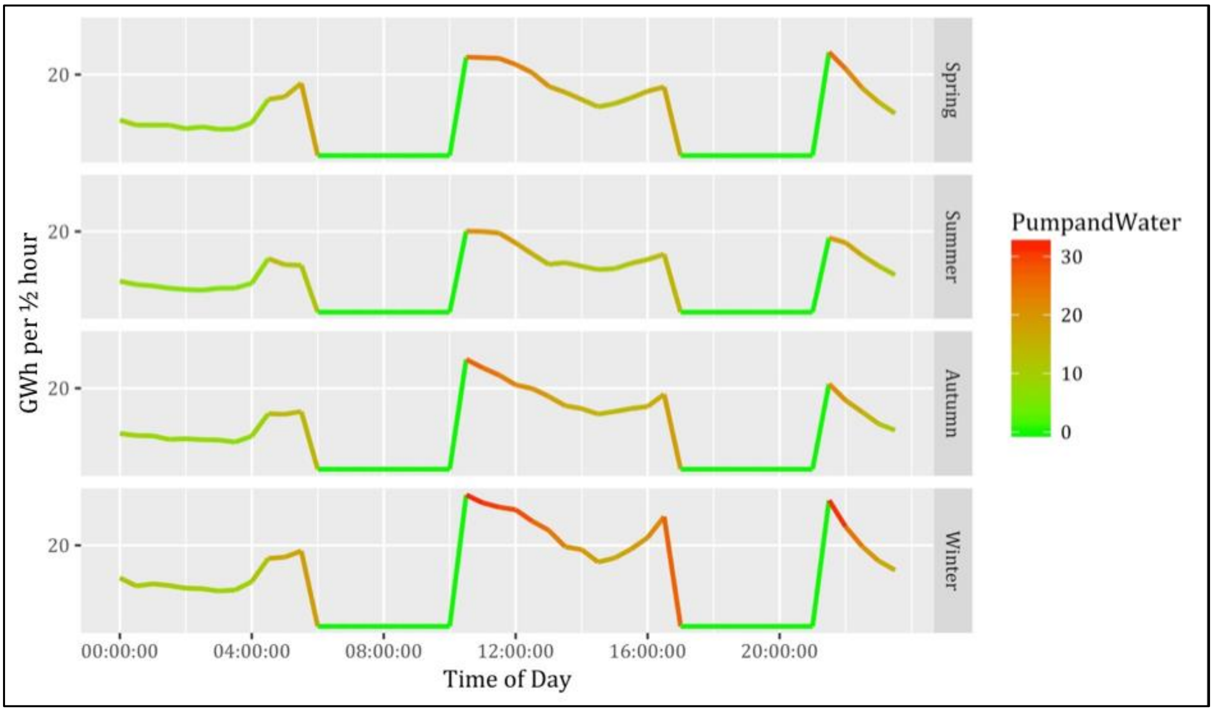
Graphic 25| HP&HW total New Zealand energy consumption per day in MWh



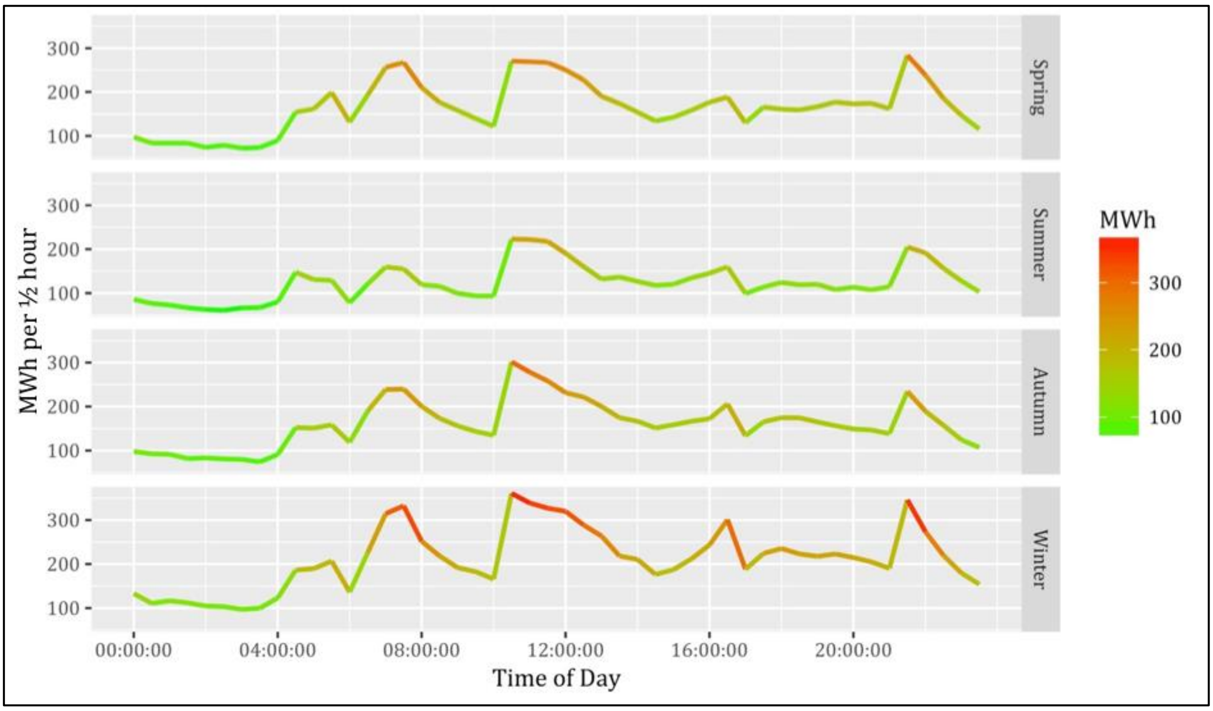
Graphic 26| HP&HW total New Zealand energy consumption per season in GWh



