Electric cars, solar panels, and batteries in New Zealand Vol 2: The benefits and costs to consumers and society



June 2016





This report may be quoted, or parts reproduced, provided Concept Consulting Group Ltd is cited as the source.

Concept Consulting Group Ltd

©Copyright 2016



What this report is about

The energy sector stands on the verge of a revolution. Advances in solar panels, electric vehicles and batteries are making these technologies much more affordable and accessible to consumers.

This report looks at the costs and benefits of these technologies, both for consumers, and society as a whole.

It addresses questions such as:

- Do electric vehicles make financial sense for consumers, and for New Zealand?
- What impact will solar panels have on a household's power bill, and the overall cost of electricity supply to New Zealand?

Suite of reports

This report is the second of three in a wider study looking at the broader impacts of new technology. An earlier report examined the likely impact on greenhouse gas emissions of these technologies – and is available here http://www.concept.co.nz/publications.html.

The third report will look at social impacts, and will address questions such as:

- Will uptake of these technologies affect parties other than the consumers who purchase them?
- Where technology uptake has positive or negative impacts on other parties, what if anything can be done to promote the ideal level of uptake?

The report on social issues will be released in the next couple of months.

Project support

Concept acknowledges the following organisations, who have made this study possible by providing financial support, data, or technical assistance.



This report has been prepared by Simon Coates, and David Rohan at Concept.

The opinions in this report are those of the authors, and do not necessarily reflect the views of organisations in the project support group.

Any errors or omissions are the responsibility of the authors.



Summary

Overview

Prices for electric vehicles (EVs), solar photovoltaic (PV) panels, and battery storage devices are falling rapidly. This report analyses the cost effectiveness of each technology based on recent price information.

We assess cost effectiveness from two different standpoints:

- For consumers we examine whether purchasing an EV, solar PV and/or battery will save them money relative to conventional alternatives, such as petrol-powered cars and grid-supplied electricity.
- For society we build on the consumer-level analysis, and also consider the impact of any hidden benefits or costs to society that are not currently being signalled to consumers.

Our analysis of EVs indicates their lifetime cost to the consumer is similar to conventional cars, and in some cases EVs are expected to save money over their lifetime.¹ However, EVs currently suffer from higher upfront costs than conventional vehicles and have lower ranges in the case of pure electric vehicles. Looking ahead, EVs are likely to become progressively more attractive as prices decline further, and range improves.

For society as a whole, we find that EVs offer some benefits that are not being signalled to consumers at present – from reduced tailpipe

emissions and electricity system benefits. On the other hand, EVs currently don't pay their full share toward roading costs, due to the road user charge (RUC) exemption.

These two sets of factors appear to broadly offset each other, thus nullifying the impact of the RUC exemption as an uptake incentive. Further, the RUC exemption is due to expire when EVs account for 2 percent of the light vehicle fleet. From that time, EV owners will effectively be penalised relative to their true costs if existing electricity and carbon pricing arrangements continue. In that situation, EV uptake is likely to be slower, relative to a situation where the full benefits and costs are signalled to consumers.² Our analysis suggests the cost to society from this slowing of EV uptake, and the resulting increase in public costs could be of the order of hundreds of millions of dollars including the cost of increased greenhouse emissions (among others)

Our analysis indicates that the cost-effectiveness³ of solar PV is very sensitive to each consumer's situation – being strongly affected by their level and pattern of power use, choice of panel size, and household location. We analysed an array of over 1,000 potential combinations of these factors. The analysis indicates that solar PVs are unlikely to provide consumer cost savings in most situations at present. However, under existing electricity tariff structures, PVs are likely to become increasingly attractive as panel prices decline further.

¹ In particular, plug-in hybrids travelling longer annual distances.

² Arguably, the reduced rate of uptake is already occurring because of the planned withdrawal of the RUC exemption.

³ This comparison focuses solely on financial benefits and costs. Some consumers may also gain non-monetary benefits from installing PV, but these are not quantifiable.

concept

For society as a whole, current arrangements generally create signals to install solar PV that are stronger than justified by solar PV's true benefits. In particular, existing electricity tariff structures typically make prices too high during summer and during the day, and not high enough in winter and in the evenings, when the costs of generation and electricity lines are at their highest.

This is likely to encourage sub-optimal decisions, such as installing solar PV in situations where it is not truly cost-effective, and/or discouraging the orientation of solar PV panels to capture winter energy which is more valuable. We estimate these misaligned signals could result in additional costs of approximately \$1.8bn over the next 20 years (even allowing for the ongoing cost reductions projected for solar PV panels).

Our analysis of batteries shows that they are unlikely to save consumers money based on existing prices. But battery prices are coming down, and they are expected to become attractive in some situations over time.

From the wider perspective of society, batteries offer the prospect of material benefits from avoiding the cost of providing generation and network capacity to meet brief periods of critical peak demand. This benefit is likely to be maximised if they are used to reduce network peaks. It is difficult to quantify this benefit, but it could run into the hundreds of millions of dollars or more.

However, current electricity tariff structures typically provide poor signals around the true costs of meeting peak demand, making it difficult to capture these benefits. Further, household batteries may not be the best energy storage option. Batteries in consumers' electric vehicles, using the 'vehicle-to-grid' injection technologies that are emerging with new EVs, may be a better option in the future.

Price signals are important

Capturing the full benefits from these new technologies will require smart choices about when, where and how to use them. And because uptake decisions will generally be consumer-driven, it is vital that consumers have access to clear and unbiased price signals. Our analysis shows work is needed to improve price signals.

In the case of CO_2 emissions, current CO_2 prices under the New Zealand Electricity Trading Scheme are much lower than the likely cost of CO_2 emissions to society.

In the case of electricity, it is not the general level of prices, but the *structure* of prices. As the following graph highlights, the prevailing flat-tariff pricing hides the fact that the cost of providing power varies significantly between summer and winter, and between evening peaks and other times.



Figure 1: Comparison between average flat tariff, and underlying incremental costs⁴ of meeting demand at different times



Poor electricity and CO_2 price signals are also likely to be slowing the uptake of other useful consumer technologies. These include: home insulation, wood burners, efficient lighting, and 'smart' appliances. As well as imposing an economic cost on society, this is likely to result

in New Zealand's greenhouse gas emissions being higher than they otherwise would be.

The balance of this summary discusses each new technology in more detail.

Electric vehicles - cost effectiveness for consumers

There are two main types of EV:

- Battery Electric Vehicles (BEVs) which are charged from the mains, and are entirely electrically powered
- Plug-in-Hybrid Electric Vehicles (PHEVs) which are charged from the grid, but also have a combustion engine to extend their range.⁵

EVs currently cost more to buy than their internal combustion engine (ICE) equivalents. This is due to the relatively high cost of batteries and, for PHEVs, the extra cost of having a combustion engine (and often a second drive train) as well as an electric motor.

Offsetting this higher up-front cost are lower running costs. EVs have lower fuel bills due to their inherently superior energy efficiency: electric motors are approximately four times more efficient at converting chemical energy into motive power (i.e. kinetic energy) than internal combustion engines.

⁴ Note: This graph only shows the *variable* costs incurred from increased electricity demand at different times. There are also some fixed costs of electricity supply which are not shown here, as these do not vary with increased kWh demand.

⁵ There are two sub-types to PHEVs. Those which have a second, petrol-driven drive-train powered by the combustion engine, and those which only have the

single drive train powered by the electric motor, but with a small combustion engine that is used solely to charge the battery and extend its range. This second type is typically referred to as an Extended Range Electric Vehicles (EREV). For the purposes of this study, EREVs have been grouped under the broader PHEV heading.



EVs also have much lower servicing costs. The lifetime servicing costs of BEVs are estimated to be less than 20% of equivalent ICEs. Electric drive trains are simpler than combustion engine drive trains, with lower wear-and-tear.

Figure 2 shows that this balance of high up-front costs versus lower running costs mean that EVs are already starting to become economic for consumers who drive longer distances.⁶,⁷



Figure 2: Lifetime cost of vehicles (at 10 & 20 kVKT)⁸

With projected significant further falls in battery costs and manufacturing scale economies, this lifetime cost equation is likely to increasingly tip in favour of EVs, increasing the savings for vehicles with higher VKT and becoming economic for owners of vehicles with lower VKT.

Electric vehicles - cost effectiveness for New Zealand

While Figure 2 shows the consumer cost-benefit, it hides the fact that there are significant misalignments between the 'private' costs consumers see, versus the underlying 'public' costs of EVs and ICEs to New Zealand as a whole. We have identified four areas where significant price misalignments occur relative to the true level of costs:

- Three areas where EVs are likely to be penalised relative to ICEs:
 - The electricity cost from charging EVs at off peak times (e.g. overnight) generally being too high;
 - The payments which future EVs could earn from injecting power back into the electricity grid at times of peak demand being too low;
 - The CO₂ price that ICE owners pay from tailpipe emissions being too low.⁹

⁶ This can also be seen overseas where electric vehicles are becoming prevalent in urban taxi fleets which have higher daily travel distances and are sensitive to fuel costs.

⁷ Costs incurred in future years have been discounted at a real rate of 6% to allow for the time value of money.

⁸ kVKT = thousands of vehicle kilometres travelled. 10 kVKT = 10,000 km/yr.

⁹ ICEs also have other environmental costs relative to EVs which are not being correctly reflected into pricing decisions, and which damage human health / welfare. These include higher particulate emissions and noise relative to EVs. However, we have not been able to reliably quantify the scale of costs associated with such factors.



- One area where EVs are currently receiving an advantage relative to ICEs¹⁰:
 - avoiding paying the same roading charges (collected via petrol excise and (for diesel vehicles) Road User Charges) used to fund the road infrastructure.

In relation to electricity pricing, as discussed in Chapter 2, current arrangements are not effective at signaling the true cost of electricity. EVs charged at off-peak times will typically pay too much for power, and be under-rewarded for the value of power injected into the grid at critical peak times.

With respect to CO_2 emissions, as discussed in section 3.3.3, the effective CO_2 price incorporated into petrol and diesel costs is currently around NZ\$5/tCO₂ – which translates to 1 cent/litre. However, the true cost is expected to be much higher. We have adopted a mid-point estimate of \$50/tCO₂¹¹, but also considered other sensitivity cases.

In terms of roading charges, BEVs currently pay no charge, whereas we have estimated that PHEVs pay roughly 12% of the amount paid by ICEs since they consume proportionately less petrol. This effectively means that EVs receive a concession, relative to ICE vehicles.¹² The BEV exemption is due to be removed when EVs reach

two percent of the light vehicle fleet, and changes for PHEVs may be made at the same time.

Figure 3 presents the estimate of the net impact of these different factors on the average annual cost of driving a vehicle for 15,000 km/year.¹³ The chart shows low, medium and high estimates, because some factors vary by circumstance (e.g. electricity tariffs in some areas are closer to the 'true' costs for night-time electricity) and some factors are subject to inherent uncertainty (e.g. the 'true' cost of carbon emissions to society).

¹⁰ This ignores any existing distortions in the current Road User charges such as more efficient petrol vehicles paying materially less excise compared to the RUC levied on an efficient diesel or EV.

¹¹ This is based on the Business Energy Council's Waka scenario. We have also considered sensitivity cases with lower and higher carbon prices.

¹² This assumes that petrol excise is used solely to fund road infrastructure costs, and does not address any differences in environmental costs between EVs and ICE vehicles, and that EVs and ICEs give rise to the same average infrastructure cost on a per vehicle basis.

¹³ 15,000 km was chosen as a representative range of the distances travelled by drivers who first purchase vehicles that are imported into New Zealand.



Figure 3: Summary of current price misalignments for a 15,000 km/year vehicle



While the current roading charge concession potentially more than counter-balances the other factors that penalise EVs¹⁴, once that is removed, our medium estimate is that EVs will be penalised by approximately \$600/year for PHEVs and \$930/year for BEVs.

These ongoing pricing misalignments are expected to slow the uptake of EVs relative to optimal levels, with two main negative outcomes for New Zealand:

- New Zealand spending more on transport than it should (largely in the form of imported fuel, rather than New Zealand-generated electricity)
- materially greater CO₂ emissions.

Overall, we estimate the associated economic costs to be between \$300m and \$700m. The large range reflects inherent uncertainty in factors such as the scale of some of the price misalignments, and the pace of international development in EVs.

Solar PV – cost effectiveness for consumers

From a consumer's perspective the cost of solar PV is largely the upfront purchase and installation cost¹⁵. These costs vary according to panel size. The monetary benefits of solar PV come from two value streams:¹⁶

- avoiding paying the variable electricity tariff when the panel is generating and reducing the household's grid-supplied power (self-consumption)
- earning 'export' revenue payments for periods when the panel is generating more than household demand.

¹⁴ This ignores any distortions that may exist between Road User Charges and Petrol Excise Duty.

¹⁵ The graph also shows two additional costs: replacing the inverter roughly halfway through the panel's life, and 'maintenance costs': being regular cleaning to wash dirt off the panels.

¹⁶ Consumers may also value non-monetary benefits, such as a preference to generate more of their own power. It is not possible to reliably estimate such non-monetary benefits, and they have not been included in this analysis.



• 6 kW

• 4 kW

• 2 kW

The overall amount of electricity produced by a solar PV installation is affected by the panel size and household location, among other factors. The export proportion is also influenced by panel size, as well as the level and pattern of household power use.

To analyse the net impact of all of these factors, we modelled approximately 1,000 different combinations of consumer situation (usage level and patterns) and PV panel sizes, using two years of hourly sunshine and temperature data for three different locations.

Figure 4 shows the estimated proportion of PV output that would be exported for different combinations of consumer situation and panel size. It indicates that there is considerable variation in export proportion, and that even for households with higher than average power consumption and smaller 2 kW panels, some export is likely.



....

• !

٠.,

18,000 10,000 12,000 14,000 16,000 20,000 22,000 Gross consumer demand (kWh/yr) erTech_v15.xlsm To analyse the potential financial attractiveness of installing solar PV, the data for ~1,000 situations was evaluated against a range of retail electricity prices that consumers face across the country. The resulting estimated distribution of the financial attractiveness of solar PV to the modelled household situations is shown in Figure 5.

The chart shows a wide range of potential financial outcomes, with relatively few situations yielding a positive net benefit. The wide spread arises because the financial outcome from installing solar PV

100%

90%

80%

70%

60%

50%

40%

30%

20%

10%

0%

0

2,000

4,000

6,000

8,000

Proportion of PV exported (%)

¹⁷ We do not have detailed information on the extent to which solar consumers are sizing their panels to match their individual level and patterns of consumption. We have modelled what we understand to be typical consumption patterns, and a range of different solar panel sizes and consumption levels. For reference,

Electricity Authority data indicates that the average residential solar PV installed capacity is approximately 3.5 kW, and MBIE data indicates that the average household electricity consumption is approximately 7,300 kWh/yr.



is strongly influenced by each household's power consumption level and pattern, the panel size, and the home's location.

Figure 5: Modelled variation in current consumer net present value (NPV) of solar PV



It is important to note that Figure 5 shows the estimated distribution of outcomes for the ~1,000 modelled household situations *if* they installed solar PV. It does not provide information about the distribution of outcomes for households that *have* actually installed solar PV.

The reason for this is that households for whom the financial attractiveness of solar PV is relatively higher (i.e. those in the righthand 'tail' of the distribution) would be more likely to be early adopters, all other things being equal. So for example, early adopters are more likely to reside in sunnier regions, have lower export proportions because they use power throughout the day, and have sought to optimise the panel size to their power usage etc.

Looking ahead, we expect panel costs to continue to fall at significant rates, due to ongoing technological improvement. Efficiencies are also expected in installation costs, as has been achieved in Australia.

Based on our central cost-reduction assumptions¹⁸, Figure 6 shows how the distribution of net present values would change from the 2016 distribution (shown in Figure 5) for the ~1,000 modelled situations over the next 10-20 years, assuming that retail tariff structures continue unchanged.

¹⁸ Our central projections are for panel prices to fall at 7% per annum, inverter prices to fall at 3% per annum, and installation costs to fall at 3.5% per annum.



Figure 6: Change in consumer NPV of solar investment



This analysis indicates that solar PV would become cost effective for around 40% of the modelled household situations within 10 years. And in 20 years' time solar PV would be cost effective for most of the modelled household situations¹⁹ – if retail tariff structures continue unchanged.

Solar PV - cost effectiveness for New Zealand

The previous section discussed solar PV benefits from a consumer perspective. However, under current arrangements, there are significant misalignments between the 'private' benefits that are signalled to consumers, versus the underlying 'public' benefits of solar PV to New Zealand as a whole. The main source of the difference is the structure of retail electricity tariffs.²⁰

The left-hand portion of Figure 7 shows the reward signalled to consumers for installing PV. It shows the variable residential tariff avoided via self-consumption of PV-generated power,²¹ and the export tariff for PV output that is not self-consumed.

In both cases, the average level of reward to the consumer is indicated by the circle at the top of the bar. Because there is some variation across the country in tariffs, the high and low values are indicated by dashes.²²

¹⁹ It is likely that a significant proportion of houses will not have roofs which are suitable for solar PV, plus rental properties may also be less likely to have solar PV installed. These factors may mean that the above proportions need to be multiplied by approximately 2/3 to arrive at estimates of households for whom solar is likely to be financially attractive.

²⁰ Unlike EVs, the distortion in carbon prices does not have a major impact on solar PV, because our analysis indicates solar PV is effectively a substitute for other low emission generation technologies, such as geothermal and wind generation, rather than fossil-fueled generation. For a fuller explanation, see:

www.concept.co.nz/uploads/2/5/5/4/25542442/new technologies emissions r eport final.pdf

 $^{^{\}rm 21}\,$ Which may be based on a standard or low-user variable rate, depending on circumstances.

²² The High / Low variation in tariffs is due to factors such as whether consumers have a one or two-meter configuration for billing for hot water, whether the network and/or retail company is relatively higher or lower cost, and whether the network and/or retail company has chosen to recover a greater proportion of their costs from fixed versus variable charges.



