WHOLE ELECTRICITY SYSTEM COSTS

A report for Vector

25 March 2021

CONTENTS

EXECUTIVE SUMMARY

As New Zealand transitions to a low-carbon economy, the electricity sector will play an important role by allowing other sectors (notably heat and transport) to electrify and reduce carbon emissions. The Climate Change Commission's draft advice to the Government has carried out high-level modelling to show which investments in generation may be required. In the future, more detailed modelling of the sector will be required (for example, to feed into the national energy strategy that the Commission recommends is developed). It is important that this work:

- accounts for actions on the demand side (such as demand-side response, energy efficiency, and storage) which may reduce the need for investments in generation; and
- adopts a whole-system approach which accounts for the way different forms of generation of demand-side action can affect the costs of building and running the entire power system.

Frontier Economics previously carried out work for the UK Government to produce a "Whole Electricity System Cost" (WESC) metric. This extends the commonly used Levelized Cost of Electricity (LCOE) measure to incorporate wider impacts on the system, and can allow demand-side technologies to be compared alongside generation.

Vector has engaged Frontier Economics to produce an illustrative WESC for different technologies in New Zealand. Unlike the work carried out in the UK (which used a complex power system model), this analysis has built up an estimate of WESC from a few simple assumptions. This approach means that the methodology can be more readily understood, but at the expense of accuracy: these results should not be read as a definitive summary of the value of different technologies, but as an illustration of how demand-side and generation technologies can be compared alongside one another.

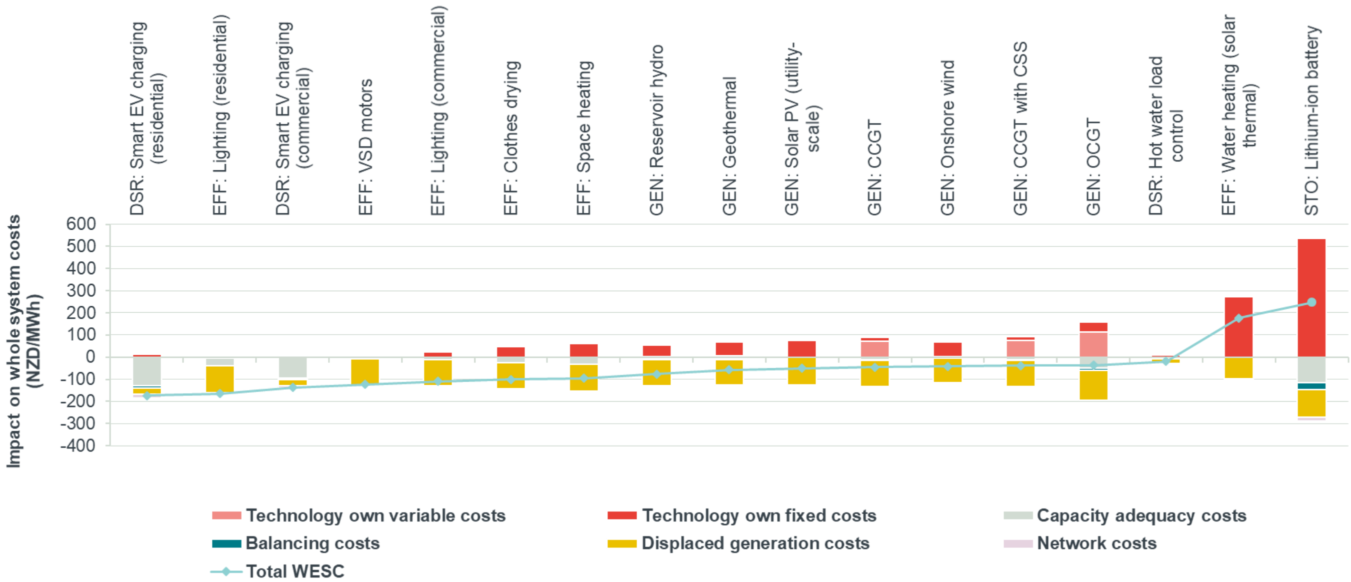
Figure 1 summarises the results. Each column relates to a different technology (whether generation or demand side). The coloured bars show the additional costs (or, if negative, reduced costs) that the technology imposes on different parts of the power system:

- **Technology own fixed and variable costs reflect** the cost of building and running the technology itself;
- **capacity adequacy costs** relate to the way in which the addition of capacity can mean other capacity can be retired (saving its fixed and variable costs) while maintaining the same security of supply;
- **balancing costs** refer to the additional costs imposed by technologies which have volatile output (requiring actions to keep electricity demand in line with supply), or the benefits of technologies that can undertake those actions;
- **displaced generation costs** refer to the reduced costs of running other generators during the periods that the technology is producing power; and
- **network costs** are the distribution network reinforcement costs that the technology may avert (we have not modelled the transmission network).

All these elements are expressed, like a levelized cost, on a $/MWh basis.

The light blue line, which is the sum of these components, is the overall system impact. It represents the change in the total costs of the electricity system when a technology is added that has a lifetime output of 1 MWh (and the rest of the system adjusts accordingly). When the blue line is below $0/MWh, adding a technology such that it produces 1 MWh over its lifetime reduces total system costs. When the blue line is above $0/MWh, it indicates that adding the technology with a lifetime output of 1 MWh increases total system costs. Technologies with lower figures will add greater benefits to the system for each MWh of energy they produce.

Figure 1 WESC estimates including balancing and distribution network impacts



Source: Frontier Economics

Note: These illustrative figures should not be interpreted as "generic" estimates of the whole system impact of a class of technologies. Whole system impacts are dependent on the wider electricity system and when technologies are assumed to be built.

While illustrative, this analysis demonstrates that:

- **Accounting for the wider impacts of technologies on the power system affects their value-for-money**. It is therefore important that comparisons between technologies are not made on the narrow basis of LCOE.
- **There are many demand-side measures which do have the potential to be more cost effective (on a MWh for MWh basis) than generation technologies)**. Energy efficiency technologies in particular may offer a particularly compelling alternative to baseload generation, and demand-side response with electric vehicles may be very cost-effective once their significant capacity adequacy benefits are taken into account.

Going forward, policymakers should ensure that demand-side technologies are considered alongside generation. This may require gathering additional data on the costs and capacities of these technologies, and ensuring that all actors in the market have incentives that accord with their overall impact on the system (as shown by metrics such as the WESC).

1 INTRODUCTION

The Climate Change Commission is consulting on its draft advice to the Government on the actions necessary to ensure New Zealand achieves the target of net zero emissions of long-lived gases by 2050.

As New Zealand transitions to a low-carbon economy, the electricity sector will play an important role by allowing other sectors (notably heat and transport) to electrify and reduce carbon emissions. The Commission has carried out modelling to produce a pathway for the electricity sector out to 2035. This pathway involves increased investment in renewable generation (particularly wind, but also geothermal and solar), and a reduction in gas generation.[1]

As is common for a long-run economy-wide model, the ENZ model used by the Commission to produce these pathways considers the electricity system at a very high level: demand for generation is characterised as either demand for baseload generation, or for flexible generation. As a result:

- The pathways do not explicitly account for all of the actions on the demand-side[2] which could reduce the need for additional generation – for example demand-side response or electrical energy storage technologies such as batteries.
- The pathways will not account for the wider costs of generation technologies. For example, the way in which different forms of generation or demand-side actions may:
  - lead to different costs of building and operating the electricity network (which will need considerable reinforcement if there is extensive electrification of heat and transport);
  - lead to different costs associated with balancing demand and supply for power on an second-by-second basis; and
  - have different impacts on generation costs depending on when in the day or the year that power can be provided.

Therefore, while the Commission's pathways are suitable for demonstrating the overall direction that is required (and showing that the decarbonisation targets are achievable) more detailed analysis will be required in the future to ensure that these factors are not overlooked. Indeed, the Commission's recommendations include further actions for the Government to develop a national energy strategy which will – among other things – "*monitor and review to ensure electricity remains affordable and accessible, and measures are in place to keep system costs down, such as demand response management.*"

Frontier Economics previously carried out work for the UK Government to produce a "Whole Electricity System Cost" (WESC) metric.[3] This extends the commonly used Levelized Cost of Electricity (LCOE) measure to take into account the wider costs of generation technologies. In 2020, we carried out further modelling for the

1 Commission report figure 3.14

2 The buildings modelling carried out by the Commission will account for some energy efficiency measures.

3 Frontier Economics for DECC (2016), *Whole power system impacts of electricity generation technologies*

ReCosting Energy project[4] which demonstrated that this metric can be used to compare demand-side technologies (energy efficiency, demand-side response, and storage) “like-for-like” with generation.

As part of its submission to the Commission’s consultation, Vector has engaged Frontier Economics to produce an illustrative WESC for different technologies in New Zealand. Unlike the work carried out in the UK (which used a complex power system model), this analysis has built up an estimate of WESC from a few simple assumptions. This approach means that the methodology can be more readily understood, but at the expense of accuracy: these results should not be read as a definitive summary of the value of different technologies, but as an illustration of how demand-side and generation technologies can be compared alongside one another. This enables us to answer the following questions:

- To what extent does accounting for the wider impact of generation and demand-side technologies affect their cost-effectiveness?
- Are there demand-side measures which may be more cost-effective than building additional generation?

The rest of this report is structured as follows:

- First, we describe how the LCOE is calculated, and explain how it can be extended into the broader WESC metric.
- We then set out the methodology used in this report to approximate the WESC of different forms of generation and demand-side technologies.
- The following section describes the different technologies that have been modelled.
- The results section presents both the LCOE and WESC for these different technologies.
- Finally, we set out the main conclusions from our analysis.

[4] Frontier Economics (2020), *Modelling Whole System Costs of Demand-Side Technologies*

2 WHOLE SYSTEM IMPACTS AND THEIR INTERPRETATION

This section describes the Levelised Cost of Electricity (LCOE) metric, and how this can be extended to estimate a Whole Electricity System Cost (WESC).