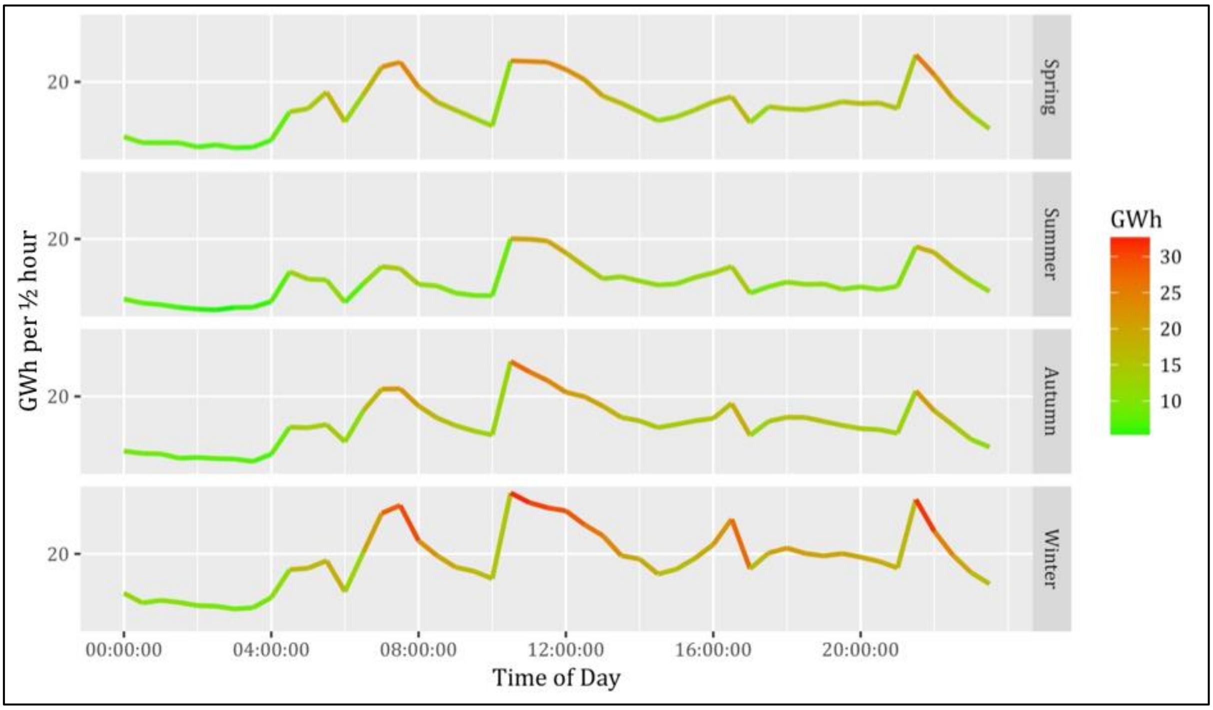
Graphic 27| HP&HW SC1 total New Zealand energy consumption per day in MWh