The right-hand portion of the chart shows the estimated true value that solar PV provides to society as a whole in terms of avoided costs of grid-supplied power. Figure 7 indicates that:

- the reward for self-generation is significantly higher than the actual value of PV-generated power
- the reward for PV export is broadly similar to the actual value of PV-generated power.

Figure 7: Consumer reward for installing solar PV versus benefit to society



The key reason for this difference is that the variable residential tariff contributes to recovery of three main cost components: grid

generation, network, and retail operating costs (metering, billing, etc.). By using solar PV to reduce their demand, solar-owning consumers reduce their contributions to all of these cost components. This would be appropriate if self-consumption of PV-power actually reduced these costs.

However, as the 'value of solar' column highlights, only the generation component of costs is expected to be reduced.²³ Solar PV generation does not materially reduce network or retail operating costs.²⁴ This may seem surprising at first sight, but:

- a high proportion of electricity network costs are driven by the capacity needed to meet peak demand periods. In New Zealand, these are generally on cold winter evenings – when solar PV makes little or no contribution to supply.
- retail operating costs don't change much with a customer's level of consumption. Instead, they tend to be related to customer specific issues, such as whether bills are paper-based or online, the degree of complexity in the metering setup, etc.

Because customers with solar PV will make lower contributions to recovery of network and retail operation costs under current pricing arrangements, ultimately these costs are likely to be shifted toward non-solar PV owning consumers. The potential social consequences of such cost-shifting will be addressed in the third report in this study.

²³ As discussed in section 4.4.3, as solar PV uptake increases, this will tend to reduce the size of the benefit from displaced grid generation. As a result, the value of additional solar is likely to decline at higher levels of uptake, all other factors being equal.

²⁴ Indeed, analysis indicates that solar PV is likely to slightly increase both retail and network costs.



The assessment of the value of solar PV across the ~1,000 different consumer situations was repeated, but this time based on the estimated true value of solar PV to New Zealand. The results were then compared to the private benefits shown earlier.

*Figure 8: Comparison of distribution of private and public net present values of solar PV across different consumer situations*²⁵



The combined public and private analysis is shown in Figure 8. It indicates that:

• Assuming consumer decisions are based on existing electricity tariff structures, uptake of PV is likely to grow strongly over the

next decade, because consumers will see increasing financial rewards from installing PV.

• But based on underlying true benefits, much of the PV uptake is likely to be inefficient.

We estimate that the misaligned signals in existing electricity tariffs could encourage inefficient PV uptake costs of approximately \$1.8bn over the next 20 years. This compares with the estimate of costs compiled by NZIER, which was \$2.7bn to \$5.0bn dollars (present value).²⁶

Figure 9 illustrates why the costs are likely to be significant. It shows the annualised cost of power on a like-for-like basis (to the extent possible) of four potential new generation options for New Zealand: three grid-scale technologies²⁷ (wind, geothermal, and combined-cycle-gas turbines), and solar PV (split between residential-scale 'rooftop solar' and large-scale 'utility solar'). Each is assessed solely on the <u>relative differences</u> in the cost of producing electricity delivered to the point of consumption (including the emissions impacts captured via carbon charges).

Because none of the technologies are expected to avoid or reduce the need for transmission and distribution to be built, there is no difference ascribed to network costs. However, rooftop solar PV does have the benefit (albeit very small) of avoiding losses incurred from transporting electricity across such networks.

²⁵ The three 'spikes' to the distribution public evaluations are because this analysis only considered three sizes of PV panel: 2kW, 4kW and 6kW. These pubic benefit distributions take no account of the progressive reduction in the avoided grid generation value of solar with progressively higher levels of solar penetration.

²⁶ "Effects of distribution charges on household investment in solar", NZIER report to the Electricity Authority, 30 September 2015

²⁷ Hydro is not included in this comparison because there are not many significant new hydro schemes that are likely to be able to receive environmental consents.



0.25 Assumptions: CO2 = Gas = \$6.0/GJ \$150/tCO2 0.20 CO2 = \$50/tCO2 LCOE (\$/kWh, excl. GST) CO2 = \$5/tCO2 0.15 Network losses 0.10 Fuel 0.05 VOM 0.00 FOM Roottopsolat Geothermal Utility solar تى Nind Capital ConsumerTech v17.xlsm

*Figure 9: Current generation, and relative transport cost implications, for new generation technologies*²⁸

Figure 9 shows the direct costs of such technologies (capital & operating costs, fuel, and CO₂) for electricity generated and delivered to a point of consumption. However, it ignores likely wider system costs which are likely to progressively increase for high levels of penetration for some technologies:

• backup generation for periods when the generator may not be operating, for less firm generation such as PV and wind

• distribution network reinforcement costs to cope with reverse power flows with high levels of solar PV.

Figure 9 shows that rooftop solar PV is currently approximately \$0.125/kWh more expensive than wind and geothermal. When this \$0.125/kWh is multiplied by the generation from a typical 4kW solar panel over a 20-year life, this results in a present value cost of approximately \$7,150 per panel. This \$7,150 represents a cost to New Zealand from a sub-optimal technology choice – building a 4kW solar panel, when we could have supplied that power more cheaply over the grid from renewables such as wind and geothermal.

If this \$7,150 is multiplied by the estimated number of households for whom solar PV could be attractive by 2026 based on current tariff structures and PV cost-reduction rates (estimated to be 1/4 of all households), this gives a total cost of \$3.0bn.

This is larger than the \$1.8bn noted above because the more detailed modelling exercise takes account of projected future reductions in the cost of solar PV, whereas this illustrative calculation has not. Nonetheless, it is a similar order of magnitude and illustrates how New Zealand may incur significant costs by encouraging consumers to make inefficient technology choices.

The economies of scale of utility-solar result in it being significantly cheaper than rooftop solar. However, because it is currently more expensive than wind and geothermal, it is not being developed, because the potential utility developers of such solar projects do not

²⁸ The levelised cost of energy (LCOE) captures all costs to produce electricity (capital and operating), and spreads them evenly over the expected annual kWh of generation for each technology to give a \$/kWh measure. This allows like-for-

like comparisons. FOM = Fixed operating & maintenance, VOM = Variable operating & maintenance.



face the same distorted price signals that consumers can take advantage of for rooftop solar PV.

Solar in remote rural situations

One area where PV may offer net economic benefits is in some offgrid applications. For example, for some rural customers, it may be lower cost to implement off-grid solutions using local generation such as PV when existing lines serving few connections need an upgrade or replacement.

However, again, these benefits are unlikely to be fully realised under current electricity price structures.

Batteries and other storage technologies

The principal benefits of battery storage²⁹ are the avoided costs of providing infrequently-used generation and network capacity to meet the 1-2% of periods that currently make up the critical peak system demand. Although the costs of battery storage are currently greater than this benefit, further reductions in the cost of batteries could bring them to the point where they deliver positive netbenefits – particularly in situations where peaking capacity costs are significant.³⁰ However, even if such battery cost reductions resulted in batteries being economic from a New Zealand perspective, the economics of storage-only (i.e. not in conjunction with solar PV) from a consumer's perspective wouldn't stack up based on most current tariff structures. This is because a flat all-day tariff wouldn't provide a peak/off-peak differential signal to make battery use financially attractive. Even where day/night or day/night/peak tariffs are currently offered, the differentials don't appear to be at levels which reflect the true scale of cost-saving that could be achieved from such within-day load shifting.

A move to more cost-reflective tariff structures (e.g. time-of-use and/or other peak demand pricing approaches) could help change this situation, and make batteries start to become economic from a consumer's perspective.

With future enhancements in inverter technology, customer owned batteries will also enable customers to provide security of supply (while their storage lasts) for their own use when the network is down. This may be a benefit to customers who experience frequent interruptions (e.g. some rural users), but it is not expected to be a material benefit for urban customers where outages are typically fewer (and shorter).

²⁹ Hot water cylinders are not considered as a stand-alone storage technology in this section as they are a mature technology.

³⁰ There is significant variation in the range of potential avoided peak capacity costs. This is due to a variety of factors including:

¹⁾ Uncertainty of the Long Run Marginal Cost of network capacity investment to meet peak demand growth. This is due to relatively little analysis having been undertaken of this matter in New Zealand. Australian LRMC estimates using an Australian regulatory-prescribed methodology are significantly higher than the

few estimates found in New Zealand (noting that such estimates are not generally on a like-for-like basis).

²⁾ Variation in the extent of spare capacity on different New Zealand networks (spatially and over time).

³⁾ Uncertainty over the extent to which New Zealand's current situation of surplus generation capacity will persist or reverse, though changes relating to the potential retirement of the Huntly Rankine units, loss of major sources of demand such as the Tiwai aluminium smelter, or other generation or demand changes.



However, even where there are significant day-night electricity price differences and/or reliability benefits, it is not clear that household batteries would be the best solution for New Zealand for a number of reasons.

Firstly, there appear to be economies of scale with batteries, and a few larger, utility-owned batteries located at strategic points around a distribution network could deliver exactly the same (if not slightly more) electricity system benefits³¹ as would be achieved from having large numbers of smaller consumer batteries – but at lower cost. This is illustrated in Figure 10 below, which also indicates the wide range of battery costs and benefits.

Even more importantly, targeted distributor battery installation in areas of constraint (as opposed to wide scale customer deployment including unconstrained areas) will ensure that an immediate economic benefit will be achieved. This demonstrates that although pricing with a LRMC approach would be more cost reflective than the current arrangements, it does potentially suffer from signalling to customers in unconstrained areas that investment in technologies to avoid peak is more useful than it really is at the current time. A balanced approach is required to ensure that some form of long term price signal is used to encourage useful long term changes in customer behaviour and investment but not drive large scale unnecessary customer investment in areas where the network is unconstrained.

1,600

Figure 10: Projected societal cost-benefit of batteries

1,200 \$/kWh storage 800 800 400 200 0 Cost Value Cost Value Cost Value Cost Value Current Future Current Future **Residential battery** Utility battery ConsumerTech v16.xlsm

Secondly, utility-scale batteries may themselves be more expensive than an even-cheaper alternative – namely the batteries in electric vehicles (EVs). These too have the potential to inject power back into the grid at times of peak demand. However, the *incremental* cost of such batteries could be much lower than static household or utility-scale batteries. This is because EV batteries would largely already be being paid for to provide another service – i.e. transport.

We have also considered the combination of batteries and solar PV. The relative attractiveness of solar to consumers based on current

³¹ This is due to multiple effects such as load diversity (which means that a smaller utility battery is required compared to distributed consumer batteries), that the utility will seek to reduce real costs (i.e. not simply minimise consumer costs), and

there is the ability to relocate utility batteries over time to parts of the network with greatest need.



tariff structures is strongly influenced by their consumption patterns and, by extension, the amounts of solar power they export or selfconsume.

If consumers could more readily store 'surplus' solar power, and use it later when their demand exceeds their solar generation, a greater proportion of their PV output would be rewarded at the variable residential tariff.

Two main storage technologies are available to enable solar-PVowning consumers to capture this benefit:

- Lithium-ion batteries (e.g. the Tesla Powerwall, Panasonic home battery etc). The current cost of a household-scale battery with an 8 kWh storage capacity is approximately \$9,400 (including installation and GST).
- Hot water cylinders, which 'store' excess solar electricity in the form of hot water, reducing the need to heat the water later at peak demand times. If a house has an existing hot water cylinder, the only cost is a diverter – estimated to cost ~\$900 incl. GST. If a new hot water cylinder is required, this can add an additional \$2,300.

Figure 11 shows the estimated impact of storage on the cost effectiveness of solar PV for households with a 4kW panel. It indicates that the upfront cost of a lithium-ion battery outweighs the financial benefits from increasing self-consumption of PV output – making the overall impact worse than for a PV-only household.

However, hot water cylinder storage improves the cost effectiveness of solar PV from a consumer perspective – but still not to the point of delivering an overall net benefit for an average household with a 4 kW solar panel.

Figure 11: Current financial benefit of storage for 4kW solar PV owning households³²



While solar + storage does not appear cost-effective for the majority of consumers at present, cost-reductions in both technologies raise the potential for solar + storage to become increasingly attractive to consumers.

³² Although the impact on the altered proportion of export is roughly the same for batteries and hot water storage, the value is different due to the fact that in many network areas, hot water is charged on a specific hot water tariff.



In principle, consumers with solar + storage could reduce their grid demand during winter evening peak periods, by using stored PV energy that was generated earlier in the day. If PV + storage was used in this way, the reduction in network costs over time would be a potentially important public benefit.³³

To test the potential for this effect, we analysed the data on the ~1,000 consumer situations discussed earlier, to examine how PV + storage affects peak demand and network requirements. The analysis indicated that storage technologies were only operating at 20% of their capacity on average during winter peak periods. In many cases, this was due to sustained cloudy weather resulting in insufficient solar power to fill up the storage during the day, for later release during the peak periods.

If during these cloudy days, the storage was topped-up from off-peak power purchased from the grid, the modelling indicated these solar + storage customers would achieve greater demand reductions (and network savings) at peak times.

However, this points to a deeper truth: it is not solar + storage that is enabling system cost savings – it is the <u>storage alone</u> through its ability to store power at times of surplus to be released at times of relative scarcity.

Operating storage technologies in combination with solar does not make the storage technology more effective. Indeed, if a solar consumer is incentivised to operate storage to reflect their own needs, the resulting storage operating profile is expected to be <u>less</u> effective at minimising New Zealand's system costs:

- Instead of filling up the storage at times of greatest whole-ofsystem surplus (e.g. overnight when the ratio of NZ's renewable supply to grid demand is highest), a significant amount of storage will be filled up during the middle of the day at times of peak solar output.
- Although most consumers' demand tends to follow that of the whole system, there is significant individual variation. Storage operated to offset each individual consumer's peak demand profile will, across the wide variety of consumers, be less effective at reducing system peaks than if batteries were operated to minimise New Zealand's overall system peaks.

Taken together, these effects mean that storage operated to reflect individual customers' needs won't deliver as much benefit as an approach which operated storage based on when New Zealand as a whole had greatest renewables surplus and scarcity.

³³ While storage technologies are expected to reduce network costs, they are not expected to reduce retail operating costs.



Contents

Summaryii			
l Purpose1			
1.1 What the broader study is about1			
1.2 What this specific report is about1			
2 Setting the scene – the importance of electricity tariffs for consumers' choices			
3 Electric vehicles5			
3.1 Introduction5			
3.2 Electric vehicles – cost effectiveness for consumers5			
3.3 Electric vehicles – cost effectiveness for New Zealand7			
3.3.1 Electricity charging costs for EVs being too high8			
3.3.2 Potential payments for injecting back into the grid being too low12			
3.3.3 Pollution costs levied on ICE owners being too low 14			
3.3.4 EVs avoiding paying for the road transport network 15			
3.3.5 Summary of misalignments to EV economics17			
3.4 Overall economic impact of current pricing misalignments17	5		
4 Solar photovoltaics (PV)19			
4.1 Introduction19			
4.2 Solar PV – cost effectiveness for consumers20			
4.2.1 Possible future reductions in the cost of solar PV23			

4.2.2	The cost of commercial and utility-scale PV2		
4.3 Val	ue of PV generation to consumers25		
4.3.1	Variation in the tariff that can be earned by solar PV 26		
4.3.2 demano	Variation in the balance between a consumer's and solar PV generation28		
4.3.3 and PV	Uncertainty over future changes to electricity demand export tariffs		
4.3.4 consum	Overall evaluation of likely cost-benefit of solar PV to ers		
4.4 Sol	ar PV – cost effectiveness for New Zealand35		
4.4.1	Avoided retail costs due to solar PV37		
4.4.2	Avoided network costs due to solar PV38		
4.4.3	Avoided energy costs of solar PV		
4.4.4	Avoided CO ₂ costs due to solar PV42		
4.4.5	Total value of solar PV44		
4.5 Est New Zeala	imating the overall cost-benefit of solar PV uptake for and46		
5 Batterie	es and other storage technologies52		
5.1 Bat	tery storage – cost-effectiveness52		
5.1.1	The costs of batteries52		
5.1.2	Value of batteries53		
5.1.3	Summary cost-benefit of batteries56		
5.2 Sto	rage + PV solar – cost effectiveness for consumers 58		



5.3	Stora	ge + PV solar – cost effectiveness for New Zealand .6	51
Append	ix A.	Background information on vehicles6	54
Trave	l pattei	rns6	54
BEV r	ange ar	nxiety6	55
EV ch	arging	patterns6	55
Append penetra	ix B. tion lev	Analysis of the generation value of solar at hig vels6	gh 57
Append	ix C.	Analysis of network costs7	'1



1 Purpose

1.1 What the broader study is about

Electric vehicles (EVs), solar photovoltaic (PV) panels, and batteries offer the promise of cheaper, cleaner energy and transport.

However, these technologies of "tomorrow" are emerging within "yesterday's" industry arrangements – particularly with respect to how electricity is priced to end consumers. Coupled with potential under-pricing of CO_2 emissions, current arrangements may lead to undesirable outcomes in three key areas:

- Undue CO₂ emissions
- Increased energy and transport costs
- Poor social outcomes.

Each of these issues³⁴ is examined in one of three separate reports which make up this overall study.

This report is the second in the series, and examines the economics of these new technologies, particularly whether they are likely to be least-cost options for New Zealand.

The first report³⁵ examined the emissions consequences of the uptake of these different technologies.

The third report will examine the potential adverse social consequences of new technology uptake³⁶, including the potential flow-on effects from revised tariff structures that are intended to deliver better environmental and economic outcomes.

1.2 What this specific report is about

This report analyses in detail the economic implications of new technologies. In particular, it assesses whether they are likely to be value for money, and whether current electricity pricing arrangements are likely to deliver the best outcomes for New Zealand.