2.1 Levelised costs

Electricity generation technologies have vastly different cost structures, with different proportions of initial capital costs, fixed running costs, and variable running costs. For example:

- an open-cycle gas turbine (OCGT) has comparatively low construction and maintenance costs, but as it consumes large amounts of fuel (and emits large amounts of carbon) it has comparatively high variable costs;
- a reservoir hydro plant has no fuel or carbon costs, but a high capital expenditure; and
- a geothermal plant has no fuel costs, some carbon costs, but relatively high capital and fixed operating costs.

The **Levelised Cost of Electricity** (LCOE) metric summarises these different costs on a simple NZD per MWh basis. It is calculated as the discounted sum of all lifetime costs of a generator, divided by the discounted sum of electricity generated over its lifetime.

MBIE publishes LCOE estimates of the various potential generation projects in an interactive tool.[5] The EECA has also published a "generation equivalent cost" for energy efficiency technologies, which is calculated in the same way (but considering energy saved rather than generated).[6]

However, the simplicity of the LCOE means that it ignores the potentially important impact each technology can have on the wider system. For example, MBIE notes[7] that the LCOE "*does not take into account additional capital cost of meeting peak demand.*"

"Whole system cost" metrics have been developed to account for some of the factors neglected by the LCOE, and to allow the cost-effectiveness of different technologies to be compared on a more like-for-like basis.

2.2 From levelised costs to whole system costs

Two technologies can have the same LCOE (i.e. the same "direct" costs) but dissimilar impacts on the power system. Consider, for example, two generators with the same LCOE, but one can be dispatched flexibly, and the other produces

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5 https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-modelling/interactive-levelised-cost-of-electricity-comparison-tool/

6 EECA (2019), *Energy Efficiency First*

7 https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-modelling/interactive-levelised-cost-of-electricity-comparison-tool/

electricity intermittently. All else equal, the flexible generator adds more value to the system – or, in other words, leads to a greater reduction in the costs of operating the system – since:

- if it can be relied upon to produce electricity during the system peak or during periods of low hydro inflows, it can reduce the amount of capacity needed to be kept on standby;
- if its output can be reliably and rapidly increased or decreased it may reduce the costs of balancing the system (i.e. keeping electrical demand and supply equal to one another); and
- if it can be dispatched when electricity prices are highest, it will displace forms of generation with higher variable costs.

The **Whole Electricity System Cost** (WESC) metric takes these wider impacts on the power system[8] into account. Figure 2 describes the five categories of system costs which we will estimate as part of our WESC estimate. This framework was originally developed for the UK's Department of Energy and Climate Change[9] with further work carried out for the Energy Technologies Institute.[10] The UK's Department for Business, Energy and Industrial Strategy has adopted this type of framework to calculate what it calls "enhanced levelized costs".[11]

8 The WESC does not consider impacts beyond this (e.g. on transport, gas, or heating systems). For example, it is possible that DSR technology could reduce ownership costs of heat pumps and electric vehicles, leading to greater take-up of these assets and benefits elsewhere in the system. As this impact is beyond the power system, it is not quantified as part of the WESC.

9 Frontier Economics for DECC (2016), *Whole power system impacts of electricity generation technologies*

10 Frontier Economics for ETI (2018), *A framework for assessing the value for money of electricity technologies*

11 BEIS (2020), *Electricity Generation Costs 2020*

Figure 2 The components of Whole Electricity System Costs

Technology direct costs	Capital and operational costs associated with the incremental technology.
Displaced generation impact	Outputs from the incremental technology can displace higher marginal cost generation, producing variable cost savings, e.g. fuel, carbon. If hydro generation is displaced, this will also have an associated saving due to the opportunity cost of water. The scale of this is diminished if generators in the rest of the system operate less efficiently, or the incremental technology is curtailed.
Capacity adequacy impact	To the extent existing capacity can be retired, or new capacity forgone to ensure the same level of security of supply and carbon intensity as the counterfactual, there is a cost saving to the system.
Network impact	The incremental technology may require investments to reinforce or extend the existing grid, and changes to power flow may increase or decrease power losses due to transmission and distribution. It is also possible that technologies can free up headroom on the grid, creating network benefits.
Balancing impact	If the incremental capacity impacts on the uncertainty of supply, it will affect how generators in the rest of the system are called on to help support system stability by altering their output. It will also affect the extent to which they need to be prepared to do so at short notice, potentially affecting their staffing, fuel, and/or maintenance costs.

Source: Frontier Economics

In our previous modelling in the UK, these costs have been assessed by using a dispatch and investment model to simulate the cost of running the power system, with and without an extra generator. The resulting $/MWh figure can be interpreted as follows:

If a sufficient amount of additional generation was added to the power system to produce 1MWh of electricity, and the system adapted in response, what would be the overall impact on the costs of the system?

2.3 Uses and limitations of whole system costs

The WESC metric as described above is a significant improvement on the LCOE. However, there are still limitations that must be borne in mind when interpreting it.

First, **it is highly dependent on the scenario that is assumed for the wider system**. This is a strength of whole system costs: the value of a specific type of generation to the system will depend on the state of the system as a whole. For example, technologies that provide high levels of flexibility may be relatively more valuable in a system with a high proportion of intermittent generators. However, this does mean that there is no single WESC that will be valid in all situations. For example, the whole system impact of a technology will depend on whether a large amount of that technology has already been built.

Second, **it does not include wider impacts beyond the power system**. For example, the metric we report does not apply a value to factors such as air quality or visual impact, and does not quantify wider economic factors.

Finally, **it cannot quantify the optimal mix of technologies required for the system**. The WESC metric answers the question "*which technology can produce a MWh of electricity at lowest overall cost to the system*". However, this is not the only question of relevance to policymakers. For example, if the system were short of capacity, it may be relevant to construct a $/kW figure which answers the question "*which technology can provide a kW of firm capacity at lowest overall cost to the system*".

In general, there is no single least-cost form of generation that will be appropriate in all circumstances: a mixture of different forms of technologies, with complementary characteristics (e.g. suited for providing baseload vs flexible generation), will be required. No single number can adequately capture the relationships between different technologies. A policymaker seeking to determine the optimal pathway for decarbonisation will therefore need to use a model that takes into account all of the components of WESC, but calculates the optimal mixture of technologies.

Nevertheless, the WESC metric can still be a useful source of insights:

- The market cannot be expected to bring forward efficient investments if the incentives of investors do not match their overall impact on the system. For example, if the structure of network tariffs does not reflect the cost or value that an investor (whether in generation or a demand-side technology) imposes on the system, they may over- or under-invest. The WESC metric allows policymakers to compare the remuneration investors would have under cost-reflective conditions to what they obtain under the current market structure.
- Technologies are still frequently compared based on their LCOE. This leaves wider system impacts unquantified, making it difficult to compare technologies like-for-like (for example, the extent to which the specific daily and seasonal patterns of renewable generation may affect their value to the system). The WESC metric provides a framework by which these types of effect can be quantified.

3 MODEL METHODOLOGY

This section describes the model used to estimate the WESC for the various generation and demand-side technologies introduced in the following section.

- First, we describe the overall approach we have adopted.
- We then explain how each of the components of WESC described in Figure 2 has been approximated.
- Finally, we describe how we have defined “generation” in the context of the demand-side technologies.

3.1 Overall approach

Our previous WESC analysis in the UK relied on additional functionality which our partners LCP built into the Dynamic Dispatch Model (DDM) used by the UK Government. The DDM simulates both the long-term behaviour of investors in the power system (building and retiring capacity) as well as short-run dispatch decisions. The additional functionality allowed the DDM to output whole system costs on a marginal basis, quantifying the impact on each of the cost categories in Figure 2 were a small amount of each type of generation to be added to the system.

The analysis presented in this report is intended to provide an illustrative view of how a whole electricity system cost can differ from a levelized cost, and how representative types of demand-side technologies might compare to generation technologies. As such, we have used a much simpler approach, with basic rules and heuristics (described below) approximating each cost component.

This methodology has the advantage of being transparent – it is easier to see what is driving results than in a complex model. However, many nuances of how the market operates are not modelled (Section 3.2 of our 2018 ETI report sets out some of the drawbacks of this simpler approach).[12] The resulting figures should therefore be seen as the starting point for further analysis.

Two modelling simplifications are particularly important as they affect all components of WESC:

- We have modelled the costs and benefits of technologies as if the market conditions that prevailed in 2019 before COVID-19 (such as commodity prices, wholesale prices, and NZ ETS prices) will be constant throughout the lifetime of any new asset. In practice, these will change over the lifetime of any asset.
- As we are only modelling a single year, we are also not able to quantify the costs associated with the way in which hydro generation output may be limited during a “dry year”.

3.2 Technology direct costs

We have sourced data on the direct costs likely to be incurred by adding 1 MW of each technology to the grid. We analyse these costs separately as variable and

[12] Frontier Economics for ETI (2018), *A framework for assessing the value for money of electricity technologies*

fixed costs. Variable costs include the fuel, carbon (priced at the NZ ETS price) and other operating and maintenance (O&M) costs incurred per MWh produced. Fixed costs comprise of initial capital expenditure (capex) and annual fixed O&M costs per MW. Section 4 sets out the source of costs for each technology.

We annuitize capex by assuming the expected economic lifetime of the technology and using the project discount rate set by the Treasury for Energy infrastructure projects.[13] We use each technology's capacity factor to calculate fixed costs on a per MWh basis.[14]

This differs from our analysis in the UK, which calculated a cost of finance for each type of generation based on a per-technology hurdle rate. All else equal, the hurdle rate (the required return for investors) will tend to increase for technologies that are perceived as having a higher level of risk. Using the hurdle rate in the analysis can therefore help quantify this risk. If government policy moves the risks of some technologies away from investors, these risks will not be captured in the hurdle rates, and so in our 2018 analysis, we made an adjustment to add these risks back in. By annuitizing all investments at the same discount rate we avoid these complications, at the expense of not assigning a cost to riskier technologies.