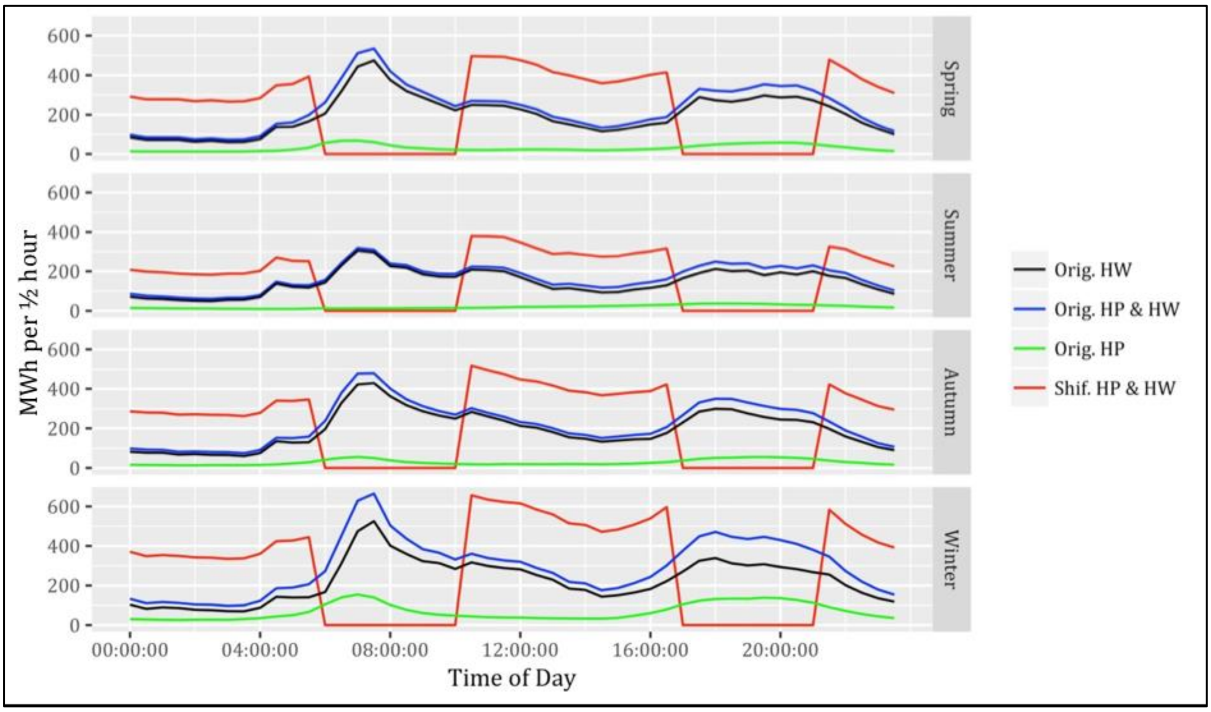
Graphic 28| HP&HW SC1 total New Zealand energy consumption per season in GWh



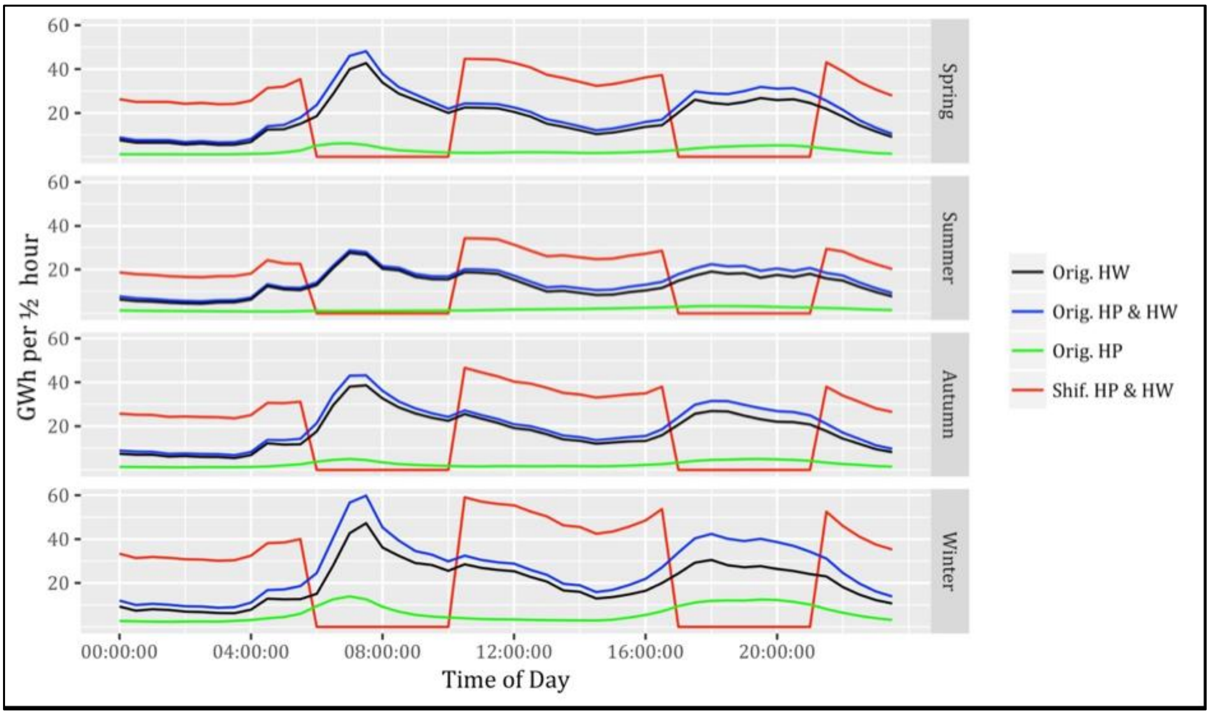
Graphic 29| HP&HW SC2 total New Zealand energy consumption per day in MWh