For each technology, we examine:

- What are the direct costs of the technology? i.e. up-front capital & installation costs, and ongoing maintenance costs.
- What is the current 'private' value *to the consumer* from the operation of the technology based on current electricity and fuel prices?
 - What is the financial reward for a consumer from a rooftop PV panel, based on current electricity tariff structures?
 - What is the financial reward to an electric vehicle-owner of avoided petrol costs less the electricity costs of charging the battery?

³⁴ The issues identified in this report may also apply to some other consumer energy technologies - e.g. space heating options (wood vs electric vs gas), home insulation, efficient lighting. These are not addressed specifically in this study, as it focuses on new consumer energy technologies.

³⁵ The report can be downloaded here:

http://www.concept.co.nz/uploads/2/5/5/4/25542442/new_technologies_emiss ions_report_final.pdf

³⁶ Poor social outcomes are not just from higher national energy bills generally, but additionally from aspects such as PV-owning consumers 'shifting' costs onto other consumers.



- What is the 'public' value to New Zealand from these technologies

 i.e. what energy and transport-sector costs are reduced / caused
 by the technology and how might this differ to the private value
 to the consumer?
 - What electricity sector costs (generation, network, retail) are actually avoided from rooftop PV generation, and what costs may be increased by PV generation? And how does this compare with the benefit solar-PV-owning consumers see based on their current tariffs?
 - What electricity sector costs arise from charging an EV battery at different times of the day and year, and how do these costs compare with the prices consumers are currently paying?
- If the 'private' benefit to consumers is different to the 'public' benefit to New Zealand, what is the likely scale of economic cost arising from:
 - too little uptake of technologies whose costs to New Zealand are lower than the value which consumers can currently realise; and
 - too much uptake of technologies whose value to consumers based on current electricity tariffs exceeds the value to New Zealand.

As well as considering each of the technologies separately, we have considered whether *combinations* of technologies (e.g. PV plus home batteries) will alter the outcomes.

In addition, although the principal focus is on household-scale technologies, for solar-PV and batteries, we have examined whether larger-scale implementations of these technologies may be more or less economic.³⁷

Lastly, much attention has been given overseas to the implications of these new technologies for existing utilities – both grid-scale generators, and transmission and distribution network companies. This is also currently being considered by the Commerce Commission in New Zealand in its review of the economic regulatory regime for network companies.

for batteries: utility-scale versions which are hundreds of times larger than household-scale versions.

³⁷ i.e. for PV panels: either warehouse-rooftop implementations or even larger utility-scale solar PV 'farms'; and



2 Setting the scene – the importance of electricity tariffs for consumers' choices

Electricity pricing structures have remained largely unchanged for almost a century – being based typically on a daily fixed charge (\$/day), and a 'flat' consumption charge (\$/kWh).³⁸ While this price structure is relatively simple, it is not very effective at signalling the true cost of supplying electricity - which can vary significantly at different times of day and year.

For example, there is generally more than enough renewable electricity (hydro, geothermal and wind) to meet night-time demand, and so night-time generation costs are typically very low. However, on cold winter evenings costs can be much higher when infrequently-used fossil-fuelled generators are needed to meet peak demand periods.

Demand during peak periods also strongly influences transmission and distribution network costs. This is because a large proportion of such costs are associated with building sufficient capacity to meet periods of peak demand. Because other network costs are largely fixed, or driven by factors other than the volume of electricity flowing along the wires, increased demand outside of peak periods will not result in any material increase in network costs. As Figure 12 below shows, having a flat tariff means that consumers are typically paying much less than it costs for consuming electricity during winter peak times, and more than it costs for other times.

*Figure 12: Illustrative comparison between current flat tariff and true cost of power at different times*³⁹



These pricing misalignments can bias consumers' technology choices – encouraging over-use of some higher cost technology options, and

supply which are not shown here, as these do not vary with increased kWh demand.

³⁸ As discussed later, the electricity tariffs offered by some suppliers are more 'granular', with charges that vary by time of day, or season etc.

³⁹ Note: This graph only shows the *variable* costs incurred from increased electricity demand at different times. There are also some fixed costs of electricity



holding back uptake of some technology options with lower overall costs.

In particular, under current arrangements, we expect:

- There will be over-investment in technologies that use power at times of peak demand (e.g. electric fan heaters), and underinvestment in options that don't add to peak demand (e.g. wood burners or gas fires, home insulation, efficient lighting, 'smart' appliances). This is expected to encourage higher peak network and generation costs than is ideal.
- There will be under-investment in technologies whose consumption is dominated by off-peak demand, such as electric vehicles that are charged overnight. This will result in relative under-utilisation of such technologies, and increased costs for substitutes, such as fuel costs for imported petrol.
- There will be under-investment in technologies (e.g. batteries and home energy management systems) that use off peak power to avoid using peak power.
- Lastly, appliances which *inject electricity* (e.g. PVs) will tend to earn too little from providing electricity in winter peak periods, and too much at other times. This is likely to result in technologies that generate predominantly outside of winter peak periods being paid too much, and will encourage technology choices that are more expensive than the 'grid'.

In the next three chapters, we explore these issues in more detail, looking at electric vehicles, solar PV and storage technologies such as household batteries.



3 Electric vehicles

3.1 Introduction

Although battery-powered vehicles have been around since the early 20th Century, it is only in the last decade that significant advances in battery technology have reached the point where the costs of storing electrical energy to power an electrical motor is approaching that of storing chemical energy (i.e. petrol) to power a combustion engine.

There are two main types of EV:

- Battery Electric Vehicles (BEVs) which are entirely electrically powered
- Plug-in-Hybrid Electric Vehicles (PHEVs) which also have a combustion engine to extend the range of the vehicle beyond that of the battery. There are two sub-types to PHEVs.
 - Those which have a second, petrol-driven drive-train powered by the combustion engine; and
 - Those which only have the single drive train powered by the electric motor, but with a small combustion engine that is used solely to charge the battery and extend its range. This second type is typically referred to as an Extended Range Electric Vehicle (EREV). For the purposes of this study, EREVs have been grouped under the broader PHEV heading.

3.2 Electric vehicles – cost effectiveness for consumers

The cost-benefit equation for a consumer considering purchasing an EV versus its internal combustion engine (ICE) equivalents is:

- EVs currently have higher up-front capital costs; but
- EVs benefit from lower running costs.
- BEVs suffer from inferior range relative to ICEs and PHEVs (see Appendix A for more detail).

The higher up-front capital cost is due to the relatively high cost of batteries and, for PHEVs, the extra cost of having a combustionengine (and often a second drive train) as well as an electric motor.

The lower running costs are due to:

- EVs' inherent energy efficiency: An electric motor is approximately four times more efficient at converting stored energy into motive power, than a combustion engine.
- Lower servicing costs: The lifetime servicing costs of a BEV are estimated to be less than 20% of an ICE. Electric drive trains are simpler than combustion engine drive trains, and the wear-and-tear on an electric motor is much less than for a combustion engine. Potential savings on PHEVs are not as great due to the greater complexity of PHEVs and the fact that they also have a combustion engine. However, savings can still be significant, with estimates of savings being in the range 40% to 70% of an ICE, depending on the type of PHEV.

Further, as discussed later, EVs currently avoid paying the majority of charges levied via petrol excise to fund the road network.



Figure 13 shows the estimated lifetime cost to consumers for three different 'mid-range'⁴⁰ vehicles – a petrol internal combustion engine (ICEp), a PHEV, and a BEV – for two different average annual travel distances (expressed as thousands of vehicle kilometres travelled (kVKT)).⁴¹

Figure 13: Lifetime consumer transport costs for new mid-range vehicle based on current prices



The capital cost premium of a new mid-range PHEVs and BEVs is estimated at \$15k and \$12k, respectively, on top of the ICEpequivalent price of \$30k, based on recent vehicle price data (there is a range in prices pending make model and specification level). However, there is significant uncertainty about capital cost estimates for PHEVs and BEVs due to differing pricing approaches⁴² and market positioning for the models currently available in New Zealand.

Running costs are based on recent data for petrol prices, electricity tariffs etc. The lower running cost of EVs means their relative economics improve for longer travel distances.

Figure 13 indicates that based on current prices, new ICEs have whole-of-lifetime costs that are between those of PHEVs and BEVs, where vehicles travel 10,000 km/year. For vehicles travelling 20,000 km/year, PHEVs and BEVs have lower whole-of-lifetime costs than ICEs. That said, current BEVs are less suitable for applications with higher annual travel distances – particularly if this is comprised of a number of very long journeys, rather than relatively high journey distances undertaken every day – because of their more limited range. As set out more in Appendix A, continued battery technology improvements means that range issues will become progressively less for BEVs.

is approximately 16 kVKT for new vehicles entering the fleet, and 12 kVKT for used vehicles entering the fleet (i.e. imported second-hand, typically from Japan). ⁴² This can be seen in the different prices for the same vehicle across various countries (i.e. even when allowing for taxes and exchange rates etc).

⁴⁰ A 'mid-range' vehicle is assumed to have a similar specification to a Toyota Corolla. A discount rate of 6% is used to take account of the time value of money.
⁴¹ The values of 10 kVKT and 20 kVKT were chosen because analysis in Appendix A demonstrates that the average distance travelled by a new vehicle in New Zealand



In all cases, EVs have a higher upfront cost than ICEs based on current prices. However, looking forward, the upfront purchase costs of EVs are expected to fall for two reasons:

• Firstly, as Figure 14 shows, battery costs are expected to continue to decline.

Figure 14: Historical and projected fall in battery costs (US\$/kWh of storage)



Source: Bloomberg New Energy Finance

• Secondly, EVs are likely to benefit from manufacturing economies of scale (as ICEs currently enjoy). This includes the likely emergence of a greater number of EV-only vehicle models, as

opposed to the manufacture of EV-versions of conventional ICE vehicles.

EV prices have already started to show significant reductions, with the price of the Nissan Leaf falling from \$69k to \$39k in approximately 5 years.⁴³ These reductions, which are not specific to New Zealand, may be more reflective of manufacturers seeking market share than true underlying production cost reductions. As EV sales accelerate worldwide, these cost reductions are expected to continue, with a number of vehicle industry analysts expecting EVs to reach purchase price parity within 5 to 8 years – although others say it could be 15 years' away.

Once purchase price parity is reached, and coupled with expected improvements in the range of EVs, EV vehicle sales could grow rapidly. However, this uptake could be tempered by the glut of existing ICE vehicles with significant remaining life which would likely reduce in price.

3.3 Electric vehicles – cost effectiveness for New Zealand

The rate of EV uptake will be influenced by the price signals that consumers face for vehicle purchase costs, electricity, petrol etc., since these signals determine the private benefits and costs of EVs to consumers.

If the price signals do not reflect the true (or 'public') level of costs and benefits, this will encourage over- or under-investment in EVs. It will also mean that New Zealand ends up with a vehicle mix that is less than ideal, with higher overall costs.

⁴³ Source: https://ecotricity.co.nz/electricvehicles/



Under existing arrangements, there are four key areas where significant misalignments in price signals are occurring:

- Three areas where EVs are likely being penalised relative to ICEs:
 - The electricity cost from charging EVs overnight generally being too high;
 - The payments which future EVs could earn from injecting power back into the electricity grid at times of peak demand being too low;
 - The price that ICE owners pay for the pollution from their tailpipe emissions being too low, relative to BEVs or PHEVs (to a lesser extent).
- One area where EVs are currently receiving a concession relative to ICEs: avoiding paying the same roading charges used to fund the road infrastructure.

This section addresses each of these issues in turn.

3.3.1 Electricity charging costs for EVs being too high

The principal 'fuel' for an EV is the electricity used to charge the battery. For most EV owners, the main place they will charge their battery is at home, where they will be charged the standard \$/kWh variable rate.

At present, there is wide variation in the price around the country which vehicle owners will be charged for charging their battery, with the GST-inclusive price ranging from 13 cents/kWh to 30.5 cents/kWh.

While some variation in price is expected due to different network circumstances, most of the variation appears to be due to other factors. These include:

- The meter set-up for the property specifically:
 - Whether there is a two-meter ("controlled" + "uncontrolled") or single meter ("inclusive") approach for charging for hot water.
 - Whether there is a separate night-only meter (or for households with advanced meters, whether the network company offers a night-only tariff).
- There is also variation in the extent to which retailers recover their retail cost-to-serve costs (metering, billing, marketing, etc.) via the variable or fixed component of charges.
- Lastly, there is variation according to whether a household qualifies for a low-user tariff, or not.

The scale of observed variation is summarised in Figure 15.



0.35 \$5/tCO2 assumed effective price of CO2 0.30 0.25 4 %γ 0.15 0.20 GST Retail Network **CO2** Wholesale 0.10 0.05 0.00 High Low Avg

Figure 15: Variation in charging prices for EVs

The impact of this variation is significant for the economics of an EV, as illustrated in Figure 16 below. Thus a BEV-owner driving 20,000 km a year may pay \$1,100 in electricity charging costs, or they may only pay \$470, depending on where they live and which supplier they choose.





A truly cost-reflective \$/kWh variable tariff would reflect the costs that are incurred from meeting increased kWh demand. This would better signal the resource costs of increased consumption in terms of increased wholesale, CO₂, network, or retail costs.

Other costs which don't vary with the quantity of kWh consumed should ideally be recovered based on their relevant cost-drivers. And costs which are entirely fixed should be recovered by via charges that have the lowest effect on consumer decisions.

With respect to the retail component of costs, these do not vary much with the kWh consumed⁴⁴ - it costs much the same to meter

⁴⁴ The only retail cost-to-serve item which is likely to vary with kWh consumed is bad debt write-offs. However, this is not a major component of retail operating costs.



and bill a customer who consumes 2,000 kWh as it does for one who consumes 20,000 kWh. Rather, some proportion of retail costs tend to vary with the number of customers, with others being completely fixed.

Accordingly, a fully cost-reflective \$/kWh variable charge would not have any retail cost-recovery component, with such costs instead being recovered via a fixed \$/customer charge.

As discussed in Chapter 2, network and generation costs vary across the day and year. Demand during a winter evening peak period is likely to result in significantly greater network and generation costs than off-peak demand in the early hours of the morning.

This is important because the analysis set out in Appendix A suggests that:

- the majority of EVs could be charged during the lowest demand periods over-night; but
- without any price-signal to encourage this, the greatest amount of EV charging would likely occur in the early evening – which in the winter, are the periods of greatest overall system demand.

Figure 17 below builds on Figure 15 previously, but also includes an estimate of the cost-reflective tariff that would apply for two different EV charging regimes:

- 'Smart', whereby a vehicle is charged overnight
- 'Simple', whereby a vehicle starts charging once it returns home each evening.



Figure 17: Comparison between current electricity prices for charging EVs and cost-reflective tariffs

As can be seen, a truly cost-reflective night-only smart tariff would be even lower in cost than the current lowest cost available to EV owners. This is because it would not have any network cost component within it, as such overnight demand would not result in any increase in network costs, nor would it have any retail cost recovery.

Conversely, a cost-reflective tariff for a vehicle which is predominantly charged in the early evening, would have a very large network cost component – much larger than current tariffs.



Experience both overseas and in New Zealand suggests that where consumers face a price signal for EV charging, they generally respond to it and concentrate their charging into lower-price periods.⁴⁵

Figure 18 builds on Figure 16 previously, and includes the annual electricity cost of charging a BEV if it were to face a cost-reflective tariff and be charged predominantly overnight (i.e. 'smart' charging).

Figure 18: Variation between current and cost-reflective cost of charging a BEV



The fuel cost for a BEV travelling 20,000 km/year that was charged via a cost-reflective smart tariff could be as low as \$300/year.

This is \$165/year lower than vehicles charged via the current lowest tariff, and \$560/year lower than vehicles charged via the average tariff shown in Figure 17.

This \$300/year bill compares with an ICE's annual fuel bill of approximately \$1,700/year based on the current world oil price of approximately US\$40/bbl. If oil prices were to rise to US \$80/bbl, this would rise to \$2,400/year.⁴⁶

The reason why a doubling of world oil prices doesn't result in a doubling of the non-roading-cost element of petrol prices, is because the pump price also incorporates a significant amount for the so-called 'importer margin'. This is for the recovery of costs relating to the building and operation of the petrol station network, plus the petrol company's profit margin.

Analysis published by the AA shown in Figure 18 illustrates how the world oil price component of petrol (referred to as 'Refined fuel' in the figure, is a relatively small component of petrol prices. The roading costs are the main component of the 'Fuel excise & ETS' component.

 46 In both cases, petrol excise taxes have been excluded from the ICE 'fuel' bill, as this excise is intended to fund roading infrastructure – a cost that is common to both EVs and ICE vehicles.

⁴⁵ Technology is increasingly facilitating such smart charging, including through vehicle owners being able to simply program a vehicle to not start charging until after a certain time (e.g. 11pm, or some other time when night rates start).



Figure 19 - Petrol cost breakdown⁴⁷



Source: http://www.aa.co.nz/cars/maintenance/fuel-prices-and-types/how-petrol-prices-are-calculated/

3.3.2 Potential payments for injecting back into the grid being too low

As well as drawing power from the grid to charge a battery, a number of more recent EV models have the ability *inject* power back into the grid.

⁴⁷ It is understood that the crude oil price used for this analysis was approximately US\$45/bbl.

The principal driver behind enabling such 'vehicle-to-grid' operation overseas is the ability for vehicles to inject power into electricity grids at times of peak grid demand – and therefore reduce the need for network and/or generation infrastructure to meet peak demand.⁴⁸ Similar benefits could arise in New Zealand, with EV injection reducing the extent of future investment required in generation and network assets to meet peak demand.

However, as discussed in Chapter 2, electricity tariffs are generally not structured to provide cost-reflective price signals at present.

Value of avoided generation costs

The potential generation benefit is avoided investment in infrequently-used generation assets – principally open-cycle gas turbines (OCGTs) – required to meet the few periods of highest demand. The upper value of such avoided investment is the cost for new plant. This is currently around \$145/kW/year – being the 'carrying cost' of building and maintaining an OCGT.