3.3 Displaced generation impact

When a generator generates (or demand is reduced) it will displace higher marginal cost generation, producing variable cost savings. This impact depends on both the load factor of the technology in question, and the value of this electricity when it is being produced: a technology that displaces high-cost energy during the peak has a higher displaced generation benefit than one that displaces cheaper night-time energy.

For each technology, we therefore require a set of load profiles describing what percentage of the technology's nameplate capacity can produce electricity (or reduce demand) in a given trading period in a given day. We also need wholesale price data for the same trading periods on the same days.

Rather than using data on every trading period on every day in 2019, we identify five days in 2019 which are typical (in both their average wholesale price and the within-day variation in wholesale price) of a broader set of days. We then scale these five days according to the number of days that they represent.

Figure 3 contains the five representative days used in our model.

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13 Specifically we use the real pre-tax discount rate for infrastructure projects (5%). https://www.treasury.govt.nz/information-and-services/state-sector-leadership/guidance/financial-reporting-policies-and-guidance/discount-rates

14 In the case of generation technologies, we use capacity factors implied by observed output in 2019. It is likely that the capacity factors of thermal plants will decline over time, however as we are modelling a "snapshot" year we do not consider this..

Figure 3 Representative days used in the model

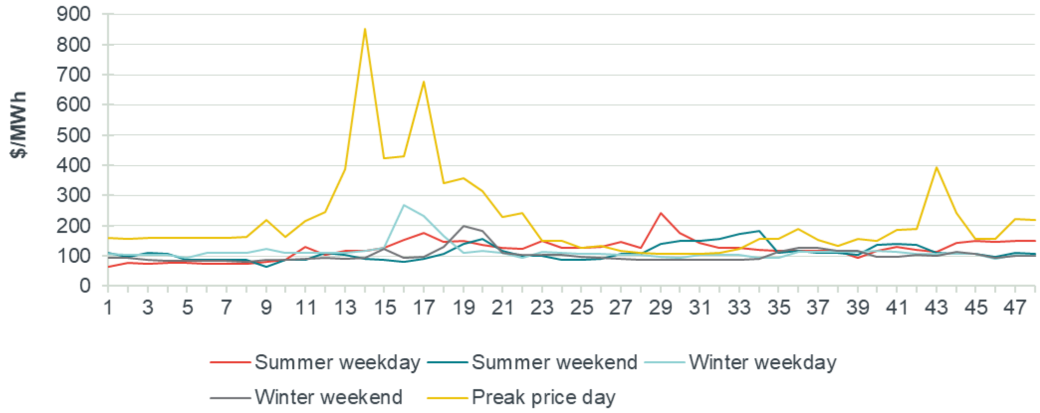
Day	Representative of	Number of days represented
29/03/2019	Summer weekday	128
03/11/2019	Summer weekend	51
30/07/2019	Winter weekday	130
06/07/2019	Winter weekend	51
19/06/2019	Price peak day	5

Source: Frontier Economics

Overall demand varies across seasons and between weekdays and the weekend; this motivates the first four representative days. The fifth representative day, “price peak day”, is intended to represent days with a significant spike in the wholesale spot price. It is important to include days such as these in the model because this is when the value of demand side response (DSR) and storage technologies are greatest – not including a small number of “peak” days would under-estimate the value of these technologies.

Figure 4 shows the evolution of prices throughout each of the representative days. Prices are higher and more volatile on the peak price day.

Figure 4 Price profile on representative days



Source: Frontier Economics

To calculate the displaced generation impact of each technology on a representative day we multiply its load profile by wholesale spot price data for the same day. Once we have calculated the value of the displaced generation on a representative day, we can scale this by the number of days represented by that representative day. Repeating this procedure for each representative day produces an estimate of the value of the generation displaced by each technology in 2019.

3.4 Balancing impact

To ensure grid frequency stays within acceptable bounds, it is essential that electricity supply and demand are kept in line with each other at all times. Transpower purchases a variety of ancillary services (including Frequency

Keeping, Instantaneous Reserve, and Over-frequency Reserve) to ensure this.[15] In addition to these specific services, the inertia provided by synchronous generators can help the system maintain stability.

In general, technologies which can respond flexibly (or provide inertia) will reduce the cost of balancing the system, while technologies that are subject to volatility in their output may increase these costs.

Some studies have previously calculated elements of these costs and benefits for particular technologies in New Zealand. For example:

- Transpower[16] has carried out analysis to quantify a variety of benefits (including the provision of different balancing services) for battery storage; and
- The GREEN Grid project has considered the impact of additional wind generation on the requirement for ancillary services.[17]

However, it has not been possible during the time available for this consultation response to produce a robust estimate of the impact of all the technologies under consideration here on balancing costs. To provide an illustrative quantification, we have therefore used figures derived from our 2020 work for ReCosting Energy in the UK. These are described in Figure 5. Clearly, the UK market is very different to New Zealand (for example, it is larger and more interconnected, but also has much less hydro generation) and so these figures should only be seen as a starting point.

[15] Transpower purchases other ancillary services (Voltage Support and Black Start) to manage other aspects of the grid.

[16] Transpower (2017), *Battery Storage in New Zealand*

[17] Schipper, K., Wood, A., Edward, C., and Milled, A. (2019), *Recommendations for Ancillary Service Markets under High Penetrations of Wind Generation in New Zealand*

Figure 5 Balancing impact assumptions

Type of generation	Impact on balancing	Benefit (cost) per kW
Dispatchable generation and storage	These technologies can provide balancing services by responding to instructions to turn up/down, and may be able to provide inertia to the system (synthetic inertia in the case of batteries)	$20 saving
Demand Side Response	DSR may also be able to provide balancing services. However, as DSR can only provide power to the system by reducing demand when it would otherwise have occurred, it may only be able to provide balancing services for a limited proportion of the day.[18]	$5 saving
Energy efficiency	By its nature energy efficiency is a persistent decrease in demand. It can neither react to solve imbalances, nor does it create volatility in demand that requires additional balancing actions.	No change
Solar generation	Solar generation cannot be turned up on demand. Unexpected variations in output due to the weather may also lead to imbalances.	($1.4 cost)
Wind generation	Wind generation cannot be turned up on demand. Unexpected variations in output due to the weather may also lead to imbalances.	($10 cost)

Source: Frontier Economics

3.5 Capacity adequacy impact

If the modelled technology allows existing capacity to be retired, or new capacity to be forgone, while maintaining the same level of security of supply, then the technology reduces the cost of the system.

We have assessed this component by estimating a Cost of New Entry (CONE) – i.e. the fixed and annualised capital costs of the cheapest available technology that is able to provide peak capacity. Based on the assumptions in our model, the CONE is based on the costs of an OCGT.[19]

To model the capacity adequacy impact of a MW of each technology we multiply the CONE (in $/MW) by the availability of each technology at the system peak. For DSR and storage technologies, we scale availability by a reliability factor. We assume that DSR technologies can be relied on to reduce capacity at the system peak 75% of the time, and that storage technologies do so 90% of the time.[20] In practice, DSR and storage are only able to reduce output or discharge for a limited period of time, which reduces their ability to support the system over an extended period. However, as we are considering the addition of a marginal increment of

[18] Some forms of DSR may be able to provide an *increase* in demand more flexibly – e.g. by charging a hot water tank or electric vehicle. However this too will be limited: It is not possible to heat up a tank that is already at max temperature, or to charge a car that is fully charged or away from the charging point.

[19] Sources underpinning our assumptions are described in Section 4. Our CONE estimate does not account for energy market and ancillary market income streams – i.e. it is a gross rather than net CONE.

[20] The reliability factor assumption for DSR is based on the results of a DSR trial as part of Northern PowerGrid's *Customer-Led Network Revolution* project.in the UK. The higher reliability factor assumption for storage technology (batteries) reflects that householders are less likely to directly interact with batteries than the DSR-enabled technologies, and so there is reduced scope for the battery to not operate as expected. For details of the DSR trail see CLNR (2014), *CLNR Industrial & Commercial DSR Trials*

technology (which will not "flatten" peak demand), our capacity adequacy calculation assumes that output is only required over a single half-hour period in order to reduce the peak. This produces a capacity adequacy benefit per MW of the technology, which is then transformed into a benefit per MWh produced by the technology.

3.6 Distribution network impact

As with our 2020 work for the ReCosting Energy project, we have not quantified the impact of technologies on transmission system costs. These are potentially very important, but may vary significantly depending on where in New Zealand a given generation asset or demand-side activity takes place.

Instead, we have focussed on the impact on the distribution networks. We assume all technologies except the generation technologies are connected to the distribution network, and have the potential to reduce load on the distribution network at the system peak, which may reduce reinforcement costs. We model the impact that each (distribution network connected) technology has if it leads to the deferment of network reinforcement capex by one year.

Vector has provided us with a cost of network reinforcement of $236 per kW (this is a long-run marginal cost calculated as cumulative system growth capex divided by changes in network capacity, between 2013 and 2019). Given the Treasury discount rate for energy infrastructure of 5%, the benefit of deferring this investment by one year is approximately $11. We multiply this by the firm availability of each embedded technology.[21]

3.7 Generation by demand-side technologies

The WESC is expressed on a NZD per MWh generated basis. Therefore, we need to define what is meant by "generation" for the demand-side technologies.

For energy efficiency technologies, generation refers to the overall reduction in electricity consumption caused by the technology. This concept is frequently referred to as "negawatts".

For the lithium-ion battery, generation represents the gross amount of electricity provided to the system when the battery is discharging. The battery will also consume additional electricity from the system when it is charging. We treat this as a cost of the gross electricity provided, which is modelled as a negative contribution to the displaced generation impact.