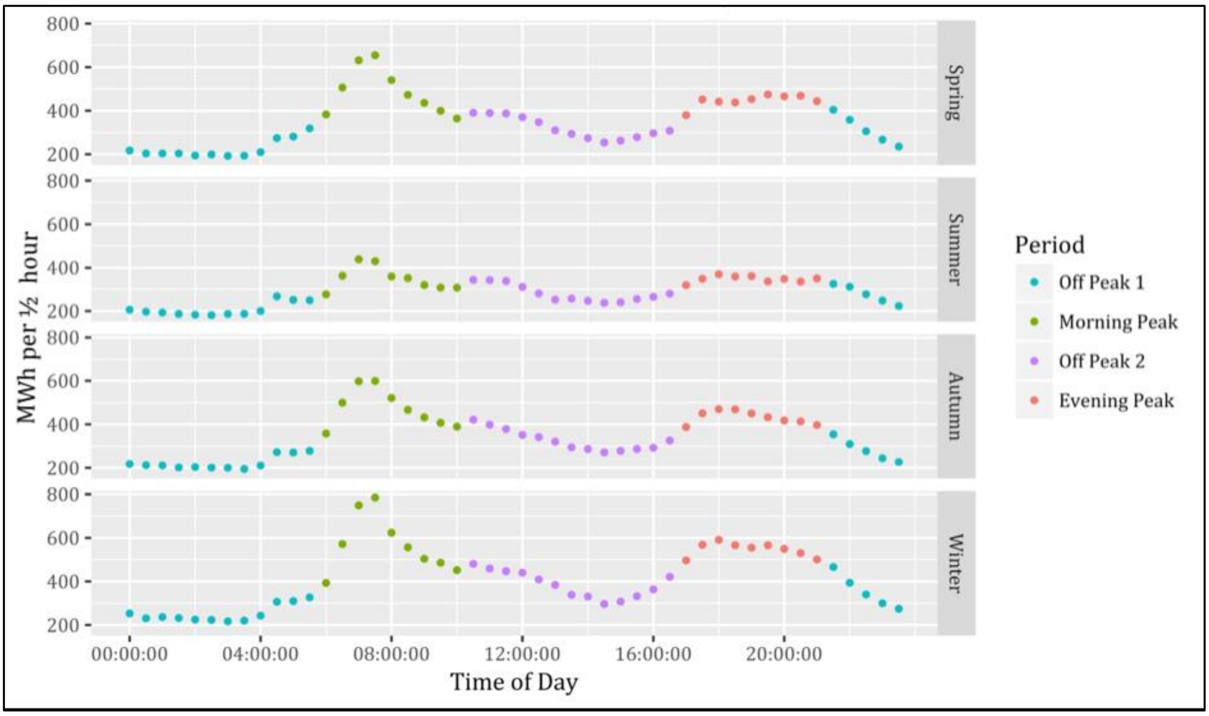
Graphic 30| HP&HW SC2 total New Zealand energy consumption per season in GWh



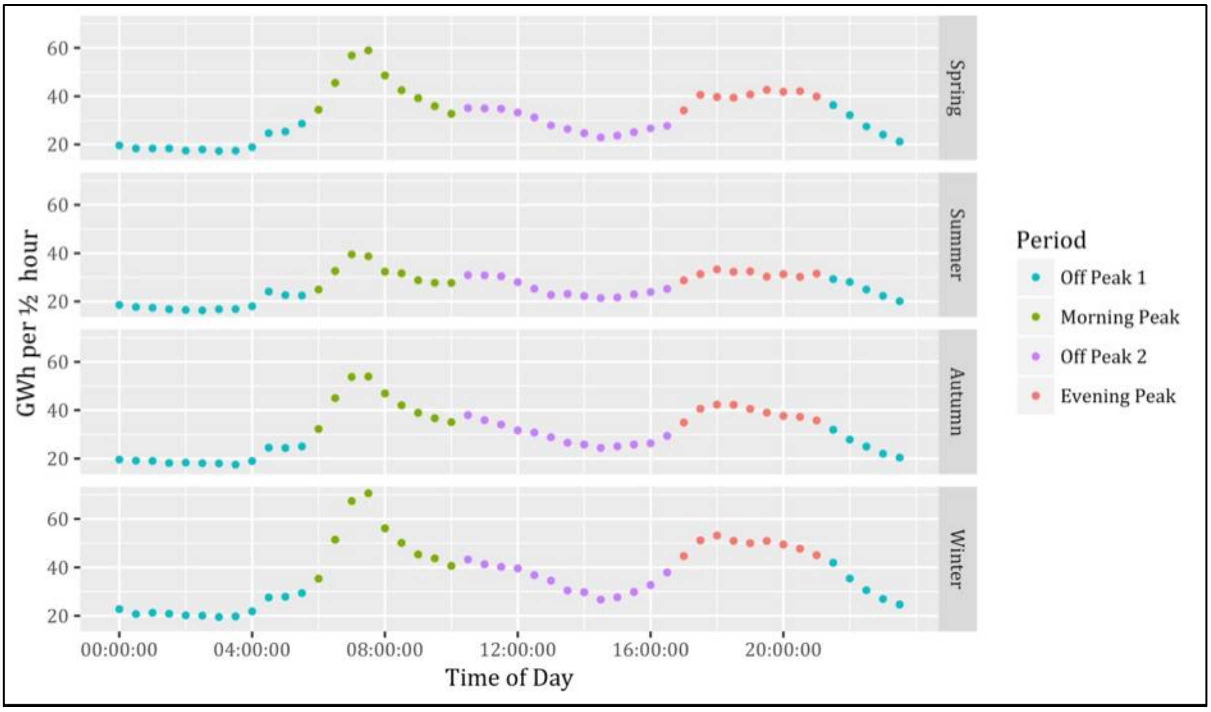
Graphic 31| HP&HW SC3 total New Zealand energy consumption per day in MWh