At times of peak demand, wholesale prices are likely to rise to levels to recover the cost of building such a peaking generator. Therefore, in theory, a battery injecting at times of peak could capture such prices and in so doing avoid the need for building such peaking generators.

However, to the extent that the system is in a situation of relative over-capacity (as has been the case in New Zealand for some time,

⁴⁸ Interest in vehicle-to-grid also grew after the Fukushima disaster in Japan, and the increased resilience that EVs provided in terms of providing a mobile source of electricity generation for consumers facing power outages.



and is expected to be so for a further 4 to 5 years) wholesale prices will not rise to such levels very often.

Value of avoided network costs

The potential network benefit is avoided future investment in assets to meet peak demand. This accounts for a large proportion of total network costs.

Over time, the value of reducing peak demand growth is the longrun marginal cost of network expansion. Appendix C sets out analysis which shows there is a very significant range of potential network LRMC values reflecting:

- Inherent variation in network circumstances in particular variation
 - In the cost of network expansion driven by rural/urban circumstances and other factors
 - In the extent to which the network is close to requiring additional investment in capacity
- Differences in methodologies used to estimate network LRMCs.

These variations give rise to a range in network LRMCs of between \$30 to \$300/kW/year depending on specific situations and methodologies.

Battery cost associated with grid injection

Lithium-ion batteries currently have a finite number of cycles in their economic life. Injecting power back into the grid will 'use-up' another battery cycle, bringing forward the time when the battery will need replacing or the car being sold. However, given that peak electricity demand periods, by definition, only occur for a relatively short amount of time each year, it is not considered that such costs would be significant.

Summary value of EV grid injection

Cost-reflective electricity tariffs to consumers should reflect the long-run cost of peak generation and network assets that will be required to meet growth in peak demand. These are expected to be the drivers of costs for the foreseeable future. However, it is not clear that an EV injecting into the grid will be able to capture all such value, as it is unlikely to be available for all the periods where such injection is required.

This could particularly be the case for avoided network investment in situations where there is already significant network load control such that the period requiring load control in high demand days extends to many hours during the day (i.e. a broad-flat 'peak'). One example of this is the Orion network where significant existing load control means that on cold winter days, load control is required for many hours during the day as well as the evening. It is unlikely that EV injection could materially contribute to meeting such a load control requirement.

This points to another issue – being the interaction with other load control, and the potential for *over-supply* of load control assets if large amounts were to come forward. i.e. beyond a certain point there is likely to be diminishing returns from additional peak demand management.

All in all, there is significant uncertainty over the extent of value that could be captured from peak injection. A mid-point value of



\$110/kW/year has been used, but with high/low ranges of \$320/kW/year to \$15/kW/year.

For PHEVs and BEVs with different sized batteries, this translates into the following estimates of the overall annual net benefit of grid injection.

Figure 20: Estimated range of value from EV grid injection



3.3.3 Pollution costs levied on ICE owners being too low

Greenhouse-related pollution

The principal area where fossil-fuelled vehicles are not facing the costs they impose on society relates to CO_2 emissions which are generally acknowledged to be a key cause of global warming. The effective CO_2 price incorporated into petrol and diesel costs for the first quarter of 2016 was NZ\$5/tCO₂ – which translates to 1 cent/litre.⁴⁹

However, there is a growing consensus that the societal cost from global warming is likely to be much greater than reflected in this current price.

The first report in this study used the emissions prices produced by the Business Energy Council (BEC) in 2015. For this study we have used the same prices for our low and medium estimates, respectively.⁵⁰

However, a growing number of international studies are estimating the 'true' cost of CO_2 emissions to be significantly greater than these levels. For example, one of the most comprehensive recent studies⁵¹ on the impact of global warming suggested the price required to prevent significant harm from global warming will likely need to be in the range US\$50/tCO₂ to US\$165/tCO₂ (NZ\$75/tCO₂ to NZ\$235/tCO₂).

⁴⁹ During Q1 2016, the price of a New Zealand Emissions Unit was approximately NZ\$10/tCO₂. However, with the current one-for-two surrender requirement that is part of the NZ Emissions Trading Scheme, this halves the effective price faced by emitters of CO₂.

⁵⁰ The average CO₂ price for the BEC's 'Kayak' scenario over the 20-year period of this evaluation is approximately $25/tCO_2$, whereas the 'Waka' scenario had average prices of approximately $50/tCO_2$ over this period.

⁵¹ "Better Growth, Better Climate. The New Climate Economy Report", The Global Commission on the Economy and Climate, Nicholas Stern et al, September 2014



We have adopted the mid-point of these two values (being approximately NZ $$150/tCO_2$) as our high estimate of the true societal cost of carbon. This translates to an addition on the petrol price of 42 cents/litre (incl. GST).

If this high CO₂ price were reflective of the true cost of CO₂, this means that a PHEV or BEV driving 15,000 km/year is disadvantaged compared to petrol vehicles by approximately \$370 or \$430/year, respectively.

Other vehicle-related pollution

There are also human health consequences from degraded local air quality from tailpipe emissions from combustion engines (particulates, SOx and NOx). In addition, the regenerative braking of EVs means there is less wear on brake pads and much less associated particulates released compared to ICE vehicles.

Lastly, electric motors are a lot quieter, which can therefore reduce the noise 'pollution' which can impact on people living near roads. Offsetting this noise benefit is a potential noise cost associated with accidents where pedestrians have not heard an EV approaching and stepping out into the road without looking.

However, we have not identified reliable estimates of the scale of emission-related human health costs. Further, these are likely to be very location specific. Thus, the human health costs of vehicle emissions in some of the Chinese cities are understood to be very high, whereas those in many New Zealand towns and cities are likely to be less.

Lastly, the most significant human-health related costs are understood to relate to diesel emissions, particularly from the light commercial and heavy transport fleet. Currently, the main competition for new EV purchases relates to petrol-driven light passenger vehicles. Once light commercial⁵² EV's become more widely available and adopted, there could be significant health benefits for people who are exposed to unfiltered air in the urban centres.

However, given all of the above, no estimate has been included in this study as to the potential additional non-CO₂ pollution costs relating to combustion engine vehicles.

3.3.4 EVs avoiding paying for the road transport network

New Zealand's roading network is not funded from general taxation, but by levies collected from vehicles. There are two main such levies:

- Petrol excise duty (PED) charged via a \$/litre charge on petrol sales;
- Road user charges (RUCs) charged on non-petrol driven vehicles (i.e. generally diesel-powered, for combustion engine vehicles), with vehicles having to purchase RUCs in advance.

Although PED is a \$/litre fuel-based charge, and RUCs are charged on a \$/km basis, the level of the PED is set so that a petrol-driven vehicle with an average fuel efficiency will pay a similar amount of roading

⁵² Electric and hybrid busses are also becoming more widely available, and starting to be adopted (e.g. the Wrightspeed bus drivetrain for Wellington City).


charge to a light diesel-driven vehicle travelling an equivalent distance.

However, Figure 21 below shows that extremely fuel-efficient petrol vehicles such as PHEVs will pay a much lower contribution to the road infrastructure.

BEVs, although they are classed as non-petrol driven vehicles, are currently exempt from paying RUCs as an explicit concession to encourage their uptake. This exemption is due to expire once electric vehicles make up 2% of the vehicle fleet.

Figure 21: Variation in roading charges between vehicle types⁵³



⁵³ ICEp and ICEd represent petrol and diesel vehicles, respectively. A more fuel efficient petrol vehicle will have a lower gradient – as illustrated by the very low gradient for a PHEV which consumes very little petrol per km driven, whereas the distance-based nature of Road User Charges (RUCs) used to recover roading costs from diesel vehicles, means their fuel efficiency has no bearing on how much they pay.

Assuming that RUC-based charges are a reasonable⁵⁴ reflection of roading costs, Figure 21 indicates that a PHEV or BEV driver who

The non-zero intercept of the graph is because in addition to PED and RUC, the road charges also shows the annual fixed costs associated with collection of fees for licencing, ACC, and WOF certification.

⁵⁴ It is likely that congestion-charges and the like are more cost-reflective approaches to recovering some roading costs. However, consideration of such issues is beyond the scope of this analysis. Further, *on average*, the RUC-based approach will deliver roughly the right apportionment between vehicles that travel different distances.



travels 15,000 km/year is currently receiving an annual concession of \$875 or \$930, respectively.

3.3.5 Summary of misalignments to EV economics

Figure 22 summarises the net effect of the differing price misalignments facing potential purchasers of EVs.

On balance, it appears that for the central estimate of the costs and benefits, the current avoided roading charge benefit largely balances out the cost relating to the other factors for BEV owners, and gives PHEV owners a net advantage by approximately \$250/year.

However, once the roading charge concession is removed when electric vehicles make up 2% of the vehicle fleet as currently planned, it will result in EV owners suffering a cost penalty relative to ICE vehicles of approximately \$900/year for PHEVs and \$1,250/year for BEVs.

2.500 Other ICE pollution Assumed VKT = 15,000km/yr 2.000 impacts not priced 1,500 ■ CO2 price too low \$/yy (incl. GST) 1,000 Elec injection potential not 500 realised Elec charging cost too high -500 Roading charge avoided -1,000 ⊖ Current net -1,500 Med High Med High Low Low PHEV BEV ConsumerTech v17.xlsm

Figure 22: Summary of current price misalignments for a 15,000 km/year vehicle

3.4 Overall economic impact of current pricing misalignments

Assuming the roading charge exemption is removed as planned, the other pricing misalignments are expected to slow the uptake of EVs relative to optimal levels, with two main negative outcomes for New Zealand:

- New Zealand spending more on transport than it should (largely in the form of imported fuel, rather than New Zealand-generated electricity)
- materially greater CO₂ emissions.



An estimate was undertaken of the scale of economic cost that would be incurred if these misalignments were to result in 2% of vehicle sales each year being ICE vehicles rather than EVs. This resulted in an NPV figure of \$560m over 20 years.

To the extent that the actual extent of frustrated EV uptake being higher or lower than this 2% figure, the scale of economic cost will scale accordingly.



4 Solar photovoltaics (PV)

4.1 Introduction

As Figure 23 and Figure 24 illustrate, rapid improvements in the performance and cost of solar photovoltaic technology has resulted in strong growth in the amount of PV capacity being installed around the world.

Figure 23: PV cost reductions



U.S. Installed Cost of Solar Power (\$/kilowatt)

Figure 24: Growth in PV installation



Source: IEA

In New Zealand, less than 1% of households currently have solar PV, but there has been growing uptake, as shown in Figure 25.





Figure 25: Residential solar PV uptake in New Zealand

Source: Concept analysis using Electricity Authority data

4.2 Solar PV – cost effectiveness for consumers

There are four main components to the up-front costs of a rooftop PV system for consumers:

- The costs of the *panels*
- The costs of the *inverter* used to convert the direct current (DC) power generated by the panel into the alternating current (AC) power that is supplied into consumers' homes.

- The costs of *installing* the system. This includes the cost of labour and other materials (cabling and metering), and the costs of getting council and electricity network company approvals.
- Goods and services tax (GST).

Most of these costs broadly scale with the size of system, while some (e.g. council approvals, and some aspects of the labour costs) don't vary much with the size of the system.

Figure 26: Estimated 2016 up-front costs of rooftop solar PV systems



Figure 26 shows the estimated overall cost to consumers of installing different-sized rooftop PV systems, based on current prices. The fact that some costs are fixed means that there are economies of scale



with rooftop solar PV – as indicated by the downward sloping nature of the curve which expresses the costs on a \$ per Watt basis.

The 'replacement inverter' cost item is to take account of the fact that most systems will need their inverter replacing approximately half-way through their life. The replacement inverter cost is the estimated 'present value' of this cost which is likely to occur in ten years' time.⁵⁵

The cost estimates shown in Figure 26 are based on advertised retail costs for so-called 'grid-tie' PV systems.⁵⁶ These advertised costs are shown in Figure 27 below.⁵⁷



Figure 27: 2016 Grid-tie PV advertised retail costs in New Zealand

The above estimates are based on installing a solar panel on an existing property, and based on current industry scale. If a solar panel is installed at the time the property is built and the PV industry has the benefits of scale, the installation costs will be significantly lower. If 50% of installation costs were avoided, this would result in the installed cost being approximately 15% less for a 2kW system and 10% less for a 4kW system.

⁵⁵ This calculation takes into account the likely continued reduction in inverter costs (assumed to be [3.5%] per year), and uses a [6%] discount rate for the present value calculation.

⁵⁶ A 'grid-tied' PV system is one that is connected to the electricity grid (albeit via being wired-in to a household's wiring). This compares with systems for consumers who are completely off-grid. Having a grid-tie system requires

inverters to convert the DC power into the AC power that is transported across the grid into people's homes.

⁵⁷ As can be seen, there is a significant variation in pricing due to factors such as: System quality; what is assumed to be included excluded; the ratio of inverter size to panel capacity; and additional install costs (for long travel distance, atypical roof, etc). Concept has chosen a baseline estimate of solar PV costs which are at the lower end of this observable range.



There are no variable operating costs to speak of (sunshine is free!), but there is a need to clean the panels a couple of times' a year to remove any dust, bird droppings and the like. Not cleaning the panels will reduce their effectiveness, and in some cases may actually damage them.⁵⁸ Some people may be able to clean their panels on their own without too much effort, whereas others may need a window cleaner do the job. Our base case estimate of the annual maintenance costs of a rooftop panel is \$25/year.

In order to more readily compare the up-front purchase costs and annual maintenance costs with the benefits from solar PV (i.e. the avoided cost of purchasing power plus any export sales they may make – both of which are expressed in terms of \$/kWh), these fixed costs have been 'levelised' to give a levelised cost of ownership (LCOE) expressed in \$/kWh.

This involves:

- i) 'Spreading' the up-front purchase costs over the life of the panel using a cost of borrowing to come up with a resultant annualised capital recovery amount
- ii) Adding the annual maintenance costs
- iii) Dividing these annual costs by the annual kWh production of the solar panel.

In calculating the annual kWh production of the panels, two factors need to be taken into account:

1) How sunny it is, and thus how much will be produced. A simple means of expressing this is the 'capacity factor' of the panel. If

the panel were generating at full output 24 hours a day, 365 days a year it would have a capacity factor of 100%. However, as Figure 28 illustrates, the sun doesn't shine overnight, and there is significant within-day and within-year variation in the amount of sunshine (including due to cloudy periods).

Figure 28: Average solar PV output profile



This means that the capacity factor of a typical, well-oriented panel in New Zealand is likely to be approximately 14.5%. This compares with sunnier climates such as Queensland in Australia where capacity factors are approximately 17.5%.⁵⁹ It should be noted that the variation in average sunshine levels throughout New Zealand will result in a variation in the

www.concept.co.nz

59

⁵⁸ For some technologies, having a cell within a panel permanently shaded (e.g. by a bird dropping) can damage the whole panel over the long term.

Based on average daily output of 8.4 kWh for a 2kW panel in Brisbane.



likely capacity factors, likely ranging from approximately 13% to 15%.

Further, this assumes that the roof is well-oriented (i.e. north-facing) and not shaded by trees, hills or other buildings. The majority of residential properties are not expected to be unduly affected by poor orientation (noting that some – i.e. apartments – are inherently unsuitable).

2) The output of solar panels will degrade over time irrespective of how well they are cleaned. Different panels degrade at different rates. Our base case assumption is that there will be no degradation for the first five years' of a panel's life, but that there will be a steady rate of degradation from that point, until by year 20 their output is 87.5% of the original installed output.

Taking all these factors into account results in the up-front costs shown in Figure 26 being translated into the $\frac{1}{kWh}$ levelised costs show in Figure 29. The downward sloping nature of the curve reflects the economies of scale associated with household PV – i.e. if the fixed costs of installing a panel can be spread over a greater number of kW, the effective $\frac{1}{kWh}$ cost will fall.

It should be noted that the levelised costs indicated in Figure 29 below does not represent the 'break-even electricity tariff' at which PV becomes cheaper than grid electricity (the 'break-even' tariff is higher). This is because consumers will almost always be exporting some electricity to the grid (see section 4.3 below).

The three different lines in the graph show the effect of three different periods for recovery of the capital cost of the panel. Although PV panels will almost certainly last 20 years, it is possible that consumers may seek to recover the costs of the panels over a

shorter period. This would increase the required \$/kWh benefits of solar PV to break-even.

For the cost-benefit analysis discussed later, we have assumed consumers evaluate costs and benefits over the next [20] years.

Figure 29: Estimated levelised costs of rooftop PV installed in 2016



4.2.1 Possible future reductions in the cost of solar PV

As well as evaluating solar PV based on current costs, we have considered the benefits of installing solar PV in future years given that solar PV costs are expected to continue to decline.



Our central estimates for further cost reductions are:

- Panels = 7% p.a.⁶⁰
- Inverters = 3% p.a.
- Installation = 3.5% p.a.⁶¹

As shown in Figure 30, these assumptions mean that the cost of a rooftop solar panel installed in ten years' time (i.e. in 2026) could be 40% less⁶² than the cost of a panel installed this year, and will roughly halve by 2030.



Figure 30: Projected (real) rate of decline of costs of installed rooftop solar PV systems

inverters), it is considered that there are in fact significant potential opportunities for reducing such costs. In this, the experience of Australia points to large scale uptake of PV resulting in considerable innovation in installation.

⁶² This is consistent with independent PV cost reduction estimates in Transpower's 'Transmission Tomorrow' document.