For DSR technologies, "generation" refers to the gross reduction in energy when demand is shifted. Like storage, DSR technologies consume additional electricity in the period demand is shifted to, and this is again modelled as a negative contribution to the displaced generation impact.

[21] The availability of DSR and storage technologies is scaled by a reliability factor as described in Section 3.5.

4 OVERVIEW OF TECHNOLOGIES

This section briefly describes the 17 technologies that have been modelled. As shown in Figure 6, these fall into four categories:

Figure 6 List of modelled technologies

Generation

- Reservoir hydro
- OCGT
- CCGT
- CCGT with CSS
- Geothermal
- Onshore wind
- Solar PV (utility-scale)

Electrical energy storage

- Lithium-ion batteries

Demand-side response

- Residential smart EV charging
- Commercial smart EV charging
- How water load control

Energy efficiency

- Lighting (residential incandescent to LED)
- Lighting (commercial fluorescent to LED)
- Space heating (resistive to heat pump)
- Water heating (solar thermal)
- Variable speed drive motors
- Efficient clothes dryers

Source: Frontier Economics

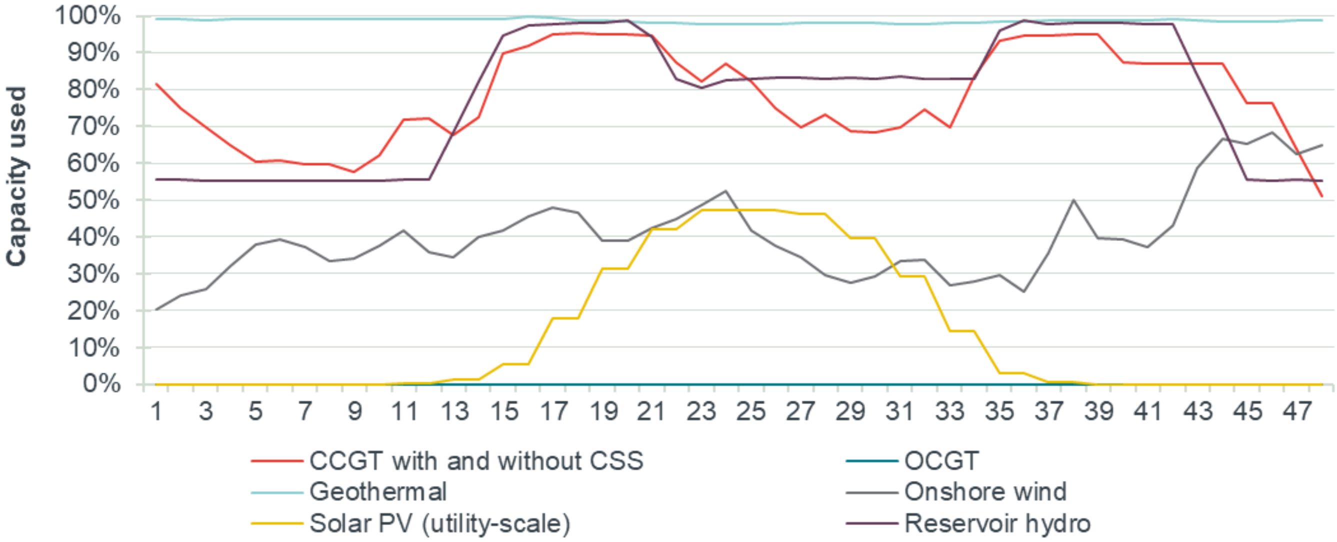
A full list of sources is available within the assumptions log of the model that accompanies this report.

4.1 Generation

All of the types of generation we have modelled are assumed to be connected directly to the transmission network, or connected to the distribution network at a sufficiently high level that they cannot be used to reduce reinforcement requirements in the distribution network. In the case of solar generation, we have not assumed any connected storage (which may be able to provide additional benefits to the network).

Figure 7 shows the load profile for each generation technology on the winter weekday representative day. Each line shows the output of each technology as a percentage of its nameplate capacity for each trading period.

Figure 7 Load profile for generation technologies on winter weekday representative day



Source: Frontier Economics

4.1.1 Reservoir hydro

Hydroelectric generation is the largest producer of electrical energy in New Zealand. For the purpose of this analysis, we have considered the value of a reservoir hydro scheme without pumped storage.

Costs have been based on an average of scheme costs reported in the 2011 generation data update produced for the Ministry of Economic Development.[22] We have based the hourly dispatch of the plant on the production for Manapouri hydro plant.

4.1.2 OCGT

Open cycle gas turbines (OCGTs) are a highly flexible form of generation, but relatively inefficient compared to CCGTs. They are therefore primarily used as peaking units.

The capex and O&M cost assumptions used in our modelling have been taken from the 2020 thermal generation update produced for MBIE.[23] The output of Huntly Unit 6 has been used as the dispatch profile.

4.1.3 CCGT

Unlike an OCGT, a CCGT (combined cycle gas turbine) adds a further steam turbine to generate electricity from what would otherwise be wasted heat.

The cost figures for CCGTs are taken from the 2020 thermal generation update, with output from Huntly Unit 5 used as the dispatch profile.

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[22] Parsons Brinckerhoff for MED (2011), *2011 NZ Generation Data Update*

[23] WSP for MBEI (2020), *2020 Thermal Generation Stack Update Report*

4.1.4 CCGT with CCS

The addition of carbon capture and storage (CCS) technology to a CCGT avoids the vast majority of carbon emissions (and associated NZ ETS payments), but leads to increased running costs.

Based on the assumptions in our model, these two changes cancel out to produce a variable cost which is very similar to a CCGT plant without CCS. We therefore continue to use the dispatch profile of Huntly Unit 5. This assumption is only likely to be reasonable while ETS payments remain at the current level – were ETS payments to increase, we would expect the load factor of unabated CCGTs to decrease below those with CCS, due to the resulting higher variable costs.

4.1.5 Geothermal

Geothermal power plants extract heat from under the surface of the earth, providing a baseload source of power.

Our assumptions on the cost of geothermal generation are primarily taken from a recent MBIE report.[24] We use the output of the Te Mihi power station as representative of the dispatch profile of a geothermal station.

4.1.6 Onshore wind

New Zealand currently has nearly 700MW of installed wind generation capacity, supplying around 6% of annual electricity generation.[25]

Our model uses Australian cost data from a report produced for AEMO,[26] while the output profile is based on the West Wind farm.

4.1.7 Solar PV (utility-scale)

Costs for a large solar PV installation are taken from a recent report for MBIE.[27] A generation profile has been derived using data from NIWA's solar energy calculator[28] for a location in Marlborough. As noted above this generation has been modelled without storage.

4.2 Electrical energy storage

We have modelled one form of electrical energy storage, a lithium-ion battery.

Figure 8 shows the lithium-ion battery's load profile on the winter weekend representative day. The red line shows the power that the battery discharges to the grid in each trading period as a percentage of its continuous power rating. The teal line shows the power the battery takes from the grid when it is charging.

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[24] Lawless Geo-Consulting for MBIE (2020), *Future Geothermal Generation Stack*

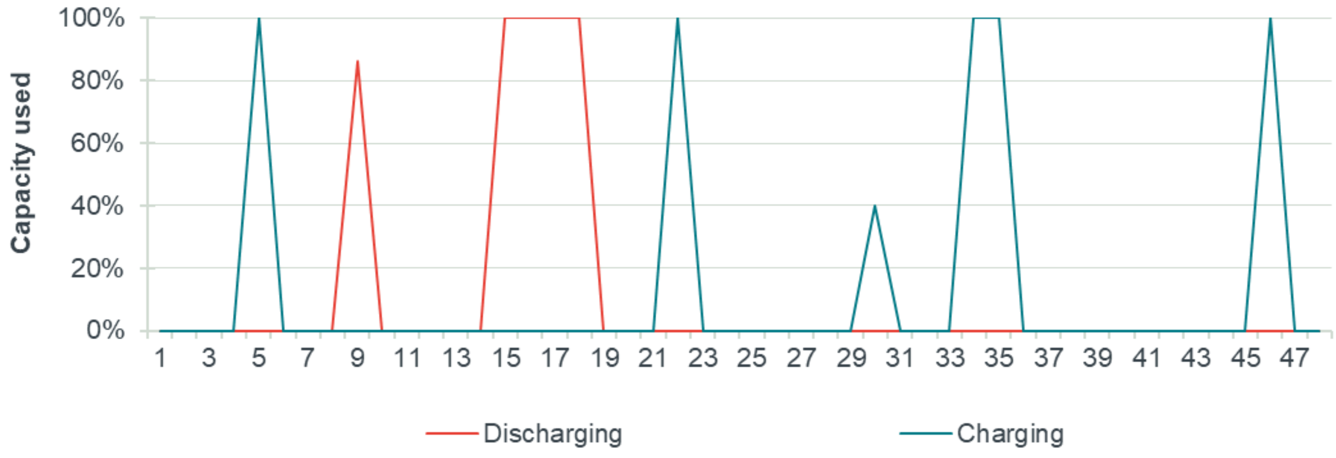
[25] New Zealand Wind Energy Association https://www.windenergy.org.nz/wind-energy/nz-windfarms accessed on 9th March 2021

[26] GHD for AEMO (2018), *AEMO Costs and technical parameter review*

[27] Allan Miller Consulting for MBIE (2020) *Economics of Utility-Scale Solar in Aotearoa New Zealand*

[28] https://solarview.niwa.co.nz/, accessed on 2nd March 20201

Figure 8 Load profile for the lithium-ion battery on winter weekday representative day



Source: Frontier Economics

4.2.1 Lithium-ion battery

The model includes one electrical energy storage technology, a Tesla Powerwall 2 battery. Operational information has been taken from Tesla's website,[29] while we have assumed a capex of $18,300 ($15,250 equipment costs plus an assumed additional 20% for installation costs).