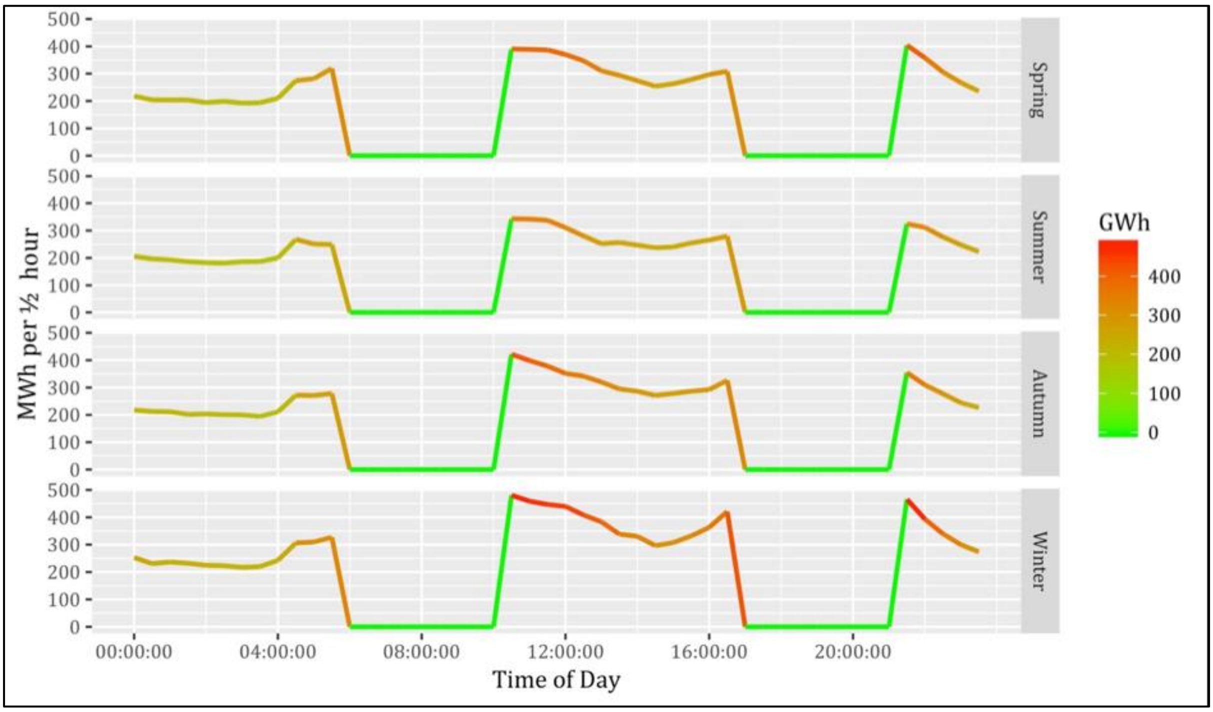
Graphic 32| HP&HW SC3 total New Zealand energy consumption per season in GWh