ConsumerTech_v15.xlsm

⁶⁰ The rate of cost reduction in panels is based on an observed learning curve factor of 20% (i.e. the cost reduction achieved from a doubling of global installed capacity), and a continuation of the 25% p.a. rate of increase in installed global solar PV capacity. If the rate of world solar uptake doesn't continue at this level, this is likely an over-estimate of the future rate of cost-reduction in solar PV. ⁶¹ Although installation costs are largely labour (and thus ostensibly don't have the same potential for technology and manufacturing improvements as panels and



4.2.2 The cost of commercial and utility-scale PV

While a lot of the focus has been on residential rooftop solar PV, there is also growing interest in developing much larger-scale solar PV facilities:

- On warehouse / factory roofs, resulting in implementations of hundreds of kWs to several MW
- As 'utility-scale', land-mounted implementations of tens of MWs.

Implementations of these sizes can capture significant economies of scale, through sourcing panels and inverters at lower cost, and having much lower installation costs on a \$/kW basis.

Further, utility-scale land-mounted implementations have the potential to have more sophisticated mountings including tracking technology which moves the panels so that they 'track' the position of the sun in the sky. While these are more expensive, they result in a greater solar yield.

Taken together, overseas experience indicates that these types of large-scale solar installation are estimated to result in a \$/kWh cost of solar PV which is approximately one-half to two-thirds the cost of residential rooftop solar systems.

4.3 Value of PV generation to consumers

For a PV-owning consumer there are two principal monetary benefit streams⁶³:

- 1. Avoiding the cost of purchasing electricity from the grid to meet their household electricity needs.
- 2. Earning money from 'exporting' surplus PV power onto the grid from times when the amount of power generated exceeds the household's consumption of electricity.

If the weighted average of these two benefit streams is less than the levelised costs shown in Figure 29, investing in solar PV would be cost-effective for a consumer.

While calculating the levelised costs of a solar system is 'relatively' straightforward, estimating the value of PV generation to consumers is more complex and subject to variation. In this respect, the key complicating factors are:

- Electricity purchase tariffs vary significantly around the country, and by a consumer's situation;
- The mix of PV export and self-consumption varies across consumers noting that the export tariff is typically much less than the avoided electricity purchase tariff.

⁶³ Some consumers may also perceive benefit in terms of 'doing their bit' for the environment, or improved reliability in terms of being more resilient to power cuts (although this latter factor requires them to also have a battery). These more intangible factors are not considered in this economic evaluation.

Further, as the first report in this study highlighted (available at <u>www.concept.co.nz/publications.html</u>), solar PV in New Zealand is unlikely to materially reduce CO₂ emissions, and may actually *increase* them in the long run. Section 5.1, considers the specific issues relating to households combining solar PV with batteries.



• The extent to which the purchase and export tariffs are likely to change over the lifetime of the PV panel.

Each of these factors is discussed below.

4.3.1 Variation in the tariff that can be earned by solar PV

The greatest value a consumer can currently achieve from installing solar PV is through avoiding the costs of electricity purchased to meet their own demand.

However, as Figure 31 shows, there is considerable variation across New Zealand regarding the costs that electricity consumers face for their electricity purchases – and thus the value which can be 'earned' by self-consumption of solar PV output.





Figure 31: Variation in typical residential electricity purchase tariffs that could be avoided from installing solar PV⁶⁴

Some consumers may only be able to 'earn' 16 c/kWh for their solar electricity, whereas others can achieve over double that by avoiding a 36 c/kWh tariff – which, with reference to Figure 29 previously, is greater than the 20-year levelised cost of a medium-sized solar PV system.

This variation in retail tariffs has a major impact on the costeffectiveness to consumers of installing solar PV.

There are a number of key factors behinds such variation:

Late paying consumers will be penalised by the loss of the PPD, which can increase their bills by between 5% to 22%.



- Variation in how the network company meters electricity. The principal variation (which is illustrated in Figure 31) is whether the network company meters on a two-meter⁶⁵-basis ('Controlled' + 'Uncontrolled') or a single-meter basis ('Inclusive'). In a twometer set-up the discount for controlled hot water is separately identified as a 'controlled' meter, whereas for a single-meter setup it is 'bundled' within an 'inclusive' tariff. This means consumers who are charged via an inclusive tariff effectively earn less for their solar PV output than those whose main electricity demand is charged via an uncontrolled tariff. Offsetting this tariff dis-benefit for single-meter set-ups is the fact that the entire household electricity demand can be offset against solar PV generation for single meter set-ups, whereas only the 'uncontrolled' meter's demand can be offset against solar generation for two-meter set-ups. As is illustrated later, this means that two-meter set-ups typically result in greater amounts of solar PV export.
- The requirement for networks and retailers to offer a 'low-user' charging option. Such an option has a low fixed charge, but a higher variable charge. As shown in Figure 31, one effect of this is for consumers on a low-user tariff to earn significantly more than they could if they were on a standard tariff. As discussed in section 4.4, having solar PV means that it is much more likely that consumers net consumption will fall below the 8,000 kWh/year threshold to qualify as a low-user.

- Variation in approach by networks and retailers as to the proportion of their costs recovered via fixed charges (which can't be avoided by installing solar PV) versus variable charges (which can be avoided by solar PV).
- Some variation in the actual costs of building and operating networks in different areas.

The most significant drivers behind this variation in the prices to consumers is not driven by fundamental differences in the actual costs of supplying consumers with electricity, yet this variation is having a major impact on consumers' decisions – including whether to install solar PV. This dislocation between cost and price is examined in section 4.4.

There is also variation in the buy-back rates that retailers offer consumers for purchasing any PV power that is exported onto the network. However, as Table 1 illustrates, the scale of such variation is not as significant as the scale of variation in electricity purchase tariffs.

⁶⁵ Some customers will have one 'smart' meter, but two registers, but regardless of metering technology, the outcome is the same.



Table 1: Solar PV buy-back rates⁶⁶

Energy Retailer	Solar Power Buy Back Rate	Max. System Size
Contact	8¢ / kWh, excl. GST	Up to 5kW
Mercury Energy	8¢ / kWh (with the exception of a couple of networks)	-
Trust Power	7¢ / kWh, + GST	Up to 10kW
Meridian	7¢ / kWh in summer and 10¢ / kWh in the winter, +GST	Up to 10kW
Genesis	4 - 7¢ / kWh (location dependant)	-
Ecotricity	7 - 8¢ / kWh + GST	Any size

4.3.2 Variation in the balance between a consumer's demand and solar PV generation

Figure 31 and Table 1 highlight that the value a consumer can achieve from avoiding electricity purchases (typically of the order of 26 c/kWh, incl. GST) is over three times the value that could be earned from selling surplus PV power (typically 8 c/kWh excl. GST).

Accordingly, the size of panel and the level and within-day consumption patterns of the consumer can have a major effect on the economics of solar PV. If a consumer installs a large panel and/or they don't consume much electricity – particularly during the middle of the day in summer when most solar PV is generated – then the majority of their power will earn a lower value. Conversely, a smaller panel which results in less export will improve the average amount

⁶⁶ Source: <u>https://www.mysolarquotes.co.nz/about-solar-power/residential/solar-power-buy-back-rates-nz/</u>, as at 21-Mar-2016. GST is only paid to consumers who are registered for GST purposes.

'earned' by the panel – but, as shown in Figure 29 previously, with a penalty in terms of the levelised cost of such panels.

To examine this panel size trade-off, we simulated the operation of different-sized PV panels for varying household consumption situations. These consumer situations sought to reflect the range of levels and patterns of household consumption based on:

- Whether the household has electric space heating, or not;
- Whether the household has electric water heating, or not;
- Whether the household is occupied during the day, or only in the morning and evening;
- Whether the consumer had a 'Small', 'Medium' or 'Large' amount of consumption.⁶⁷

Taken together, this results in a range of different consumer demand situations for the various combinations of the above factors, with a significant range of resultant total demand – as illustrated by Figure 32.

For reference, MBIE data indicates that average household electricity demand in New Zealand is approximately 7,300 kWh/yr.

⁶⁷ The levels of consumption for space heating in particular were varied according to the consumer's location. Thus the space heating demand for an Auckland consumer was modelled to be a lot less than for a Christchurch consumer.



Figure 32: Range of modelled consumer electricity demand situations



These different consumer situations were assessed against different solar PV panel sizes, and for different locations (to take account of differences in the amount of sunshine around New Zealand).

Lastly, the model distinguished between households with 2-meter versus 1-meter configurations (i.e. separate registers versus single register for so-called smart meters) – noting that a 2-meter configuration will only result in the solar PV offsetting demand from the uncontrolled meter, whereas solar PV will offset the entire household consumption for a 1-meter configuration.

In total, this resulted in approximately 1,000 different combinations of consumer situations being modelled.

The assessment simulated the hourly consumption and solar PV production over a two-year period. This used actual hourly sunshine data from NIWA to model the output from a solar panel, and actual hourly temperature data from NIWA to model the demand from electric space heating. The hourly data for each was for exactly the same historical time period – being 2011 to 2012.

Modelling solar PV production and space heating demand on an hourly basis, rather than using 'typical' profiles for both is important because of the major weather-driven variation for both, resulting in significant differences in modelled outputs (particularly the amount of export) compared to if 'typical' profiles were used.

This is illustrated in Figure 33, which shows an extract of a summer and winter week for one of the consumer situations modelled. It shows how the level of export varies significantly from day-to-day depending on how cloudy it is. If a simple average curve of PV generation were used for a summer or winter day, it would significantly under-estimate the extent of export.



40 3.5 3.0 Export 2.5 Offset demand **4** ≷ 2.0 Demand 1.5 _____P\/ 1.0 0.5 0.0 1 1019 6-Dec- 7-Dec- 8-Dec- 9-Dec- 10- 11- 12- 30- 1-Jul- 2-Jul-3-Jul-4-Iul 5-Jul-12 12 12 12 Dec-12Dec-12Dec-12Jun-12 12 12 12 12 12 12 Summer Winter ConsumerTech_v15.xlsm

Figure 33: Simulated balance between solar PV export and offset demand for a typical consumer situation

Conversely, the within-day and within-year consumption patterns for water heating and other electricity demand were based on standard within-day and within-year consumption patterns for these load types. This approach appears reasonable because consumption patterns (other than space heating) are less affected by weatherdriven variation. If anything, this approach is likely to slightly underestimate the amount of solar PV that will be exported.

Figure 34 shows the estimated proportion of solar PV power that would be exported for the range of different consumer situations that were modelled.



Figure 34: Modelled proportion of solar PV power exported for different consumer situations

This illustrates that even with a 'medium-sized' 4 kW array and a consumer with a relatively large level of demand, a significant amount of the power could be exported.

4.3.3 Uncertainty over future changes to electricity demand and PV export tariffs

When evaluating the benefit of a solar panel, it is important to take account of any future increases in electricity prices – noting that such price rises will increase the lifetime benefits of solar PV.

As is shown in Figure 35, residential consumers have experienced significant price rises over recent years.





*Figure 35: Historical average residential electricity prices (real, 2015 \$, incl. GST, YE March)*⁶⁸

Source: Concept analysis using MBIE data

Over the period 2003 to 2015, the average real annual price increase was:

- 3.7% for the 'Energy' component
- 2.4% for the 'Lines' component
- 3.1% overall

Many consumers putting a panel on their roofs are seeking to protect themselves from possible future price increases. Indeed, some companies selling solar panels suggest that the recent real price increases will continue at similar, or greater, levels into the future. However, the available evidence suggests that this is unlikely:

- The forward wholesale price curve which reflects wholesale buyer and seller expectations of future prices is relatively flat. This appears to be realistic as:
 - The underlying fundamental costs of generation are not expected to change materially going forward – unlike the increases over the last decade which largely reflected the transition from cheap-gas to new low-emission options such as geothermal or wind generation.
 - The cost of building new geothermal or wind farms is not expected to rise materially in real terms – particularly as wind continues to enjoy significant technological improvements which continue to bring the cost of the technology down.
 Further, wind costs are largely independent of CO₂ prices, meaning that a rise in CO₂ prices would have a significantly diluted impact on New Zealand's wholesale electricity prices.
- Retail costs (the costs of metering, billing, marketing, etc.) have risen materially over the twelve-year period, to the point where they now account for approximately 33% of the energy component. However, over the most recent years, such costs appear to have levelled off, and may even be falling. This may

⁶⁸ The numbers presented include any fixed charges which have effectively been 'variablised'.



reflect a combination of increasing retail competition, and the fact that many retailers have largely finished implementing major back-office systems replacements.

• Lines (a.k.a. 'network') costs are expected to increase further. However, the scale of increase is not considered to be significant, particularly as the major transmission investments that drove much of the recent increases have now been completed.

Figure 36 below presents the projected cost increases that have been assumed for energy, network and retail components of consumer tariffs in real terms.



Figure 36: Projected real price increases of residential tariff cost components relative to 2016 levels

The effective impact on the total bill depends on the relative weighting of each sub-component, as shown in Figure 37.



*Figure 37: Breakdown of retail tariff cost components for an average variable residential tariff*⁶⁹



4.3.4 Overall evaluation of likely cost-benefit of solar PV to consumers

Figure 38 shows the average cost-benefit evaluation across all the consumer situations ('physical' situations and tariff levels faced) modelled for three different sizes of PV system.

Figure 38: Average lifetime consumer cost-benefit of solar PV based on current retail tariffs (incl. GST)



Figure 38 indicates that solar PV is not currently cost effective for most of the consumer situations modelled.

A key reason for this outcome is that on average across these different consumer situations, most PV output is exported, which attracts a lower monetary reward than self-consumption of PV

current one-for-two obligation under the New Zealand Emissions Trading Scheme, halves the effective price.

 $^{^{69}}$ The CO₂ price used for this reflection of current tariffs assumes an effective CO₂ price to fossil generators of \$5/tCO₂ – i.e. a price of \$10/tCO₂ which, after the



output – as shown in Figure 39 which shows this trade-off across all the consumer situations modelled for the 4 kW solar panel scenario.

Figure 39: Difference between kWh use of solar power and value of such use for a 4kW system based on current retail tariffs



However, as Figure 34 highlighted, not all households are the same, with significant variation in how much power they consume, and when they consume it. There is also significant variation in the retail price they face depending on where in the country they are and whether they qualify for low-user tariffs.

Figure 40 presents the distribution of modelled outcomes across the ~1,000 different consumer situations that were simulated (i.e. across the range of consumption levels and patterns, solar PV sizes, regional locations, and tariff levels).

Figure 40: Modelled variation in current consumer net present value (NPV) of solar PV investment



Based on present costs and electricity tariffs, solar PV is estimated to be cost effective for less than 1% of modelled situations. However, there are a number of caveats to this analysis. These include:

- The analysis is for installing solar PV on existing properties. If solar PV is installed at the time the property is built, the NPV evaluation could improve by approximately \$750 \$1,500.
- The analysis assumes that consumers evaluate solar PV over a 20year period. If a shorter investment horizon is applied (e.g. 10 or 15 years), the net present value equation will be substantially worse. (e.g. the average 10 year NPV for a 4 kW system is a loss

www.concept.co.nz



of \$7,700 compared with a loss of \$4,900 when evaluated over a 20 year period).

It is important to note that Figure 40 shows the estimated distribution of outcomes for the ~1,000 modelled household situations *if* they installed solar PV. It does not provide information about the distribution of outcomes for households that *have* actually installed solar PV.

The reason for this is that households for whom the financial attractiveness of solar PV is relatively higher (i.e. those in the righthand 'tail' of the distribution) would be more likely to be early adopters, all other things being equal. So for example, early adopters are more likely to reside in sunnier regions, have lower export proportions because they use power throughout the day, and have sought to optimise the panel size to their power usage etc.

Looking ahead, solar PV is expected to enjoy continuing significant cost reductions. Based on our central cost-reduction projections outlined on page 23, Figure 41 shows how the distribution of consumer net present values is expected to improve. This indicates that solar PV would become cost effective for around 40% of the modelled situations in 10 years, based on current electricity price structures. And in 20 years' time solar PV would be cost effective for most modelled situations – if retail tariff structures continue unchanged.⁷⁰

Figure 41: Change in consumer NPV of solar investment - based on

continuation of current tariff structures

4.4 Solar PV – cost effectiveness for New Zealand

As with EVs, the rate of solar PV uptake will be influenced by the price signals that consumers face, since these signals determine the net benefits of solar PV from the perspective of consumers.

If the price signals do not reflect the true (or 'public') level of costs and benefits, this will encourage over- or under-investment in solar PVs. It will also mean that New Zealand ends up with a mix of energy sources that is less than ideal, with higher overall costs.

need to be multiplied by approximately 2/3 to arrive at estimates of households for whom solar is likely to be economic.

^{10%} 9% 8 1% 5% 5% -2016 4% -2026 3% -2036 2% -3,500 -2,500 -1,500500 3,500 10,500 -9,500 500 -6,500 -5,500 -4,500 -500 500 2,500 4,500 500 500 500 8,500 500 500 500 ۰<u>،</u> ó ດັ Ő 00 5 N Net present value of solar PV investment made in year (\$) ConsumerTech_v15.xlsm

⁷⁰ It is likely that a significant proportion of houses will not have roofs which are suitable for solar PV (e.g. apartments), plus rental properties may also be less likely to have solar PV installed. These factors may mean that the above proportions



This section examines whether the signals being sent to consumers reflect the true benefits and costs of solar PVs, by considering the structure and composition of tariffs charged to residential electricity consumers.

For the year ending March 2015, the average residential electricity bill was \$1,940, split between the cost categories shown in Figure 42.

Figure 42: Estimated breakdown of underlying costs of the average residential bill for YE March 2015



⁷¹ Sometimes the electricity to supply a hot water cylinder is metered via a second meter with a lower variable charge to reflect the fact that the network company

- **Generation** costs cover the costs of building, operating and maintaining grid-connected power stations (e.g. wind, geothermal, hydro, gas-fired, etc.), plus fuel and CO₂ costs for fossil-fuelled stations.
- **Network** costs (a.k.a. 'Lines' costs) cover the cost of building and maintaining the transmission and distribution wires to transport electricity from generators to consumers.
- **Retail** costs include metering, billing, marketing, and customer service such as operating call centres.
- **GST** is the goods and services tax.