This type of battery is typically installed alongside a domestic solar installation. A large array of such batteries can also be used to provide storage on the distribution network (for example, Vector has a 1MW/2.3MWh installation at Glen Innes in East Auckland). Such larger installations may benefit from economies of scale, however, we do not model these, and instead assume that the cost per MW of capacity is the same as a domestic installation. Batteries may be able to offer particular benefits in combination with solar PV, by shifting the power output to better match peak demand. However, we have not modelled the impact of combinations of technologies.

We have assumed that the battery is charged during times of low prices, and discharged during times of high prices, providing that the price differential is sufficient to outweigh the efficiency loss of storage.

4.3 Demand-side response

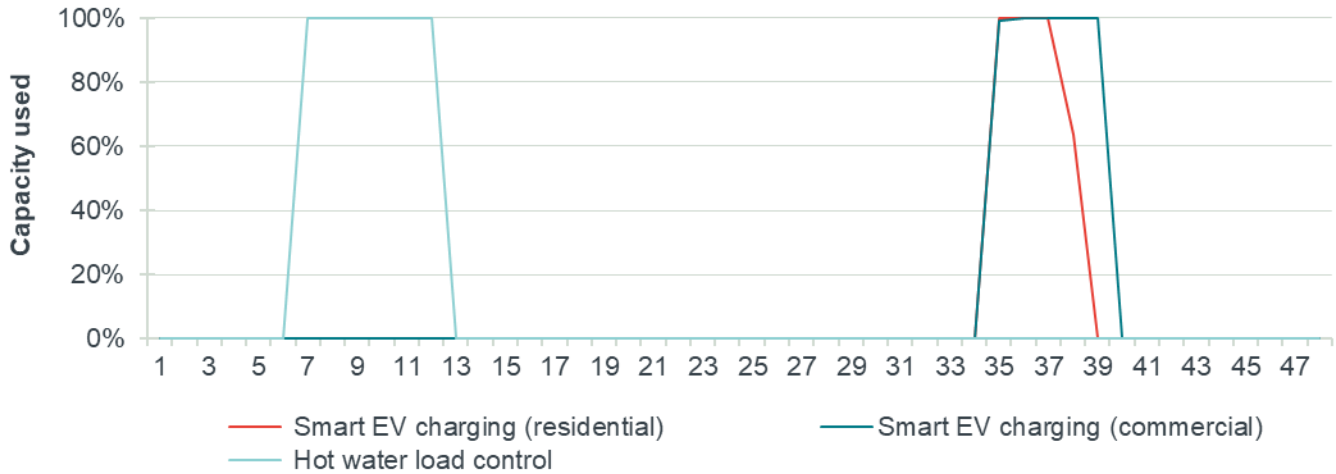
Demand-side response (DSR) refers to actions which produce a temporary reduction in demand. This will often (but not necessarily) be offset by an increase in demand at another time.

DSR can be "static" (when the same demand shifting occurs every day, for example driven by a simple time-of-use tariff) or "dynamic" (where DSR can be dispatched at short notice). All of the forms of DSR considered in this report are dynamic.

[29] https://www.tesla.com/en_nz/powerwall, accessed on 8th March 2021

Figure 9 shows the load profile for DSR technologies on the winter weekday representative day. Each line shows the amount of demand being displaced in each trading period as a percentage of the technology's capacity. For example, 1 MW of hot water load is displaced between trading periods 7 and 12.

Figure 9 Load profile for DSR technologies on "winter weekday" representative day



Source: Frontier Economics

4.3.1 Hot water load control

Many buildings use an electric immersion heater within a cylinder to provide hot water. Providing the system is sufficiently insulated, the water can be heated up overnight, and used during the daytime.

There is flexibility regarding exactly when the hot water tank is recharged, and so DSR can be used to time this in a way which creates least cost to the system. Historically, this has been carried out using either ripple control (sending a signal through the power cables themselves) or a pilot wire (a separate cable carrying a control signal). Using these systems, an EDB can signal for hot water heaters (and potentially other devices) within an area to turn on or off. However, while these systems are still widely used, there has been a decline in the connected load (caused in part by retailers and metering equipment providers removing the necessary equipment from consumers' premises).[30]

For the purpose of this modelling, we have considered a hot water tank which is on a simple timer set to run from 3am to 6am every day. We have then assessed the benefits to the network of enabling remote control.

Based on the EECA's report, we assume that the incremental cost of enabling remote control of a hot water tank is the $300 required to install a ripple relay (which will last 30 years). However, if similar functionality is embedded in smart meters or home energy management systems (HEMS), the costs could be significantly lower.

[30] EECA (2020), Ripple Control of Hot Water in New Zealand

4.3.2 Smart EV charging (residential)

By default, many owners of electric vehicles are likely to plug them in them as soon as they are back at their home. For a typical commuter, this would lead to an increase in electrical demand during the early evening.

In most cases, the consumer will not care when the car is charged, so long as it is available for the following morning's commute. A smart EV charger can therefore charge the car overnight, at a point when it is most cost effective to do so.

We have assumed that the smart EV charger can be dispatched remotely, and can therefore be used for balancing activities (by temporarily turning off the charger if required). However, we have not assumed any vehicle-to-grid functionality: while the load from the car can be reduced, the car is not able to return power to the network.

We have assumed that the cost of enabling smart EV charging is the same as hot water control (i.e. a one-off cost of $300, which will then last for 30 years). This is somewhat higher than the £300 (approximately $580) for the "intelligent control box" used for a UK trial of smart electric vehicle charging,[31] although we would expect the cost for a commercially available smart EV charging system to be considerably lower than for equipment used as part of a small-scale trial.

4.3.3 Smart EV charging (commercial)

Businesses which own fleets of EVs (for example vans at a depot) may by default charge them as soon as the working day is over. Similar to the residential smart EV charging described above, we model a smart charger which can defer this to overnight.

We have used the same cost assumption as for the residential smart charger.

4.4 Energy efficiency

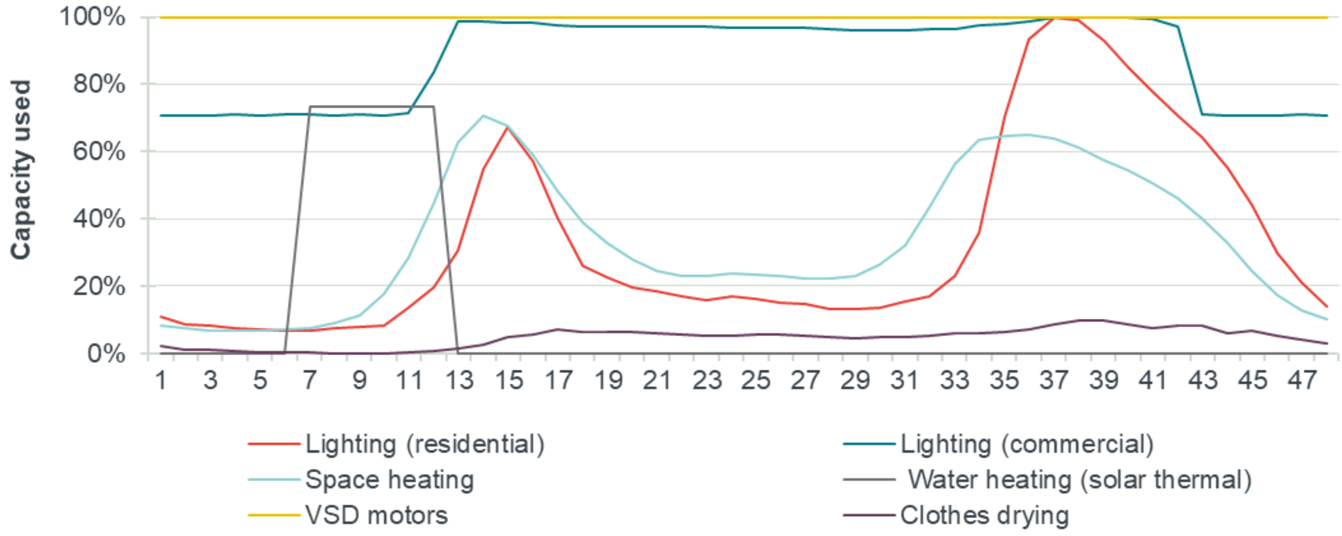
Energy efficiency relates to a permanent reduction in electrical demand – for example by replacing an older appliance with a newer one which can produce the same outputs using less energy.

Unlike DSR, energy efficiency cannot be dynamically dispatched, and is therefore unsuited for providing balancing actions.

Figure 10 shows the load profile for the energy efficiency technologies on the winter weekday representative day. It shows the proportion of the maximum possible load reduction (1 MW) that is realised in each trading period on the winter weekday representative day.

[31] SSEPD and EA Technology's *My Electric Avenue* project. This cost was reported in the 2015 working paper by Quiros-Tortos and Ochoa "*Work Activity 5 "Esprit-Enabled Deterministic Impact Studies*"

Figure 10 Load profile for efficiency technologies on "winter weekday" representative day



Source: Frontier Economics

4.4.1 Lighting (residential incandescent to LEDs)

Residential lighting demand is highest during winter evenings,[32] which coincides with the wider system peak. We have modelled the reduction in demand associated with replacing an older incandescent bulb (which has reached the end of its life) with an LED bulb.

Note that many bulbs in homes will be compact fluorescent (CFL) bulbs, and the benefit of replacing these with LEDs will be lower.

4.4.2 Lighting (commercial fluorescent to LEDs)

Many commercial buildings will be lit with fluorescent tubes, which may be on during the workday. We have used load profile data from a UK supermarket (offset by six months to ensure the seasonal pattern is appropriate for New Zealand). We have then modelled the reduction in electrical demand caused by replacing the lighting, at the end of its life, with LED fixtures.

4.4.3 Space heating (residential heat pumps)

Many homes in New Zealand are heated using direct electric resistive heaters. A heat pump can heat a building more efficiently by transferring heat from outside.