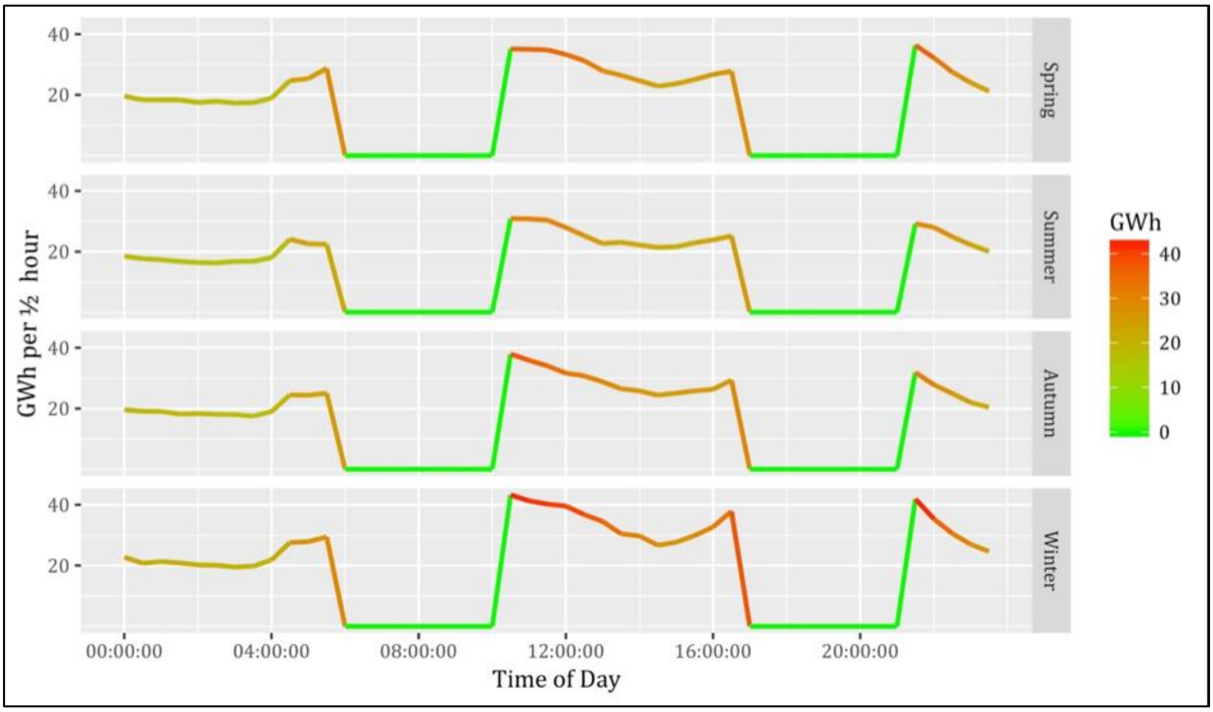
Graphic 33| HP, HW&REF total New Zealand energy consumption per day in MWh



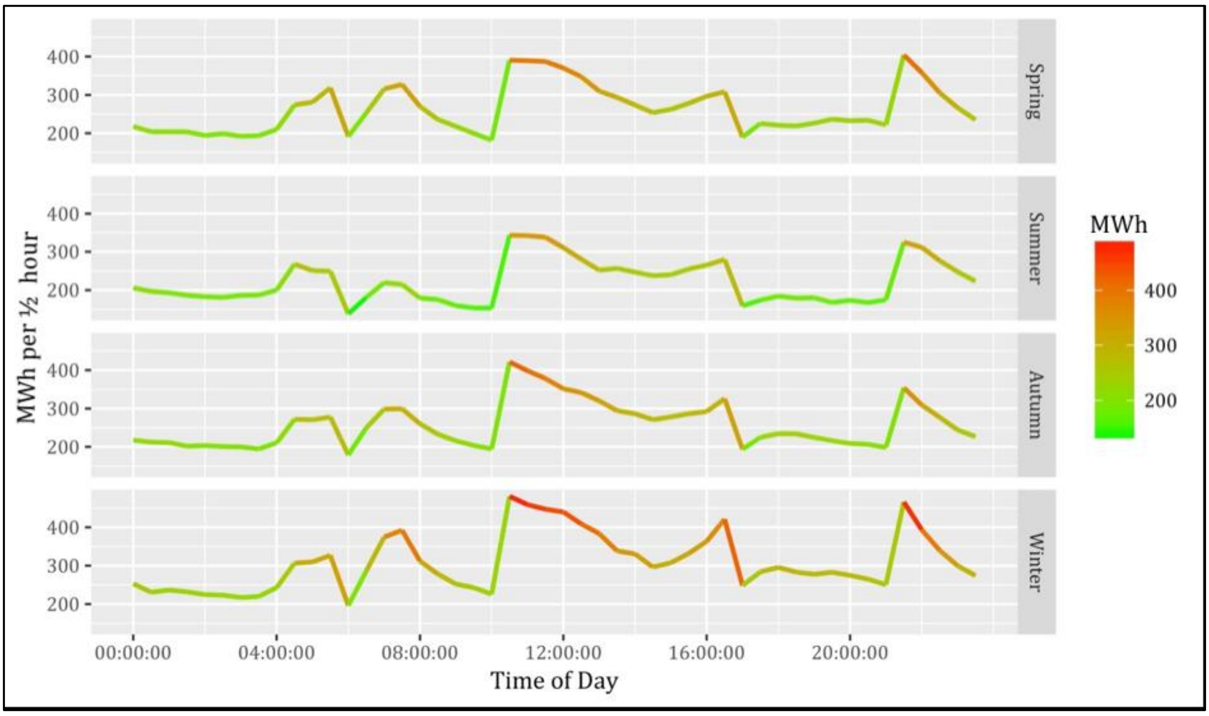
Graphic 34| HP, HW&REF total New Zealand energy consumption per season in GWh