Although these different components give rise to distinct costs in supplying electricity, they are generally 'bundled' together in the final price charged to consumers. Typically, this is in the form of a single \$/day fixed charge and one or more \$/kWh variable charges⁷¹ – with the majority of costs being recovered via the variable charges.

Although consumers can't avoid paying the fixed charge – unless they go completely off-grid – a consumer who installs a solar panel on their roof can reduce the level of variable charges they pay by self-consuming solar PV power, and reducing their use of gridsupplied power. This can mean that solar PV is cost effective for a consumer.

However, it will only be a good investment for New Zealand if the reduced consumption genuinely avoids the costs which were recovered via the variable component of the charge.

can 'control' the hot water (i.e. cut of supply to the hot water cylinder) at times of peak system demand.





Figure 43: Estimated cost breakdown of typical variable tariffs⁷²

Figure 43 shows an estimated average cost breakdown of variable tariffs (this is the same as Figure 31 shown on page 26 previously).⁷³

The next sub-sections discuss the extent to which each of these cost categories will vary with the level of consumption of grid-supplied power.

4.4.1 Avoided retail costs due to solar PV

In the case of the retail component of costs, having solar PV will not avoid the need for meters, meter reading, billing, advertising, call centres, and any of the other costs incurred by retailers in providing electricity to consumers (unless the customer is completely off-grid).

Indeed, retailers generally incur increased costs through having to undertake extra billing and payments for the purchase of any surplus power that customers 'export' onto the grid at times when their consumption is less than their solar generation. As there are currently relatively small numbers of solar PV customers, the costs of developing the systems and processes to handle these customers are understood to be significant on a per customer basis – although still relatively small in terms of the overall costs of running a retail business.

For this analysis, we haven't attempted to estimate the size of any additional retail operating costs associated with providing service to households with solar PV.

⁷² The 'Generation' component of costs shown in Figure 42 has been split into an 'Energy' component and a 'CO₂' component to aid consideration of the extent to which CO₂ costs factor into household electricity costs, given the environmental focus of many of these new technologies. The breakdown of costs uses recent values for energy and CO₂, namely: an \$80/MWh baseload electricity price, and a $$5/tCO_2$ effective price of carbon – both of which are factored by the shape of residential demand and avoided network losses to arrive at a demand-weighted average price.

⁷³ The reason that there is no difference for the Energy & CO2 components of cost between the different situations is because, unlike Network and Retail costs, there are no fixed costs which need to be variablised to be compliant with the low-user fixed charge regulations. Further, only the Network component of costs shows variation between Uncontrolled and Inclusive tariffs, as these are the only costs whose tariffs for recovery vary according to one- or two-meter set-ups.



4.4.2 Avoided network costs due to solar PV

One of the most important long-term drivers of networks costs is having sufficient network capacity to meet the few periods of highest demand (e.g. a cold winter's evening).⁷⁴ Other network costs are largely independent of energy demand, and more driven by factors such as the number and density of connections in a network, or whether the network is built in the country, town or city.

Clearly solar PV can't alter the number or density of connections, but in principle it could have an impact on peak demand if solar panels are generating at such times – and thus reduce network costs. In New Zealand, peak demand typically occurs around 6-7pm on a very cold winter evening, when people come home from work and turn on the heating to high (as well as the cooker, lights, TV etc.). However, typically at 6-7pm in July there is little or no sunshine – particularly during the coldest days with the worst weather.

To illustrate this, Figure 44 shows the output of the model described on page 29 which looks at the variation in residential consumption across the day and year, including using real hourly temperature and sunshine data to model the amount of heating demand and solar PV output, respectively.



Figure 44: Variation in solar PV output with residential demand

At the times of highest demand (the right-hand side of the x-axis) solar PV generation is zero. Accordingly, solar PV will generally⁷⁵ not have any impact on peak network demand, and therefore not materially reduce network capacity costs. Nor it is expected to

evenings, nights or times when it is cloudy, so even in these summer-peaking networks, solar PV may not have a material impact on reliably reducing peak network demand.

⁷⁴ For example, the Christchurch distributor, Orion, has indicated that around 50% of its costs in the long-term are driven by peak demand. [p21 of Orion's 1 April 2015 *Methodology for deriving delivery prices*].

⁷⁵ There are some rural parts of the network where peak demand occurs in the summer due to irrigation. Further, such irrigation demand can occur in summer



reduce other costs, because they are driven by factors such as customer density, network age etc.

Further, recent research by the EPE Centre as part of the Green Grid project is highlighting that high levels of solar PV penetration can result in reverse power flows – i.e. power flowing back up the distribution network towards the transmission network, e.g. around lunchtime on a hot mid-week January – which will push the network beyond its voltage tolerances. Such outcomes have already occurred in parts of the world which have high uptake of solar PV.

In order to manage this, networks will have to invest in remedial technologies to accommodate reverse flows. The extent of solar PV penetration before a low voltage network is pushed beyond its tolerances will vary due to a range of factors, with some feeders being able to handle relatively high penetrations (e.g. 40-50%), whereas others only being able to handle 10% penetration.⁷⁶

Given the lack of hard data on the potential scale of increased network costs to manage higher solar penetrations, we haven't included an estimate of such costs in our analysis of the net public cost-benefit of solar PV.

4.4.3 Avoided energy costs of solar PV

With regards to the energy components of a retail tariff, the price that is charged consumers is based on the <u>demand-weighted</u> average cost of wholesale energy.

Figure 45 shows a typical within-day and within-year distribution of wholesale energy prices.

Figure 45: Typical shape of wholesale energy prices⁷⁷



This shows that energy costs are greatest at times of morning and evening peaks, lowest overnight, and greater in winter than in summer, and greater during business days ('b') than non-business days ('n').⁷⁸ This distribution of prices is predominantly driven by the pattern of national power demand (highest on winter business days etc, requiring more expensive supply sources at those times).

⁷⁶ Such factors include variation in customer density, mix of residential and commercial, the capacity of the network, whether it is over-ground or underground, etc.

⁷⁷ This shape has been based on analysis of historical spot prices, and scaled to achieve a time-weighted average which is exactly \$80/MWh.

⁷⁸ Month-to-month and year-to-year there can be significant variation to this shape due in particular to: variation in hydro inflows given that 60% of our



Retailers typically⁷⁹ charge customers a tariff that is constant across the day and year, and which therefore reflects a demand-weighted average of energy prices (noting that typically residential consumers use more power at times of higher electricity prices – as illustrated by comparing Figure 46 below with Figure 45).

Figure 46: Illustrative residential consumption profile



The price charged to consumers also needs to take account of distribution losses associated with transporting the electricity from the transmission grid to individual households – roughly about 5.5%.

Taking account of both the shape of prices and demand and network losses, this can result in a demand-weighted average wholesale component of price for residential consumers which is approximately 17% higher than the time-weighted average price received by grid-scale generators.

To value the extent to which solar generation avoids grid-scale generation costs, the same basic approach is required – except that it is necessary to use the profile of solar generation – as illustrated in Figure 47 – to calculate a *generation*-weighted average price.

⁷⁹ Some recent retailer new entrants such as Flick Electric have started offering customers time-of-use tariffs which pass on directly the half-hour wholesale spot price. However, these currently account for a small percentage of the overall residential electricity market.

generation is from hydro power, and variations in the extent to which the system is in a state of relative generation surplus or scarcity. However, on average prices tend to exhibit the shape shown in Figure 45.



Figure 47: Typical solar generation profile



Likewise, solar PV generation connected to a residential network needs to be rewarded for avoiding network losses associated with transporting grid-scale generation to individual households.

Using the solar PV generation and wholesale price shapes shown in Figure 47 and Figure 45, and taking avoided network losses into account, results in a generation-weighted average price which is 9.9% higher than the time-weighted average price received by grid generation.

Assuming an \$80/MWh time-weighted average wholesale price for such grid generation, this translates to a price for solar PV generation of around 8.8 c/kWh (excl. GST).

This is slightly higher than the typically 7-8 c/kWh that most retailers pay for solar PV exported by householders. Does this mean that these retailers are under-paying for the excess solar power they purchase from householders?

It is unclear whether this is the case as there are a couple of additional factors to take into consideration before working out an appropriate export tariff.

Firstly, the shape used to work out the appropriate weightedaverage price should be the *export profile*, not the shape of solar generation. Due to the interaction of residential demand and solar generation, a typical export profile is even more heavily weighted (in proportional terms) to summer than winter. Indicative analysis using the model described earlier suggests that an appropriate export tariff should be between 90% to 95% of a tariff which was weighted by the entire solar output.

Secondly, as discussed earlier in section 4.4.1, the retail operating costs for customers that export solar are likely to be higher than other customers, and this may be reflected in a slightly lower export tariff to recover such costs.

All-in-all it is unclear whether a 7-8 c/kWh export tariff is an appropriate price or whether something closer to 8.5 c/kWh may be closer to the real value of solar output.

The last point to make is that the above analysis is based on current levels of solar penetration. If solar PV output grows to levels where it accounts for a significant proportion of annual demand, the generation-weighted average value of solar output is likely to significantly decline.

www.concept.co.nz

concept

Appendix B sets out analysis which shows that this is due to high levels of solar penetration exacerbating the periods of relative generation surplus where additional generation is not of much value (e.g. summer afternoons), versus the periods of relative generation scarcity (e.g. cold winter evenings). This is a similar phenomenon to the progressively declining value of wind generation with progressively increasing wind penetration. The analysis in Appendix B estimates that if 10% of demand were met by solar, the \$/MWh value of such solar in terms of avoided grid generation costs could be approximately 70% of the value based on current solar penetration levels.

The last point to note is that it is not clear that the system could operate securely were *instantaneous* solar output to reach relatively high levels (e.g. 40% of demand or above) – noting that Appendix B demonstrates that solar penetration of 10% of annual demand could result in instantaneous solar output reaching levels of 77% of the total at times of low demand. On the one hand, the reduced grid inertia will make it extremely challenging to manage the system in the event of the unexpected loss of another large generator, or the HVDC and prevent subsequent frequency collapse. This could require the procurement of more instantaneous reserves.

On the other hand, at times of high solar output it is likely that the output of the largest generation unit operating will be less, and therefore require less instantaneous reserves to manage – although the HVDC could still be operating at relatively high transfer levels.

However, consideration of such matters is a study in its own right, and not considered further in this report.

4.4.4 Avoided CO₂ costs due to solar PV

With regards to the CO₂ component of retail tariffs, we have examined how the effective long-term emissions intensity of electricity production varies by time of day and year (using the same models as the first report in this study).

This analysis shows that electricity uses types which are heavily concentrated at times of system demand peak (e.g. electricity space heating) will result in a significant amount of emissions, as such demand is predominantly met by fossil-fuelled stations, whereas baseload demand which is flat across the year will have a relative low emissions intensity, because it is predominantly met by lowemission options such as geothermal and wind.

Figure 48 shows the demand-weighted-average marginal emissions intensity of different demand profiles, noting that these represent the outcomes expected over the longer run for modest increments in each type of electricity demand.





Figure 48: Demand-weighted average marginal emission intensity

For solar PV, the appropriate emissions intensity relates to what other generation is being displaced. The previous report⁸⁰ in this study identified that, while in the short term solar PV is likely to displace fossil, in the long-term it is likely to be displacing wind and geothermal that would otherwise be built, and in the very long-term with high levels of solar penetration may actually result in in increased need for fossil generation to perform seasonal firming.

This is shown in Figure 49 which is taken from this previous report. As well as the avoided (or in the long-term, increased) electricity

80

sector ('e sector') emissions impacts, this also shows the embodied emissions associated with manufacturing solar PV panels. For the purposes of the value of solar PV in terms of electricity sales, these embodied emissions impacts should be excluded.

Figure 49: Lifetime emissions impact of PV - Central scenario



Given this changing profile of electricity sector emissions impacts of PV, the value used for this illustrative analysis is the mid-way point between the 2016 and 2021 numbers shown above – i.e. 0.12 $kgCO_2/kWh$.

http://www.concept.co.nz/uploads/2/5/5/4/25542442/new technologies emiss ions report final.pdf



4.4.5 Total value of solar PV

Figure 50 shows the current residential variable tariffs shown in Figure 43 (i.e. the reward to solar PV for self-consumed PV output) and compares them with the assessment of the value of solar to New Zealand, based on the analysis presented in the previous subsections.

Figure 50: Comparison of current variable tariffs with assessed value to New Zealand of solar PV generation



It shows that a consumer on a low-user uncontrolled tariff will be rewarded for their solar at a rate that is almost three times its true value to New Zealand. This is almost entirely due to inappropriately avoiding paying for network and retail costs, given that the Energy + CO_2 component of a residential tariff is broadly equivalent to the Energy + CO_2 value of solar generation – at least for relatively low levels of solar penetration. This is also illustrated in Figure 51. It compares the current average retail tariff with the costs of supplying electricity at the different times of day and year, and illustrates how the value of solar to New Zealand has been assessed.

Figure 51: Comparison of solar PV output at different times, with incremental system value at such times



The majority of solar PV output is during summer day times, with another third in winter day times, and virtually none at other times. The solar generation-weighted average value of the avoided costs of grid generation at such times results in the 'cost-reflective value of



solar PV' shown as a dotted blue line. This is significantly lower than the current flat tariff.⁸¹

Box 1: Thought experiment – is rooftop solar PV being rewarded properly?

To test the analysis summarised in Figure 50 - i.e. is solar PV being over-paid - consider a hypothetical example: two identical 3kW solar panels, "A" and "B", that are located 10 metres apart and each separately connected into the low voltage distribution network.





Electrically, they make an identical contribution to avoiding:

- grid-scale generation costs: i.e. displacing a lot during summer days, much less during winter days, and none during nights; and
- transmission and distribution 'lines' costs: i.e. <u>no</u> impact on reducing the need for lines networks – and potentially *increasing* costs if they are installed in an LV network with a lot of solar PV.

Further, neither is reducing the amount of retail cost-to-serve costs (i.e. metering, billing, call centres, advertising, etc.).

The question is: "What should each of these panels be paid?"

The right answer from New Zealand's perspective is that they should each be paid an identical amount, being the value of the costs they avoid for New Zealand, i.e.: avoided grid generation (taking into account any avoided network losses) – less an amount to take account of any network cost increases they impose.

This is the basis on which other generation (large transmissionconnected, or small distribution-connected) is paid, and is a framework which ensures that only the cheapest generation (taking into account any costs they impose on the system) is built and used (i.e. dispatched).

However, at the moment in our hypothetical example, panel A is effectively getting paid close to two-and-a-half times the amount of

significantly reduces the benefits to consumers from investing in home insulation, efficient lighting, or non-electric forms of space heating (e.g. log-burners or gas heating).

⁸¹ As an aside, this over-payment to solar PV is the reverse of what is happening to other energy technologies whose consumption pattern is heavily dominated by winter peak periods. For example, the demand-weighted value of lighting and space heating is much higher than the value reflected in a current flat tariff. This



panel B – some \$9,000 extra over the life of the panel in present value terms.

Why is this?

As you will have probably guessed, and as Figure 53 reveals, it is purely because panel A is sitting on a householder's roof and is located behind the household's meter, whereas panel B is not connected behind a household meter.

Figure 53: Solar PV thought experiment - Part 2



As such, because of the simplistic structure of current domestic electricity prices, panel A is enabling the householder to avoid paying for lines and retail costs, even though the solar panel is not reducing such costs for New Zealand.

4.5 Estimating the overall cost-benefit of solar PV uptake for New Zealand

The assessment of the value of solar PV across the ~1,000 different consumer situations was repeated, but this time from the 'public' perspective of the value of solar to New Zealand. The results of this

were overlaid across the previous results (shown in Figure 41) of the 'private' consumer benefit of solar based on current retail tariffs. This is shown in Figure 54.

Figure 54: Comparison of distribution of private and public net present values of solar PV across different consumer situations



This analysis indicates that:

- if consumer decisions are based on existing electricity tariff structures, uptake of PV is likely to grow strongly over the next decade, because increasing number of consumers will see financial rewards from installing PV (i.e. private benefits are positive)
- but if decisions are based on underlying true benefits to New Zealand, PV uptake is not expected to be economic in most situations for many years.



Modelling was undertaken which simulated progressive uptake of solar PV based on the private cost-benefit to consumers under current tariff structures. This uptake was assumed to follow the classic 's-curve' with initial slow uptake, a period of rapid uptake as technology costs fall and there is wide recognition of potential private benefits, and then a reduction in the rate of uptake beyond a penetration level of about 40%.

In addition, some households are unlikely to be suitable for solar PV due to factors such as:

- Property type (i.e. apartments were not considered to be suitable)
- Roof orientation or shading
- Tenant / landlord barriers to technology uptake⁸².

We have assumed these factors collectively reduce the uptake ceiling to 65% of all households. The profile of the simulated uptake is shown in Figure 55.



Figure 55: Modelled uptake of solar PV assuming continuation of current tariff structures

The public net present value was assessed for each modelled installation throughout this time series. This took account of:

- Projected declines in the cost of solar PV.
- Changes in the wholesale value of PV with increasing solar PV penetration.

Due to lack of data, it did not take into account any potential increases in network costs associated with high levels of solar PV penetration.

would incur the cost – and not feel confident they could recover such cost through higher rents.

⁸² This type of barrier is well known to exist for other energy technologies such as home insulation, where the tenant would enjoy the benefit, but the landlord



The resultant net present value of such inefficient technology uptake over the 20-year period was estimated to be a net *cost* to New Zealand of \$1.8bn.

There is a significant range of inherent uncertainty over the rates of uptake. Accordingly, it is likely that the costs could be \pm \$0.8bn from this value.

The \$1.8bn estimate is a similar order of magnitude to an estimate compiled by NZIER which stated "*The cost of this artificially high level of investment [in solar PV] is between \$2.7 billion and \$5.0 billion dollars (discounted present value).*"⁸³

This \$1.8bn value reflects how much more New Zealand would spend on meeting its electricity needs via solar panels, rather than from grid generation.