For the purpose of this modelling, we have considered the reduction in electricity usage caused by replacing resistive heating in a living area with an air-to-air heat pump (i.e. one that transfers heat energy from the air surrounding the property into warm air that is blown into the room).

Based on the EECA *Energy Efficiency First* study, we have assumed that the heat pump can produce the same output with a saving of 59% of electricity consumption.

[32] Dortans, Jack, Anderson and Stephenson (2020), *Lightening the load: quantifying the potential for energy-efficient lighting to reduce peaks in electricity demand*, In Energy Efficiency (2020) 13:1105–1118

Cost data has also been taken from this report. We have based the profile of electricity usage over the days and year on a UK dataset.[33]

4.4.4 Water heating (solar thermal)

Solar thermal collectors can provide hot water, reducing the amount of energy that needs to be consumed for an immersion heater.

We have considered the impact of a solar thermal installation for a property using a 3kW hot water cylinder which would usually heat up between 3am and 6am. Based on the EECA's Energy Efficiency First report (which we also use for cost data),[34] this could save 70% of electricity consumption. We have assumed that daily hot water production has a seasonal pattern which varies in proportion to the solar PV profile described above.

4.4.5 Motors with variable speed drive

A variable speed drive motor can operate at the optimal speed for the connected load, without the need for gearboxes. This can lead to significantly reduced power consumption.

The EECA report suggests that the use of VSD could reduce power consumption by 25%. We have assumed that the motor is in a pump running 24 hours a day (an application particularly suited for VSD).[35]

4.4.6 Clothes drying

One example of a domestic appliance which can benefit from greater efficiency is an electric clothes dryer. We have used the EECA report for data on the resulting savings and costs.

The profile of demand has been based on a UK trial, which measured the combined consumption of households' "wet appliances" (dryers, as well as washing machines and dishwashers).[36]

[33] Watson and Buswell (2019), *Decarbonising domestic heating: What is the peak GB demand?* In Energy Polcy vol 126. This provides a gas consumption profile, which for the typical UK household will primarily be used for space heat. We have offset the data by 6 months to account for the UK being in the Northern hemisphere.

[34] EECA (2019), *Energy Efficiency First*

[35] Carbon Trust (2014), *Motors and drives: A guide to equipment eligible for Enhanced Capital Allowances*

[36] Northern PowerGrid's *Customer-Led Network Revolution* project.

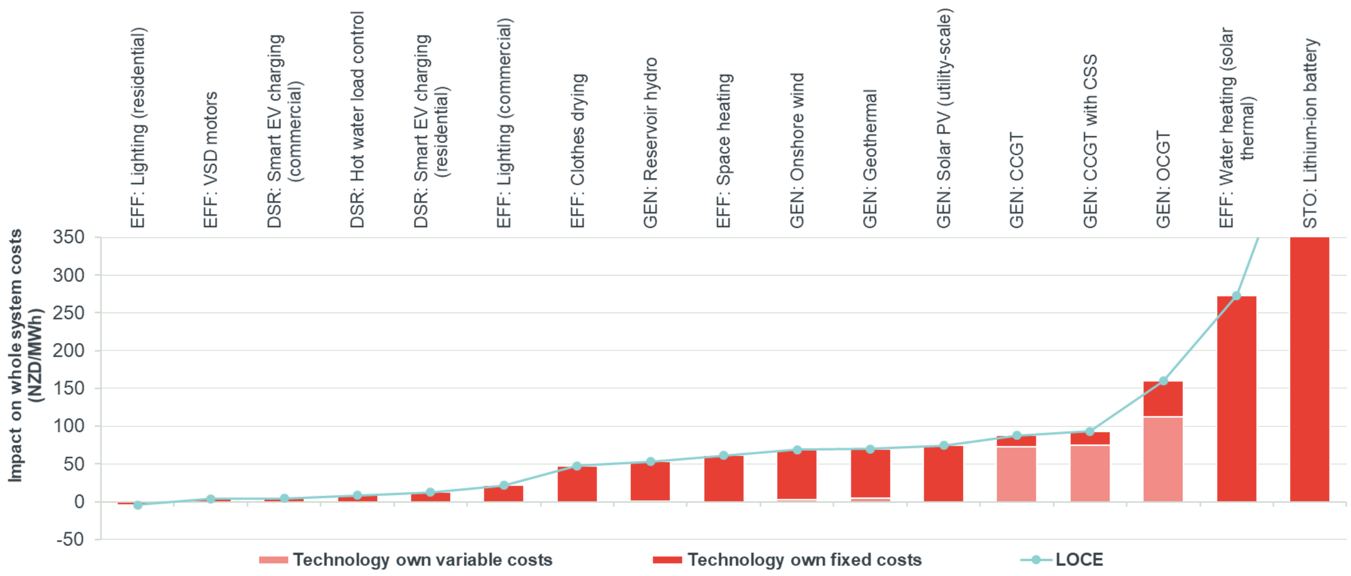
5 MODEL RESULTS

This section presents estimates of the LCOE and WESC for each modelled technology. Since WESC is an extension of the LCOE, we first present the LCOE for each modelled technology, before adding on the other components of the WESC. The WESC is presented with and without distribution network and balancing impacts.

5.1 LCOE estimates

Figure 11 presents LCOE estimates, which are split into fixed cost and variable cost components. The fixed cost component includes both annuitized capex per MWh as well as fixed O&M costs.

Figure 11 LCOE estimates



Source: Frontier Economics

Note: These illustrative figures should not be interpreted as "generic" estimates of the whole system impact of a class of technologies. Whole system impacts are dependent on the wider electricity system and when technologies are assumed to be built.

Our objective is not to produce definitive LCOE estimates for a set of generation technologies. Rather, our goal is to produce a set of WESC estimates for generation and demand-side technologies with a common set of assumptions. The figures above should not therefore be used as a source for other analysis. However, as shown in Figure 12, the LCOE estimates for generation technologies fall within the range of LCOE estimates produced by using the default assumptions on MBIE's levelized cost tool.

We should not expect our LCOE estimates and those of MBIE to align perfectly. MBIE's LCOE estimates include a corporate income tax component and HDVC Inter-Island link costs (where applicable). The latter, as a transmission network cost, is outside of the scope of this analysis, and the former represents a transfer payment rather than a resource cost. We also do not have full sight of the assumptions used by MBIE to derive their estimates, which may vary from those we have used.

Figure 12 Comparison between our generation LCOE estimates and those in MBIE's interactive LCOE tool (NZD)

Generation technology	Our LCOE estimate	MBIE's LCOE estimate range
CCGT	87.59	81.68 – 93.65
CCGT with CSS	93.34	Not available
OCGT	160.02	173.82 – 179.60
Geothermal	69.84	67.49 – 126.77
Onshore wind	68.86	53.94 – 90.82
Solar PV (utility scale)	74.26	69.67 – 127.62
Reservoir hydro	53.27	55.61 – 116.24

Source: *Frontier Economics calculations and MBIE's interactive levelised cost tool*

Note: *MBIE's LCOE estimates include HVDC Inter-Island link costs (where applicable) and an allowance for corporate income tax. Our estimates do not include these components*

Figure 13 compares our LCOE estimates for energy efficiency technologies and those presented by the EECA in its *Energy Efficiency First* report. The Figure shows that our LCOE estimates are sometimes noticeably different to those produced by the EECA.

Our lighting (residential) estimate differs from the EECA's estimate (and is actually negative) because we assume that incandescent lights are replaced with LED bulbs. Although LED bulbs are still slightly more expensive than incandescent, they have an much longer average lifetime, and so on the basis of capital costs alone are now more cost-effective. It is unclear why the EECA estimate differs (for example, it may also be considering the impact of replacing compact fluorescent bulbs with LEDs).

We also observe that the capacity factor reported by the EECA for some efficiency technologies (water heating and VSD motors) are significantly lower than the capacity factor we have assumed (or modelled).

Figure 13 Comparison between our efficiency LCOE estimates and those in the EECA's *Energy Efficiency First* report (NZD)

Efficiency technology	Our LCOE estimate	EECA's LCOE estimate
Lighting – residential	-4.47	51.60
Lighting – commercial	21.50	13.40
Space heating	61.29	63.90
Water heating	273.24	811.20
VSD motors	3.76	31.30
Clothes drying	47.66	62.30

Source: *Frontier Economics and EECA's Energy Efficiency First report*

We can use Figure 11 to compare the LCOE of generation, DSR, efficiency and storage technologies. As with any LCOE calculation, this considers the technology direct costs alone. The following insights emerge:

- Efficiency and DSR technologies are generally more cost effective than generation and storage technologies on a per MWh of electricity produced basis. All DSR and most efficiency technologies have lower direct costs per MWh than the most cost efficient generation technology (reservoir hydro), although this is a somewhat unfair comparison for DSR as the additional energy consumed when the load is shifted to is not included.

- However, efficiency technologies are not equally cost effective. For example, the use of solar thermal water heating appears to be less cost effective on this measure than all generation technologies. Space heating efficiency (moving from direct electric resistive to air-source heat pumps) is also shown as less cost effective on a $/MWh basis than reservoir hydro generation.
- The Lithium-ion battery is the least cost effective technology on this basis by a clear margin. However this is not surprising – as described in Transpower's report,[37] storage technologies are most cost-effective when they are able to "stack" multiple sources of value. In addition, the load factor of the battery is relatively low. As we are expressing the figures per MWh of energy discharged, a small per-kW cost can appear large when divided by energy production. As described in section 2.3, the WESC answers the question "which technology is most cost-effective at providing energy". Batteries and other technologies with low load factors may look more cost-effective if compared on $/kW basis.