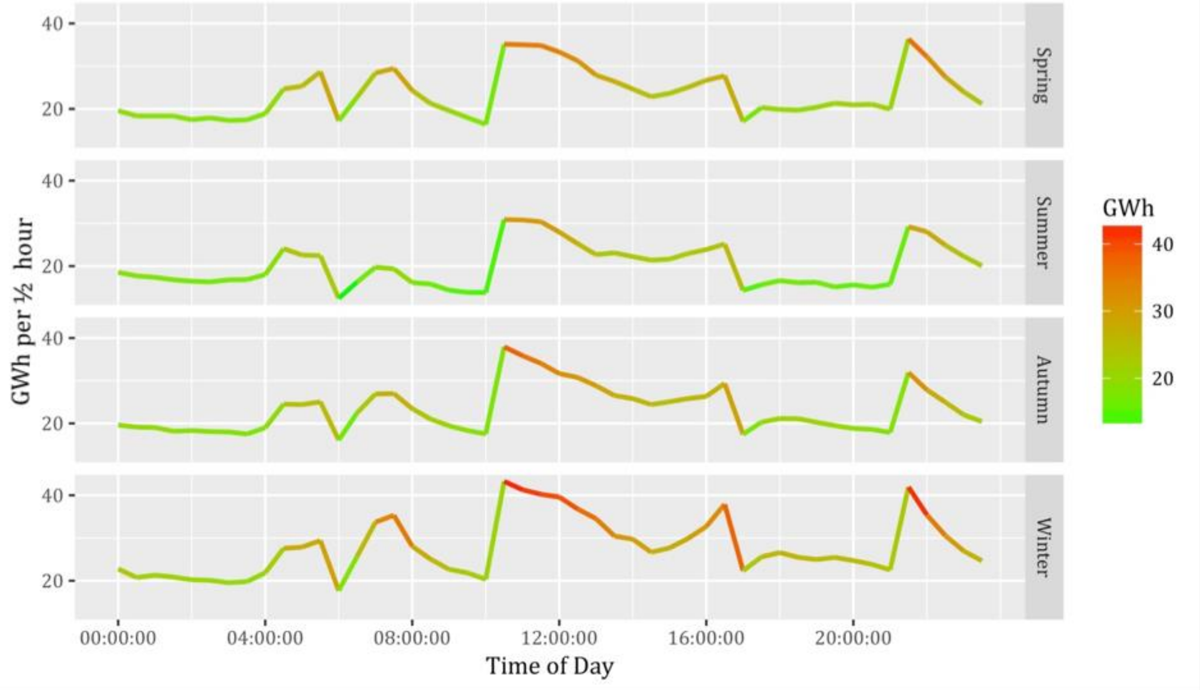
Graphic 35| HP, HW&REF SC1 total New Zealand energy consumption per day in MWh