Figure 56 illustrates the underlying reason for this finding. It shows the annualised cost of power on a like-for-like basis for four potential new generation options for New Zealand: three grid-connected technologies⁸⁴ (wind, geothermal, and combined-cycle-gas turbines), and rooftop solar PV. Each is assessed solely on the relative differences in the cost of producing electricity delivered t the point of consumption (including the emissions impacts captured via carbon charges).

Because none of the technologies are expected to avoid or reduce the need for transmission and distribution to be built, there is no difference ascribed to network costs. However, rooftop solar PV does have the benefit (albeit very small) of avoiding losses incurred from transporting electricity across such networks.

Figure 56: Cost comparison for new generation technologies⁸⁵



Figure 56 shows the direct costs of such technologies (capital & operating costs, fuel, and CO_2) for electricity generated and

⁸³ "Effects of distribution charges on household investment in solar", NZIER report to the Electricity Authority, 30 September 2015

 ⁸⁴ Hydro is not included in this comparison because there are not many significant new hydro schemes that are likely to be able to receive environmental consents.
⁸⁵ The levelised cost of energy (LCOE) captures all costs to produce electricity (capital and operating), and spreads them evenly over the expected annual kWh

of generation for each technology to give a \$/kWh measure. This allows like-forlike comparisons. FOM = Fixed operating & maintenance, VOM = Variable operating & maintenance.

A range of CO_2 prices has been used to reflect the difference between the current low CO_2 prices faced by fossil generators, and the higher values which are more likely to reflect the true cost of CO_2 emissions to society.



delivered to a point of consumption. However, it ignores likely wider system costs which are likely to progressively increase for high levels of penetration for some technologies:

- backup generation for periods when the generator may not be operating, for less firm generation such as PV and wind
- distribution network reinforcement costs to cope with reverse power flows with high levels of solar PV.

Figure 56 shows that rooftop solar PV is currently approximately \$0.125/kWh more expensive than wind and geothermal. When this \$0.125/kWh is multiplied by the generation from a typical 4kW solar panel over a 20-year life, this results in a present value of approximately \$7,150. This \$7,150 represents a cost to New Zealand from an inefficient technology choice – building solar, when we could have built cheaper renewables such as wind and geothermal.

If this \$7,150 is multiplied by the estimated number of households for whom solar PV could be economic by 2026 based on current tariff structures (estimated to be 1/4 of all households), this gives a total cost of \$3.0 bn.

This is larger than the \$1.8bn reported above because the more detailed modelling exercise took account of projected reductions in the cost of solar PV, and likely delays in the uptake of solar PV after it starts to appear economic for consumers (based on current tariff structures), whereas this illustrative calculation has not. Nonetheless, it is a similar order of magnitude and illustrates how New Zealand may incur significant costs from consumers making inefficient technology choices.

The third report in this study will address the potential social issues associated with these increased costs being shifted onto non-PV owning households.

Similar outcomes are also occurring from consumers facing the wrong price signal in relation to other energy choices (e.g. not investing as much as they should in home insulation, efficient lighting, non-electric heating (e.g. log burners or gas-fired), or smart appliances with load control capabilities). As with inefficient solar-PV uptake, these inefficient energy technology choices will not only be increasing New Zealand's overall energy costs, but will have equity impacts associated with consumers with relatively peaky demand being cross-subsidised by those with flatter demand.

What about larger-scale solar PV?

Overseas experience indicates that large-scale (hundreds of kWs to multi-MW) solar installations – e.g. on a large warehouse roof, or as a dedicated solar farm – are estimated to result in a \$/kWh cost of solar PV which is approximately one-half to two-thirds the cost of residential rooftop solar systems.

This is because of the significant economies of scale of solar – particularly with respect to installation costs – and the fact that large-scale solar installations are likely to be better able to maximise the solar yield from optimal siting and the like.

As Figure 57 shows (which is the same as Figure 56, but with utilityscale solar included), even with such lower costs of production, large scale solar is still approximately 45% more expensive than other forms of renewable generation. Accordingly, New Zealand would be better off from investing to meet its electricity requirements in these cheaper form of renewables.



Figure 57: Cost comparison for new generation technologies - including utility-scale solar



However, with solar expected to continue to enjoy greater rates of cost reduction over the next couple of decades than wind or geothermal, it is possible that large-scale solar could become competitive with these other renewable technologies at some point.

At that time, New Zealand would be better served to meet some⁸⁶ proportion of its generation requirements from large-scale solar than large-scale wind or geothermal.

The last point to note on this is that such genuinely economic solar is a grid-based technology.

This is consistent with our view that the electricity grid is a significant enabler of renewable generation – allowing:

- Renewable technology to be built where it is cheapest (and at a scale where it is cheapest) and transported to end consumers;
- The diversity benefits from having many geographically dispersed renewable generators of different types (hydro, wind, solar, geothermal) which will significantly reduce the volatility in output from individual renewable generators.

The fact that large-scale solar is cheaper than rooftop solar, and yet the latter is being installed, is indicative of the current pricing structure misalignments. These encourage consumers to choose an option which appears attractive to them, but has higher overall costs to New Zealand.

Remote rural situations

The preceding analysis focuses on grid connected PV systems, and identified a net economic cost arising under current electricity price structures in many situations.

However, an area where PV may offer net economic benefits is in some off-grid applications. For example, for some rural customers, it may be lower cost to implement off-grid solutions when existing lines serving few connections need an upgrade or replacement. To

which can be difficult for the system to manage, even at relatively low overall penetrations such as 5-10% of total generation.

 $^{^{86}}$ As discussed in Appendix B, solar penetration will also be affected by concentrated nature of solar generation – i.e. it comes in concentrated 'lumps'



obtain a high degree of high reliability, off-grid solutions could include a combination of solar PV, batteries, and back-up diesel.

However, again, these benefits are unlikely to be fully realised unless electricity price structures are more closely aligned with underlying costs.


5 Batteries and other storage technologies

5.1 Battery storage – cost-effectiveness

5.1.1 The costs of batteries

As shown in Figure 58 below, battery costs have fallen significantly and are expected to continue to do so as global capacity increases.

Figure 58: Historical and projected fall in battery costs (US\$/kWh of storage)



Source: Bloomberg New Energy Finance

While a large part of this growth is for the provision of batteries for electric vehicles, batteries are increasingly being installed for 'static' energy applications:

- By households wishing to balance their solar generation with their demand
- By utilities using batteries as an alternative to networks and/or generation to meet peak demand
- As a means of enabling some consumers to go completely 'off-grid'.

Costs are generally expressed in \$ per kWh of storage capacity – referred to a kWh_stor in this report. A residential-scale battery with a capacity of approximately 8 kWh is currently expected to have an installed cost of approximately \$9,400, incl. GST – i.e. \$1,150/kWh_stor.

Utility-scale batteries (i.e. of a scale of 500 kWh to 10 MWh) enjoy considerable economies of scale relative to residential-scale batteries. As a result, the installed \$/kWh_stor cost of a utility-scale battery is estimated to be approximately [60%-80%] of that of a residential-scale battery.

There are understood to be relatively low ongoing operation & maintenance costs. The life of the battery is typically limited by the number of 'fill-release' cycles⁸⁷ it performs before its internal chemistry degrades to the point where it is economic to be replaced.

⁸⁷ Battery chemistries vary, and in reality their economic life is also dependent on cycle depth, temperature, and other factors. However, the number of charge/discharge cycles is the key metric for most lithium ion batteries.



Depending on how many cycles are performed each year, this could result in batteries lasting anywhere between 10 and 25 years. A central value of 15 years has been used for the cost-benefit analysis in this study.

5.1.2 Value of batteries

Batteries and other storage technologies allow electricity to be stored at a time of relative surplus, in order to be released at a time of relative scarcity. This temporal arbitrage can be valuable if there are significant differences in the costs of electricity supply at these different times.

Figure 59 illustrates this pattern of operation and its effect on net demand.

Figure 59: Illustration of operation of storage batteries



Network benefits of batteries

One of the outcomes that is immediately apparent from Figure 59 is that overall system peak demand is reduced from operation of the batteries – in this case, reducing the extent of winter evening peak demand.

This is particularly valuable for reducing network costs, as around 50%+ of network costs are estimated in the long-run to be associated with providing capacity to meet network demand.⁸⁸ Appendix C sets

outcomes (i.e. > 10-15 years). In the short-run (i.e. <5-10 years) network costs are increasingly fixed.

⁸⁸ For example, Orion has stated that "approximately 50% of our distribution costs are directly depending on the coincident peak loading". [p21 of 1 April 2015 *Methodology for deriving delivery prices*]. This is understood to be long-run



out analysis which suggests that the network value of reduced peak demand could be between \$30 and \$300/kW/year, depending on a range of factors.

The extent to which a battery of a given kWh storage size will be able to reduce peak kW demand is a function of:

- Its maximum speed of discharge and hence its peak kW output. Thus a 10 kWh battery which takes two hours to discharge could deliver a 5 kW output, whereas a battery which could discharge in one hour could deliver a 10 kW output.
- The length of time required to operate at a sustained output in order to deliver additional peak demand reduction. Thus, some networks already control load to an extent that they have achieved a relatively 'flat' demand curve during the daytime for peak demand days. To deliver additional demand reduction on such days may require sustained battery operation of up to 8 hours. Thus, in such a network situation, even if a 10 kWh battery could fully discharge within 1 hour, because it needs to operate over an 8 hour period, its effective kW contribution would be 10 \div 8 = 1.25 kW

It should also be noted that there will be diminishing returns to batteries and other peak management technologies. Thus, a network which has a so-called 'needle-peak' whereby very high peak demand occurs only for a very short time in a day, can manage such peak demand by calling on batteries or other load control technologies for a short period of time. However, if demand is flatter, or gets progressively flatter due to the operation of loadmanagement technologies, the amount of time batteries or other load technologies need to operate during a day to make meaningful further reductions in demand will need to be longer.

Generation benefits of batteries

Figure 59 illustrates that the reduced demand at times of peak is offset by increased demand at off-peak times. Indeed, although it is not readily apparent from looking at Figure 59, overall demand (and hence generation) is *increased* by approximately 0.2% due to the approximately 10% losses incurred from converting the AC power to DC and back again when it is stored in the battery.

However, despite these conversion losses, this shifting of demand can also result in significant generation cost savings from flattening the demand profile. Over the long-term, the 'filling-in' of the troughs will increase the proportion of generation met by less expensive baseload generation. This increase in baseload generation, plus the reduced demand at times of peak, will reduce the need for more expensive mid-merit/peaking generation.

These effects are illustrated in Figure 60 below.





Figure 60: Illustration of the generation impact of storage batteries

The value of such outcomes is complex to evaluate as it depends on the balance of fixed and variable costs between the different types of plant (baseload, mid-merit & peaking), and thus the extent to which baseload plant will increase their generation in the long-term.

However, Concept modelling of the range of possible outcomes suggests a rough rule-of-thumb whereby the long-term value of these altered generation outcomes can be approximated as:

kW peak demand reduction * \$/kW/year carrying cost of peaker * 1.75

The 1.75 factor has been chosen based on an evaluation of the range of modelled outcomes, noting that factor values can range from 1 to 2.5.

Given that the carrying cost of an OCGT peaker is approximately \$145/kW/year (being the capital and annual fixed costs of building and operating an OCGT), this suggests that the generation value of batteries could be worth approximately \$250/kW/year in the long term.

Such value will only be realised if there is a need for additional capacity to meet demand growth. If the system is in a state of relative over-capacity, then the majority of the generation benefits of reducing peak demand will be deferred until such time as demand growth and/or retirement of existing generation capacity brings the supply / demand situation more into balance.

The outcomes illustrated above are for daily cycling of batteries. In theory, it would be possible to have some batteries which were used to perform seasonal cycling – filling-up once in the summer to release again once in the winter. This would enable an even greater amount of generation to be undertaken by cheaper baseload plant.

However, this is unlikely to be cost-effective in the foreseeable future. For example, if a battery is only just cost-effective to deliver benefits of daily arbitrage over the 365 days of the year, it will need to be much cheaper in order to be cost-effective for once-a-year seasonal cycling.



Other possible system benefits of batteries

Batteries may also be able to provide system management benefits in terms of frequency management. However, no attempt has been undertaken to quantify the scale of such additional value.⁸⁹

5.1.3 Summary cost-benefit of batteries

Over the long-term, from a total system perspective, the temporal arbitrage of batteries should enable a reduction in the amount of peak network and generation capacity required, and enable a greater proportion of generation to come from cheaper baseload plant. Offsetting that value is the up-front costs of purchasing and installing the batteries.

It is difficult to quantify the net benefit, but it could run into the hundreds of millions of dollars or more over the next 20 years.

Figure 61 below presents a summary evaluation of the current and ten-year-in-the-future estimated cost-benefit of residential batteries:



Figure 61: Assessment of current and ten-years-in-the future system cost-benefit of residential batteries

As can be seen, a significant range of values has been ascribed to both the costs and the value of batteries.

The range of costs is due to uncertainty over the costs of such technologies, given that they are still in their infancy, and with few examples in New Zealand.

likely to already be discharging at times of capacity scarcity to avoid network and generation costs. (* The two frequency management ancillary services are: frequency keeping and instantaneous reserve.)

⁸⁹ Given that the principal cost driver of the two ancillary services^{*} used for frequency management is the cost of providing capacity to provide such services at times of capacity scarcity, it is potentially the case that there may not be much additional value from batteries for delivering such services given that they are



The range in values is because:

- There is likely to be significant variation in network values due to variation in whether the local network (distribution and/or transmission) is likely to need to invest to meet peak demand in the foreseeable future. Further,
 - there is likely to be significant inherent variation in the \$/kW cost of network expansion depending on circumstances (e.g. rural vs urban);
 - there is likely to be variation in how long batteries would need to operate on a sustained basis during a day to deliver the peak kW benefits; and
 - there is considerable uncertainty as to the appropriate basis on which to value such expansion costs
- There is uncertainty over when the New Zealand system will move into a situation of requiring additional generation capacity, and uncertainty of the net value of increased baseload-type generation minus reduced peaking generation.

While it appears that residential batteries are unlikely to be costeffective at present in most situations, Figure 61 *appears* to indicate that they could be in the future.

The italicisation of the word appears, is because even when the costs of residential scale batteries have dropped significantly, it is not clear

that they would be least-cost solutions for meeting our electricity requirements for two reasons:

- Firstly, as Figure 62 highlights, there are significant economies of scale with batteries, and a few larger, utility-owned batteries located at strategic points around a distribution network could deliver exactly the same (if not slightly more) electricity system benefits⁹⁰ as would be achieved from having large numbers of smaller consumer batteries – but at lower cost.
- Secondly, utility-scale batteries may themselves be more expensive than an even-cheaper source of peak-demand-lopping batteries – namely the batteries in electric vehicles (EVs). These too have the potential to inject power back into the grid at times of peak demand. However, the *incremental* cost of such batteries could be much lower than static residential or utility-scale batteries. This is because EV batteries would largely already be being paid for to provide another service – i.e. transport.

there is the ability to relocate utility batteries over time to parts of the network with greatest need.

⁹⁰ This is due to multiple effects such as load diversity (which means that a smaller utility battery is required compared to distributed consumer batteries), that the utility will seek to reduce real costs (i.e. not simply minimise consumer costs), and



Figure 62: Comparison of cost-benefit of residential and utility-scale batteries



What this points to is the need to ensure that price signals to consumers, and incentives on utility companies, are appropriately designed so that such parties invest in technologies that are genuinely least cost. Tariff design is going to be particularly challenging in this respect, particularly in terms of reflecting the nature and cost of peak demand outcomes taking account of such factors as:

- The extent of existing surplus capacity (either for an individual network, or for national generation), taking into account existing price-driven load control.
- The nature and extent of existing load control, and thus the duration required, and value of, additional load control to manage peak demand.⁹¹

5.2 Storage + PV solar – cost effectiveness for consumers

As indicated in the previous Chapter, the financial attractiveness of solar PV to consumers is strongly influenced by the proportion of solar power they export.

If consumers could store more electricity at times when they have surplus solar power and use it later, they would increase the proportion of solar power that is self-consumed, capturing a higher reward (albeit unduly so) under current pricing structures.

Two main storage technologies are available. Each has different costs and characteristics:

• Lithium-ion batteries (e.g. the Tesla Powerwall). The current cost of a household-scale battery with an 8 kWh storage capacity is approximately \$9,400 (including installation and GST). As well as the up-front capital cost, about 10% of the electricity is lost when

curve gets progressively flatter, additional load control will need to operate for longer to deliver incremental peak demand benefits.

⁹¹ One aspect of this is that there are diminishing returns from additional load control. Thus the first MW of load control to shave the top few hours of peak demand off the load duration curve are very valuable. However, as the demand



converting the power from AC to DC and back again when storing it in the battery.

Hot water cylinders, whereby the excess solar electricity is 'stored' in the form of hot water, which can be used later. If a house has an existing hot water cylinder, the only cost is a diverter⁹² – estimated to be \$900 incl. GST. If a new hot water cylinder is required, this can add an additional \$2,300. The effective amount of electricity which can be stored ranges between 7 to 16 kWh, depending on the size of the cylinder.

Concept modelled the effect of using such storage technologies to store surplus solar PV power for the same ~1,000 consumer situations described previously for the solar-only evaluation.

As Figure 63 below shows, storage can result in a material amount of solar PV power being used to offset residential consumption which would otherwise have been exported.

Figure 63: Proportion of solar PV no-longer exported due to storage

A) 8 kWh Battery storage



⁹² A diverter is a generic name for an electronic controller that can 'divert' PV generation into your hot water cylinder instead of exporting it to the grid.