5.2 WESC estimates

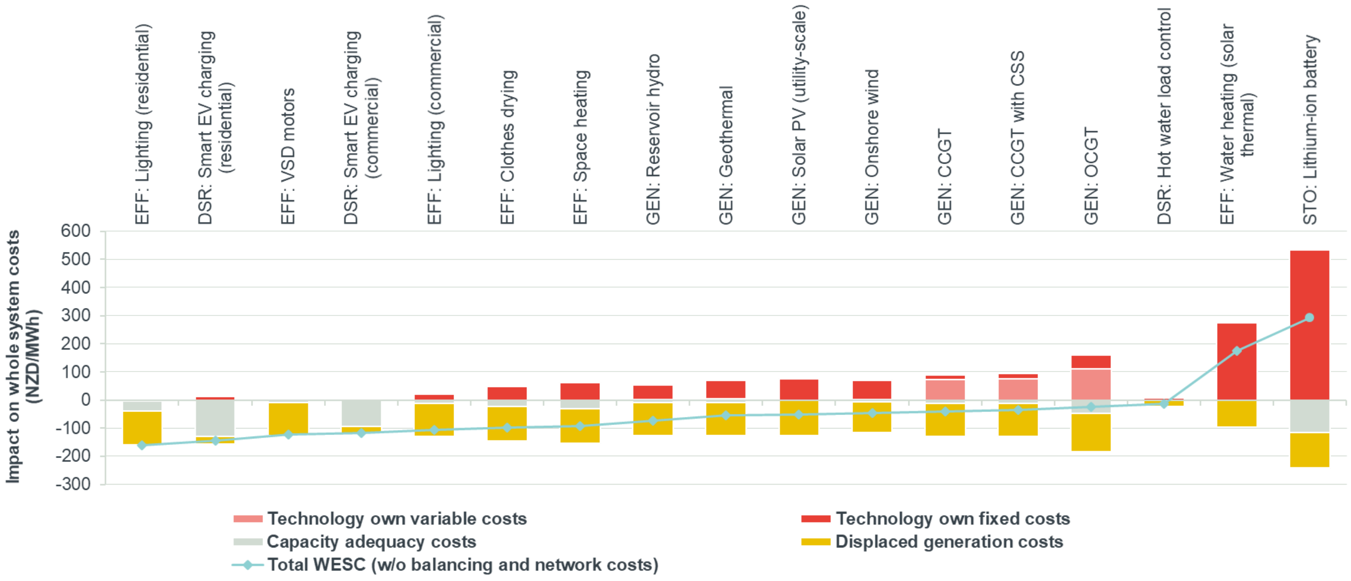
As discussed in Section 2, the LCOE metric does not account for the wider system impact of the technologies. For example, while an OCGT plant does not generate large amounts of energy, it does so during times of peak demand so it will have a disproportionately high capacity adequacy benefit. The following figures add the other components of the WESC to the analysis.

To begin with, we have added on the capacity adequacy and displaced generation impacts. Figure 14 presents the resulting WESC estimate. Each component of the whole system impact is shown a separate bar.

The light blue line, which is the sum of these components, is the overall system impact. It represents the change in the total costs of the electricity system when a technology is added that has a lifetime output of 1 MWh (and the rest of the system adjusts accordingly). When the blue line is below $0/MWh, adding a technology such that it produces 1 MWh over its lifetime reduces total system costs. When the blue line is above $0/MWh, it indicates that adding the technology with a lifetime output of 1 MWh increases total system costs. Technologies with lower figures will add greater benefits to the system for each MWh of energy they produce.

[37] Transpower (2017), *Battery Storage in New Zealand*

Figure 14 WESC estimates excluding balancing and distribution network impacts



Source: *Frontier Economics*

Note: *These illustrative figures should not be interpreted as "generic" estimates of the whole system impact of a class of technologies. Whole system impacts are dependent on the wider electricity system and when technologies are assumed to be built.*

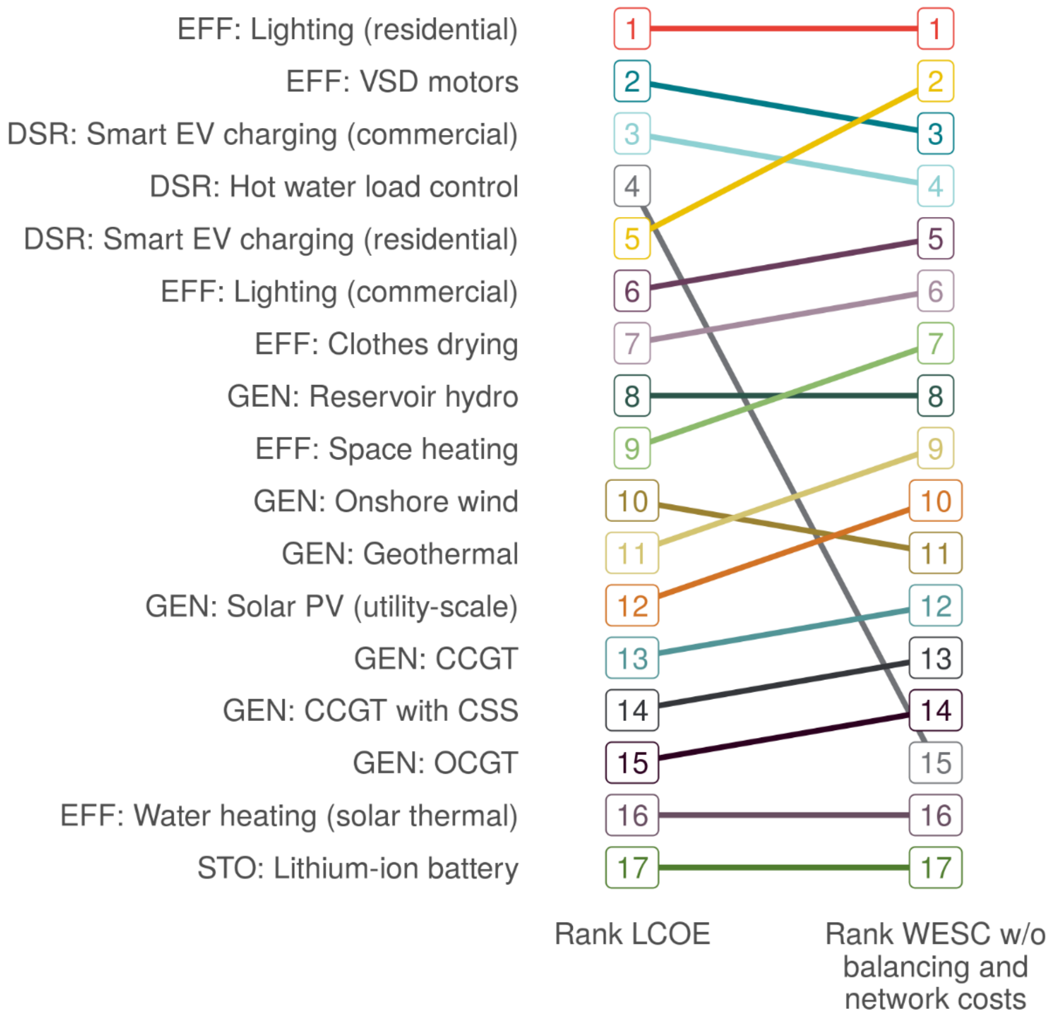
Figure 15 shows how the ordering of the technologies (from most to least beneficial to the system) changes when capacity adequacy and displaced generation impacts are included.

The most significant changes occur for the DSR technologies. The LCOE in Figure 11 does not include the cost of generators having to produce more during the periods where there is increased demand. This shows in Figure 14 as a reduced displaced generation benefit (which also affects the battery storage technology). The hot water load control technology has a particularly low displaced generation benefit. This is because, as described in section 4.3.1, even without DSR, immersion heaters are assumed to be on a timer set to turn on overnight when electricity is already cheap.

However, since EV-based DSR leads to a reduction in demand during the system peak and DSR technologies "produce" relatively little energy per MW, the EV-based DSR have significant capacity adequacy benefits. This is because we assume that EVs would be charged at the end of the working day without DSR – this coincides with the system peak. As we assume that water heating takes place in the early morning, hot water load DSR does not have any capacity adequacy benefits.

The ranking of space heating efficiency (air source heat pumps) improves. This is because space heat demand is closely correlated with overall demand. In other words, space heating efficiency technology is displacing relatively more expensive electricity.

Figure 15 Change in ranking of technologies based on WESC (without distribution network and balancing impacts) instead of LCOE

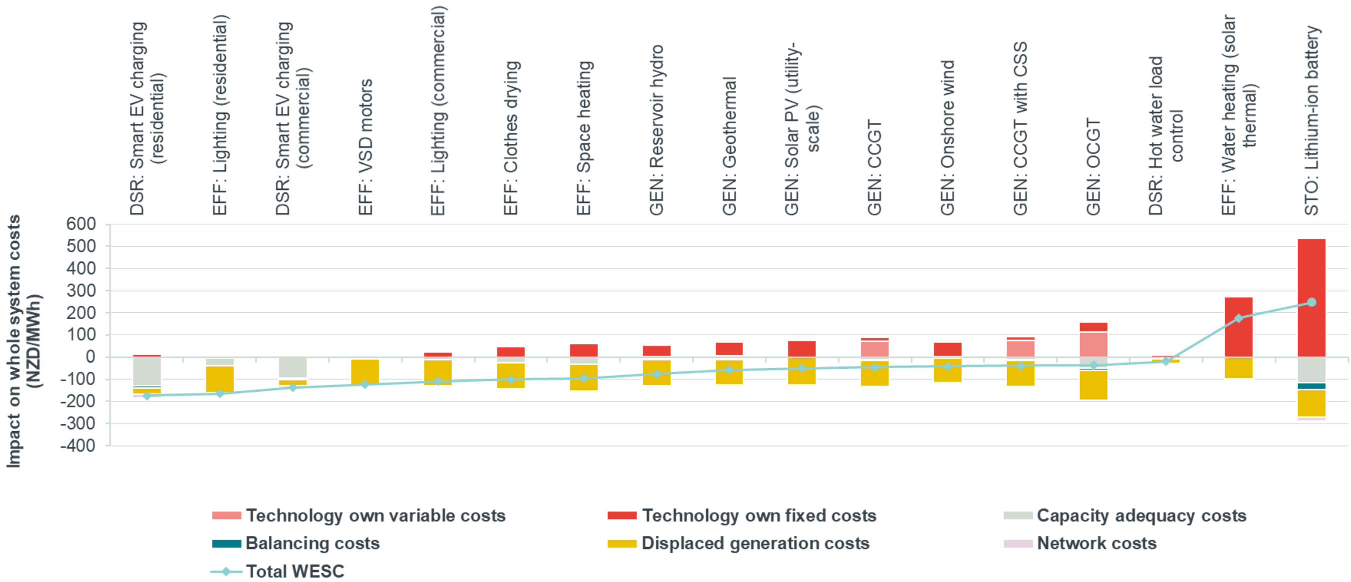


Source: Frontier Economics

In Figure 16 we add the balancing and distribution network components to our WESC estimate. Both of these components of WESC should be interpreted with some caution:

- As described in Section 3.6, the network impacts assume that the embedded technologies are located on a section of network that would otherwise require reinforcement.
- As noted in Section 3.4 the balancing costs are based on modelling carried out in the UK, and are therefore subject to particular uncertainty.