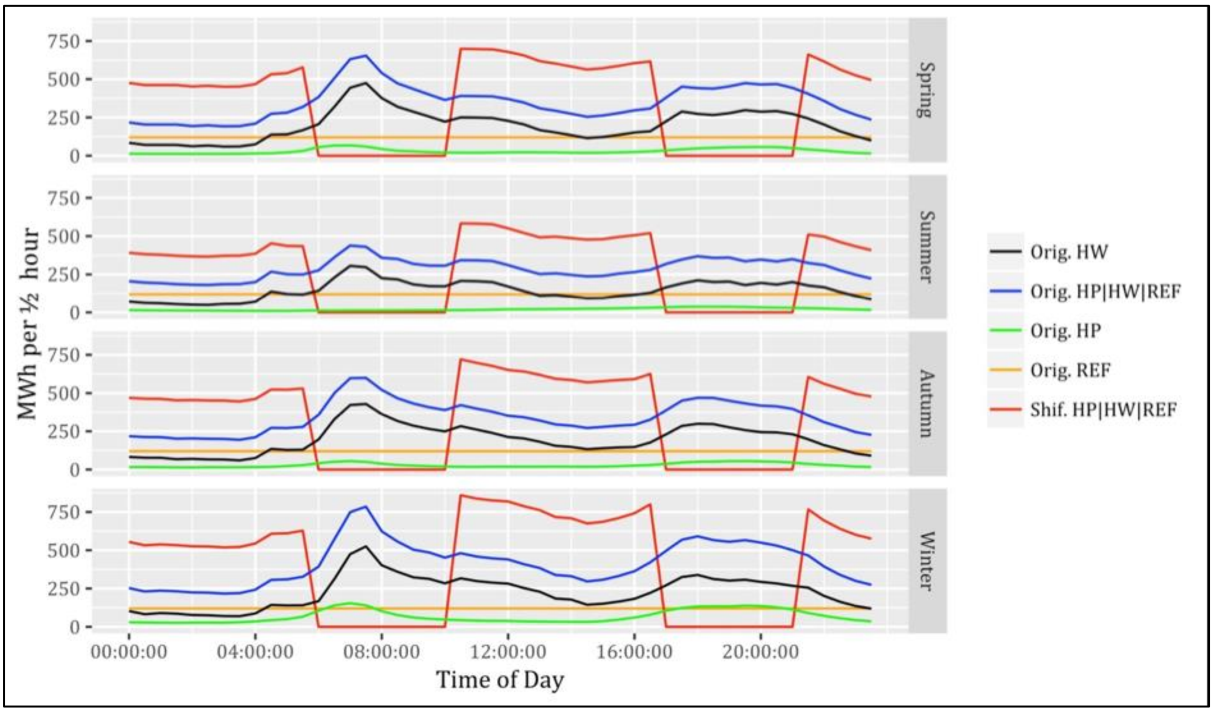
Graphic 36| HP, HW&REF SC1 total New Zealand energy consumption per season in GWh



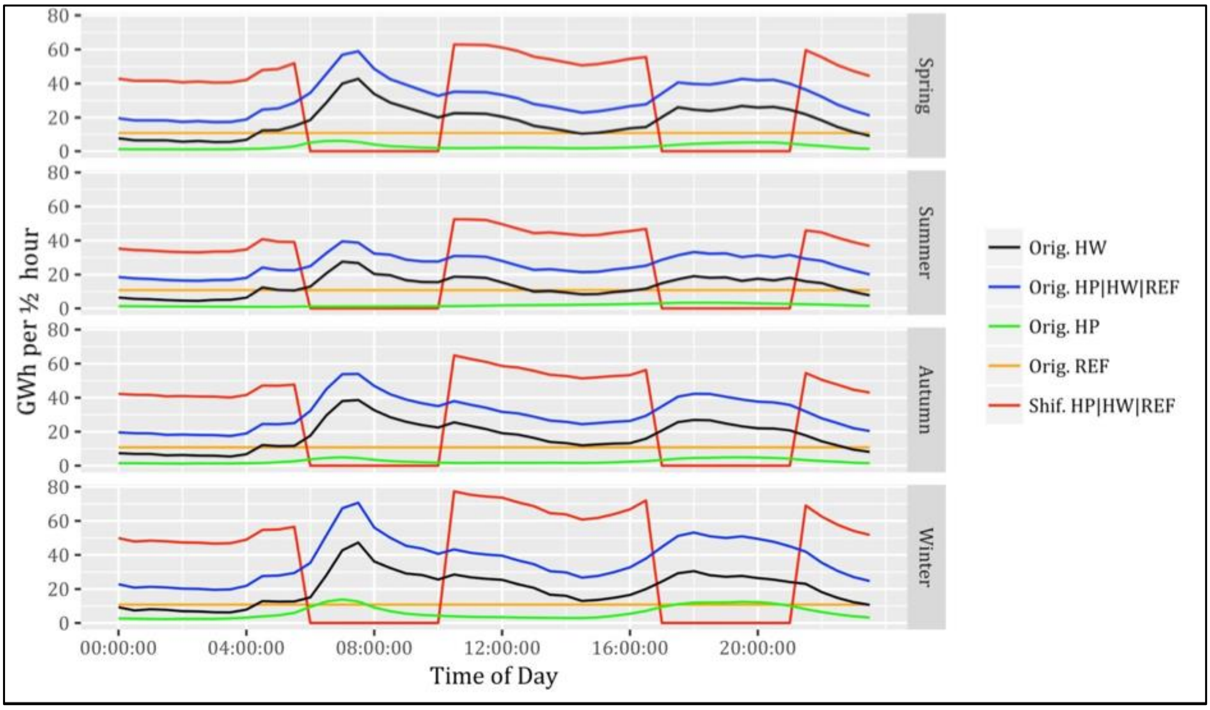
Graphic 37| HP, HW&REF SC2 total New Zealand energy consumption per day in MWh



Graphic 38| HP, HW&REF SC2 total New Zealand energy consumption per season in GWh



Graphic 39| HP, HW&REF SC3 total New Zealand energy consumption per day in MWh



Graphic 40| HP, HW&REF SC3 total New Zealand energy consumption per season in GWh