B) Hot water storage



Thus, on average, for a household with a 4 kW solar panel, the proportion of PV exported drops from 66% to 34% with storage.

Figure 64 shows the overall financial impact for consumers of storage + solar for households with a 4kW panel.

*Figure 64: Current financial impact of storage + 4kW solar PV based on current residential tariffs*⁹³



Figure 65 shows the specific cost-benefit of storage, if the household has already installed solar PV (i.e. it examines only the incremental costs and benefits of storage).

⁹³ Although the impact on the altered proportion of export is roughly the same for batteries and hot water storage, the value is different due to the fact that in many network areas, hot water is charged on a specific hot water tariff.



Figure 65: Average cost-benefit of storage for households with 4kW solar panels



Battery Hot water cylinder

The relatively high cost of a lithium-ion battery outweighs the value of the additional revenue – yielding negative overall result. However, for a consumer that has *already installed* solar PV, adding a diverter to their existing hot water cylinder storage is cost effective. However, as Figure 64 shows, if they don't already have solar PV, installing solar PV and a diverter is still not cost-effective on average, relative to grid-supplied power.⁹⁴

However, with projected reductions in the cost of solar PV, it is likely that solar + hot water storage solutions will become cost-effective for many consumers sooner than solar-only installations.

5.3 Storage + PV solar - cost effectiveness for New Zealand

The question is, might solar + storage be economic from a whole-of-New Zealand perspective?

For this, we have used the same framework as applied in section 4.4 to consider the public cost-benefit of stand-alone solar installations.

Firstly, there is no reason to expect solar + storage to materially reduce retail operating costs. However, as Figure 66 shows, solar + storage can reduce consumers' net electricity demand at times of system peaks – the critical periods which drive peak network and generation costs.

⁹⁴ And if a household were to need to spend an additional \$2,300 on a hot water cylinder, the hot water cylinder option would outweigh the value of the additional revenue.



Figure 66: Average modelled reduction in household's net demand during top 2% of system demand periods



This could be very valuable from a New Zealand cost-benefit perspective. However, close examination of the model results shows that during the top 2% of demand periods, the storage technologies were, on average, only releasing energy at about approximately 20% of their full capacity.

⁹⁵ That said, with very high solar uptake the period of greatest surplus may change to the middle of the day, especially in sunny summer days. This is discussed in section 4.4.3.

In a large number of instances this is due to a lack of surplus solar prior to these times of peak demand (which are often during periods of several days of cold and cloudy weather). Hence, the storage cannot be filled during the middle of the day in order to be released in the peak evening periods.

If on these cloudy days, filling storage with solar is supplemented with filling it with off-peak grid electricity, the extra storage available to be used at times of peak can result in significant further reductions in peak demand.

However, this points to a deeper truth: it is not solar + storage that is making these system cost savings – it is the storage component through its ability to effectively move 'cheap' power from times of surplus to be released at times of relative scarcity.

Operating storage technologies in combination with solar does not make this shifting function any more effective. Indeed, if a solar consumer operates storage to minimise their exports, the resulting outcome will be <u>less</u> effective at minimising New Zealand's system costs for two reasons:

- Firstly, instead of filling up the storage at times of greatest wholeof-system surplus (i.e. overnight when the ratio of NZ's renewable supply to grid demand is highest), a significant amount of storage will be filled up during the day at times of peak solar output.⁹⁵
- Secondly, although most consumers' demand patterns tend to reflect whole-of-system demand, there is significant variation



among individual consumers. Thus storage which is operated to release power at times to suit an individual consumer's demand profile will, across the wide variety of consumers, be less effective at reducing system peaks than if storage were operated to minimise New Zealand's overall system peaks.

Taken together, these effects mean that storage operated to minimise individual consumers' solar export and demand profile won't flatten New Zealand's demand curve as much as could be achieved. This will:

- Make peak demand and by extension, network costs higher than could be achieved; and
- Limit the extent to which New Zealand's power could be generated by cheaper baseload (and in New Zealand's case, renewable) generators, instead of more expensive (and fossil-fuelled) peaking generators.

This last point was highlighted in the first report in this study on emissions effects from new technology uptake. This showed that operating storage batteries to minimise individual consumers' export profiles, rather than optimising New Zealand's overall renewables position (i.e. taking into account hydro, wind and geothermal) would roughly halve the likely emissions benefit of storage batteries in terms of displacing peaking fossil generation.

Given that operating storage to manage an individual consumer's solar export and demand profile will make it less effective at managing overall system costs, the remainder of this section on storage consider the economics of storage <u>independent</u> to that of solar PV.



Appendix A. Background information on vehicles

Travel patterns

As shown in Figure 67, the average distance travelled by a light passenger vehicle in 2014 was approximately 11,000 km.

Figure 67: Light passenger travel per vehicle



Source: Concept analysis using MoT data

However, this average figure hides a considerable range of average annual distances travelled by passenger vehicles. One example of this is shown in Figure 68 below, which shows that new vehicles are driven a lot further than old vehicles, and also that new larger-engine vehicles tend to be driven further than new smaller engine vehicles (although this trend reverses for very old vehicles).

Figure 68: Light vehicle passenger travel in 2014, by age and motor capacity of vehicle



For considering appropriate VKT values for EV purchases versus ICE purchases it is worth noting that vehicles enter the New Zealand fleet via two channels:

- New Zealand new which accounted for 47% of vehicles entering the New Zealand fleet in 2014.
- Second-hand ('used') typically from Japan which accounted for 53% of vehicles entering the New Zealand fleet in 2014.The average age of used vehicles entering the fleet is 8 years.

Accordingly, based on Figure 68, an appropriate VKT for considering the economics of new vehicles would be 16 kVKT, and for used vehicles it would be 12 kVKT.



BEV range anxiety

The range of a mid-range BEV with a full battery is only approximately 100km, compared with 500-800km for an ICE with a full tank of petrol. Further, while it may only take 1-2 minutes to re-fill a tank of petrol, an empty BEV battery can take approximately 5 hours to re-charge at home, and still take 30 minutes to re-charge to 80% at a so-called fast charging station. Plus, while petrol stations are ubiquitous around the country, there are currently fewer fast charging stations.

This dynamic can create so-called 'range anxiety' for consumers considering purchasing a BEV – i.e. concern that they may run-out of battery, and not be close to a charging station, plus incur longer times to re-charge.

Coupled with higher up-front capital costs, range anxiety is understood to be a barrier to purchase of BEVs.

That said, range anxiety could start to diminish as a barrier for BEV purchases:

- For households with two vehicles, a BEV could be the principal car for the smaller-distance, 'around town' journeys which, as Figure 69 below shows, account for the vast majority of journeys;
- The number of charging stations around the country is starting to grow; and
- The range of new BEVs is starting to improve, with a number of vehicle manufacturers (including Tesla, Chevrolet and Nissan) are planning to sell long-range (i.e. 250km+) EVs for the mid-range market in the next couple of years.

Figure 69: Daily travel distance by vehicle type

٠



Source: Data sourced from study by Centre for Advanced Engineering, University of Canterbury

This range anxiety doesn't apply to PHEVs because of their ability to operate on petrol.

EV charging patterns

Figure 70 illustrates the number of light vehicles on the road at different times of the day, differentiating between whether the destination is the vehicle owner's home, or another destination (e.g. work). This shows that there are clear morning and evening peaks to travel times, with the evening peak dominated by journeys home.



Figure 70: Light passenger vehicles on the road at different times of the day



Source: Concept analysis using MoT household travel survey data

Based on this pattern of travel, it is likely that, *absent any price signals*, the time when the greatest number of vehicles would be plugged into the grid to be charged would be in the early evening, when people return home. As the analysis in section 2 in the main report sets out, this is also the time of greatest cost in meeting demand.

However, Figure 70 also shows that there is a considerable down time during the night (between 10pm and 6 am) when vehicles are not used. This would be more than enough time to charge the majority of vehicles given that, as shown in Figure 69, the majority of daily distances travelled are relatively short.



Appendix B. Analysis of the generation value of solar at high penetration levels

Section 4.4.3 sets out analysis of the likely value of the grid generation which solar displaces. However, this analysis is largely based on the likely interaction with grid generation at the current low levels of solar penetration.

If solar PV output grows to levels where it accounts for a significant proportion of annual demand, the generation-weighted average value of solar output in terms of the generation which it displaces is likely to significantly decline.

This is because solar generation is relatively concentrated at specific times of the day and year. With large amounts of solar uptake, the difference between periods of solar surplus and no solar scarcity will become very large. This will tend to depress wholesale prices at times of high solar generation, and vice versa. This phenomenon is already occurring in markets with high solar penetration such as Australia.

An example of this can also be seen in New Zealand with wind generation. Figure 71 plots the price outcomes achieved by the Tararua wind farm for each year from 2001 through to 2015. The y-axis plots the ratio of the generation-weighted average price achieved by the Tararua wind farm to the time-weighted average price for that year, while the x-axis shows the proportion of total wind on the New Zealand system.

Figure 71: Ratio of generation-weighted to time-weighted price for generation from the Tararua wind farm over the period 2001 to 2015



In the early years of the Tararua wind farm when there were few other wind farms in New Zealand, (i.e. to the left of graph) it achieved a GWA/TWA ratio which was approximately 95%. It was not 100% or above because wind tends to have a slight counterseasonal profile to demand. However, as time has progressed and more wind has come onto the system (moving to the right of the graph), the incidences of price falls during windy days when large amounts of wind farms are all generating at once has increased. This has resulted in the GWA/TWA falling to about 85%.



Concept has undertaken analysis to estimate the extent to which similar outcomes may occur for large amounts of solar PV uptake. The results of this are shown in Figure 72.

Figure 72: Estimated change in solar PV GWA/TWA due to increased solar penetration



As can be seen in Figure 73, which combines both the solar and wind analysis, solar PV starts from a position of achieving a more favourable GWAP/TWAP of approximately 106% (due to its favourable day/night profile outweighing its unfavourable summer/winter profile), but this falls more rapidly with increased penetration than for wind.



Figure 73: Change in GWAP/TWAP with increased grid penetration for wind and solar

This is because solar output is much more concentrated than wind (i.e. compared to wind, solar PV has a much lower capacity factor, but much higher correlation between PV sites). As such, it tends to have a greater price depressing effect on wholesale prices when it is operating, for an equivalent amount of annual generation.

This is illustrated in Table 2 which presents a simple back-of-theenvelope calculation to estimate the potential maximum instantaneous output of wind or solar for an equivalent share of annual generation.

www.concept.co.nz



Table 2: Illustration of impact of high penetration of wind versussolar

Total NZ demand (GWh)

40,000

	Wind	Solar
% of annual NZ demand	10%	10%
Generation (GWh)	4,000	4,000
Capacity factor	42 %	14.50%
Installed capacity (MW)	1,090	3,150
Min NZ demand at time of max solar / wind output (MW)	3,150	4,110
Time of such potential outcomes	Summer night	Summer weekend 1pm
Max wind/solar output as % of min demand	35%	77%

Wind vs Solar back of envelope.xlsm

Because the capacity factor of solar in New Zealand is 14.5% compared to wind's 42%, the installed MW of solar in order to deliver 10% of New Zealand's annual energy requirements is 2.9 times greater than for wind (i.e. 3,150 MW ÷ 1,090 MW).

⁹⁶ The contrast is potentially even greater than suggested by this simple back-ofthe-envelope calculation due to the fact that the assumption that it is very windy For a total annual demand of 40,000 GWh, the minimum half-hourly demand which can occur is estimated to be approximately 3,150 MW which is likely to be during a summer night. If at this time it were windy throughout the country such that all wind farms were operating at full output, this would mean that wind would be accounting for approximately 35% of all generation at that time.

For solar, the time of maximum output is approximately 1pm in the summer. Minimum demand at such times will be during a weekend and likely to be of the order of 4,110 MW. If it were sunny throughout New Zealand at that time such that all PV panels were operating at full output, solar generation would be accounting for approximately 77% of all generation at that time.

Because solar comes in more concentrated than wind (i.e. compared to wind, solar PV has a much lower capacity factor, but much higher correlation between PV sites), it is likely to cause more significant situations of surplus (with associated price collapses) than wind.⁹⁶

Figure 74 shows the output of a simulation model that examines the effect of high solar uptake on grid generation.

throughout the entire country at a given moment in time is much less likely than it being sunny throughout the entire country at the same time.



Figure 74: Simulated market outcomes for 2036 with average annual solar generation = 9.1% of total generation



At times of highest demand (to the left of the graph) – which is also when prices are highest – solar makes no contribution. However, a significant proportion of solar PV's generation is concentrated at times when the post-solar residual grid demand is lowest (at the right of the graph) – and when prices will also be lowest.

Indeed, at times of such high solar output, it is likely that wholesale prices will drop to zero as there will be large amounts of must-run generation – the combined total of which can exceed total national

demand. Thus, based on current installed capacity of other types of plant:

- A significant proportion of hydro is effectively 'run-of-river' and is likely to operate (or spill), plus the non-run-of-river hydro must always operate at a certain minimum level to meet minimum flow requirements (i.e. to prevent rivers running too low). The scale of this must-run hydro is estimated to be of the order 500 to 1,000 MW
- Wind is likely to be operating at between 200 to 300 MW
- It is likely that there will be around 800 MW of geothermal which is difficult to turn down, because it adversely affects the geothermal reservoir.



Appendix C. Analysis of network costs

With regards to network costs, the operation of batteries has the potential to make very significant impacts on network costs. Thus, batteries can reliably fill-up overnight and release during periods of peak demand. Over the long-term, this type of operation will reduce the extent of peak demand growth on the system. Given that, as set out in section 4.4.2, peak demand is the principal driver of network costs, this has the potential to make significant cost savings.

The value of these savings in terms of \$/kWh of battery storage capacity are a function of the following factors:

- The \$/kW/year long-run marginal cost of network expansion to meet peak demand.
- The time when such network expansion would otherwise be required.
- The peak kW output capability of a battery, factored by the duration such output is required in order to reliably reduce peak demand.

Each of these factors is considered in turn.

There is limited published analysis of the LRMC of network expansion in New Zealand, with only one significant example having been identified: Orion's derivation of a 'Long Run Average Incremental Cost' (LRAIC) as part of its development of its network prices.

Accordingly, this Orion example has been supplemented with another estimate using data from Australia. There, distribution companies are required to develop estimates of the LRMC of meeting demand growth as part of developing their network prices.

For mass-market customers, Orion has estimated a distribution network LRAIC of \$101/kVA/year. It also passes on the transmission charge in such a way that this equates to a cost of \$51/kVA/year. This gives a rough estimate of peak-demand-driven network LRMC of approximately \$150/kVA/year.⁹⁷

For comparison, the average of the Australian network companies' distribution LRMC estimates is A\$235/kW/year⁹⁸ (≈ NZ\$260/kW/year). No specific estimate of the Australian transmission LRMC has been found in these pricing documents.

There is significant difference between the Orion and Australian estimates, with the Australian estimates of the distribution LRMC being one-and-a-half times that of Orion's estimate. Part of this may reflect different network circumstances, but other factors are also likely to be relevant including:

• Orion's approach is to take the estimated replacement cost of the entire existing network, and divide those network costs which are

⁹⁷ In some situations, peak demand is expressed on a kW basis, and in other situations it is expressed on a kVA basis. The difference between the two relates to the power factor of the demand. For the purposes of this analysis, the two can be considered to be broadly equivalent. – i.e. $k/kV/year \approx k/kW/year$.

⁹⁸ "Efficiency of Tariffs for Current and Emerging Technologies. A report for the Australian Energy Market Commission", NERA, 21 July 2014



assessed to be driven by peak demand by the quantity of current peak demand.

• The Australian networks' approach is to project forward different levels of peak demand growth over a long period of time, and estimate the different levels of costs that will be incurred to meet such demand growth.

It is outside the scope of this study to determine which approach is most appropriate to assess the 'true' network cost implications of peak demand growth. Accordingly, a range of different cost estimates are used, reflecting this range between the Orion and Australian figures.

These LRMC values need to be factored downwards if a network would not otherwise need to make investment to meet peak demand growth for many years.

A number of networks have significant surplus capacity due to having made recent capacity investments or due to experiencing declining demand on their network. In such situations, the value of reducing peak demand further through the operation of batteries should be discounted down by the number of years until investment would be required.

Accordingly, the range of LRMC values set out above will need to be further extended to take account of the likely range of network situations. In this, it is important to note that in order to value the benefit of batteries, evaluation of the time when the network would otherwise need to have investment to meet peak demand should base such evaluation on demand outcomes if there were <u>no</u> pricedriven load control. To illustrate this, consider a hypothetical example of a network which is undertaking a lot of hot water load control. With such load control the network would not need to make investment to meet peak demand growth for another 20 years. However, if such load control were not to happen, then the time when investment would be required to meet peak demand growth would be brought forward to only five years in the future. For such a network, the LRMC value of avoided network expansion due to batteries should only be discounted by five years rather than twenty years.

As can be seen, these combined factors result in a considerable range for the network value of batteries avoiding peak demand growth.





In order to translate this \$/kW/year value into a value expressed in \$ per kWh of battery storage a factor needs to be applied which reflects the kW output of a battery per kWh of storage.

In this, a central value of 0.3 kW/kWh has been used. This is based on data from Tesla which suggests that a 7 kWh battery can deliver a sustained 2 kW of output to go from full to empty – i.e. 3.5 hours of such output. It is understood that many batteries (including Tesla's) can deliver instantaneous output which is greater than this factor. However, in order to reliably trim system peaks it is likely that firm, sustained output of the order of 3.5 hours in duration is likely to be required.

This results in the following estimate of the annualised value of avoided network investment due to battery storage. This is expressed in \$/kWh_stor/year, where kWh_stor represents the kWh storage 'volume' of a battery.

120 Network LRMC valuation approach 100 80 60 40 40 20 20 0 10 20 ConsumerTech, v12, dam

Figure 75: Value of avoided network costs due to battery storage