Figure 16 WESC estimates including balancing and distribution network impacts



Source: *Frontier Economics*

Note: *These illustrative figures should not be interpreted as "generic" estimates of the whole system impact of a class of technologies. Whole system impacts are dependent on the wider electricity system and when technologies are assumed to be built.*

The box below provides an example of how to interpret these figures.

WORKED EXAMPLE: RESIDENTIAL SMART EV CHARGING

Consider a residential electric vehicle which travels 40km per weekday, requiring 6kWh of electricity each time. The EV would usually be charged between around 17:30 and 19:30, using a 3.3kW connection. The installation of a smart charger could allow this charging to take place overnight, when electricity is cheapest and demand on the network is lowest. Every day, the smart charging reduces peak-time energy consumption by 6kWh – about 1.6MWh per year.

- We assume this requires a smart controller costing around $300. The controller is assumed to last for 30 years: Given the 5% discount rate we use, this corresponds to $19.5 per year. The **technology own fixed cost** is therefore $19.5 / 1.6MWh = $12/MWh
- We assume that there are no variable costs associated with carrying out DSR. The **technology own variable cost** is therefore $0/MWh.
- As the EV would otherwise be charged during the peak, it can reduce peak power consumption by 3.3kW. We assume that this is available with 75% reliability (so, across a fleet of EVs, about 2.5kW of power can be relied upon). Our model uses a cost of generation capacity of $82/kW (based on an OCGT's cost of new entry). The EV DSR can therefore save $82 x 2.5kW = $205 of capacity costs per year. Expressed per MWh of peak-time energy avoided, this **capacity adequacy benefit** is $205 / 1.6MWh = $128/MWh.
- The cost of reinforcing the distribution network is assumed to be $236 per kW. Deferring this reinforcement by a year, based on a discount rate of 5%, would be worth about $11. If the EV was on a portion of the network that may otherwise require reinforcement it might save $11 x 2.5kW = $28, giving a **network benefit** of $28 / 1.6MWh = $18/MWh.
- By shifting energy from the peak to the off-peak, the DSR means that more expensive generators can reduce their output, saving costs. This **displaced generation benefit** is $48 per EV per year, so $48 / 1.6MWh = $30/MWh.
- Finally, if the system operator can call on the DSR to address short-term imbalances in power supply and demand (for example briefly interrupting charging if there is insufficient generation on the system), this **can reduce the costs of balancing the system**. The indicative value of this benefit from our model is $16, so $16 / 1.6MWh = $10/MWh.

Therefore, in this illustrative example, the benefits to the system of this DSR far outweigh its costs: For every 1MWh of electricity released onto the system during the peak, the net benefits to the system are $174.

Adding the distribution network and balancing impacts to the WESC causes a small number of changes to the ranking of the technologies (shown in Figure 17):

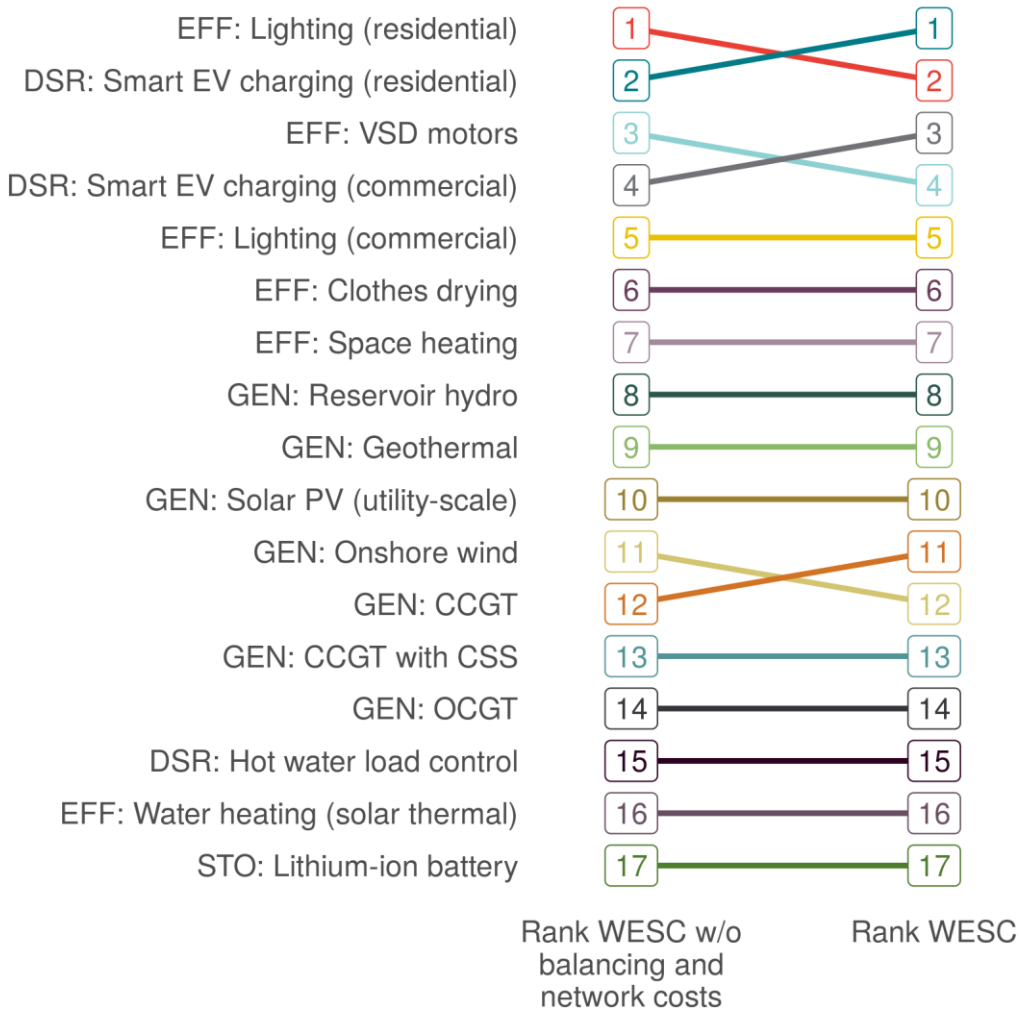
- Wind generation loses ground to the next most cost efficient technology. Wind, as an intermittent generator, is modelled as adding balancing costs to the system, and is assumed to not reduce costs on the distribution network. The technology that takes wind's place (CCGT) can provide balancing services.

- EV-based DSR technologies overtake the technologies ranked above them based on the WESC without balancing and distribution network impacts. This is because EV-based DSR technologies can provide balancing services unlike the technologies that they overtake (residential lighting efficiency and VSD motor efficiency technologies).

It is notable that the inclusion of network costs make less of a difference to the ordering of technologies than in our UK analysis. This is due to two factors:

- First, relative to the other elements (such as capacity adequacy costs) the distribution network reinforcement costs used in this modelling are lower than in the UK model.
- Second, some technologies in the UK model had an extremely low load factor (well below 1% for some forms of DSR). This will tend to magnify the whole system impact when expressed on a $/MWh basis. By contrast, the lowest load factor in this modelling is around 5% (for clothes drying).

Figure 17 Change in ranking of technologies based on WESC with distribution network and balancing impacts instead of without



Source: Frontier Economics

6 CONCLUSIONS

This report has presented estimates of illustrative WESC for demand-side and generation technologies in New Zealand. These estimates have been made at a high-level and are subject to significant uncertainties – more precise estimates could be produced from much more extensive analysis involving a full dispatch and investment model (which would also be required to incorporate effects such as "dry years"). However, they have allowed us to answer the two questions posed in Section 1.

First, **accounting for the wider impacts of technologies on the power system affects their value-for-money**. It is therefore important that comparisons between technologies are not made on the narrow basis of LCOE.

Second, **there are many demand-side measures which do have the potential to be more cost effective (on a MWh for MWh basis) than generation technologies)**. Energy efficiency technologies in particular may offer a particularly compelling alternative to baseload generation.

It is therefore important that policymakers consider demand-side technologies alongside generation technologies when considering the future trajectory of the power system:

- There is currently no collection of standard assumptions regarding the costs and benefits of demand-side technologies in the same way that MBIE collates information on the costs of generation technologies. Similar datasets covering the demand-side would make it easier for other analysis to include demand-side technologies alongside generation.
- It will also be important to assess whether all players in the market face incentives that accord with their wider impacts on the system. This does not just include investors in generation plants, but also individual consumers who are making decisions such as whether to install energy-efficient measures, or when to run their EV or heating system. The WESC metric can be used to determine whether this is the case.

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