Effects of distribution charges on household investment in solar

NZIER report to the Electricity Authority

30 September 2015

About NZIER

NZIER is a specialist consulting firm that uses applied economic research and analysis to provide a wide range of strategic advice to clients in the public and private sectors, throughout New Zealand and Australia, and further afield.

NZIER is also known for its long-established Quarterly Survey of Business Opinion and Quarterly Predictions.

Our aim is to be the premier centre of applied economic research in New Zealand. We pride ourselves on our reputation for independence and delivering quality analysis in the right form, and at the right time, for our clients. We ensure quality through teamwork on individual projects, critical review at internal seminars, and by peer review at various stages through a project by a senior staff member otherwise not involved in the project.

Each year NZIER devotes resources to undertake and make freely available economic research and thinking aimed at promoting a better understanding of New Zealand's important economic challenges.

NZIER was established in 1958.

Authorship

This paper was prepared at NZIER by John Stephenson.

L13 Grant Thornton House, 215 Lambton Quay | PO Box 3479, Wellington 6140
Tel +64 4 472 1880 | econ@nzier.org.nz

Key points

- Investment in solar photovoltaics is likely to be many times larger with high consumption charges than without the high consumption charges.
- The cost of this artificially high level of investment is between $2.7 billion and $5.0 billion dollars (discounted present value).
- Most of the effects of accelerated investment are likely to occur in the next 10 years.
- With high consumption charges, consumers who reduce their use of reticulated electricity will reduce their contribution to network charges. This is irrespective of whether or not the steps they take to reduce consumption also reduce their use of capacity provided by networks that reticulate electricity.
- This is inefficient to the extent that it raises the overall cost of electricity to consumers and stimulates premature investment in solar photovoltaics.
- The retail bills of consumers without solar photovoltaics are likely to rise by around 10% in the next 10 years as a consequence of high consumption charges and accelerated investment in solar photovoltaics.

Contents

Appendices

Figures

Tables

1. Potential effects of consumption charges on investment in solar

This report describes potential effects of consumption based distribution pricing on household investment in solar photovoltaics and the flow-on effects on household electricity bills.

The focus is on the effects of high consumption (kWh) charges. Although other kinds of use-related charges exist, consumption charges represent the majority of use-related distribution charges in New Zealand.[1]

Broadly speaking, high consumption charges increase the attractiveness of investing in solar because they allow consumers to avoid some of the costs of network use. This is inefficient to the extent that costs of service don't decline.

With high consumption charges, consumers who reduce their use of reticulated electricity will reduce their contribution to network charges. This can occur irrespective of whether or not the steps they take to reduce consumption also reduce their use of capacity provided by networks that reticulate electricity.

The overall effect of high consumption charges is then to stimulate premature investment in solar photovoltaics, relative to a counterfactual of charges that better reflect the costs of services provided. The cost of this inefficiency is estimated to be between $2.7 billion and $5.0 billion dollars (discounted present value).[2]

The range of estimated impacts covers 4 scenarios around future costs of solar photovoltaics versus grid-supplied electricity. Results for each scenario are presented in Table 1.

The costs presented in Table 1 are analogous to resources spent widening a road years in advance of any signs of rush-hour congestion. Although the investment may eventually be useful – in terms of reducing consumer's electricity bills – moving too soon is a waste. It may also be that the investment never becomes (net) beneficial.

Most of the effects of accelerated investment are likely to occur in the next 10 years but the size of the investment inefficiency shown here is estimated over a 25 year period.

[1] Based on a survey of published tariffs for Electricity Distribution Businesses (EDBs).

[2] This is the value of investment but it is also a reasonable approximation to the overall resource cost or inefficiency (see discussion in Section 5).

Table 1 Cost of accelerated investment

$ million, present value, includes effect of a tariff increase in 5 years

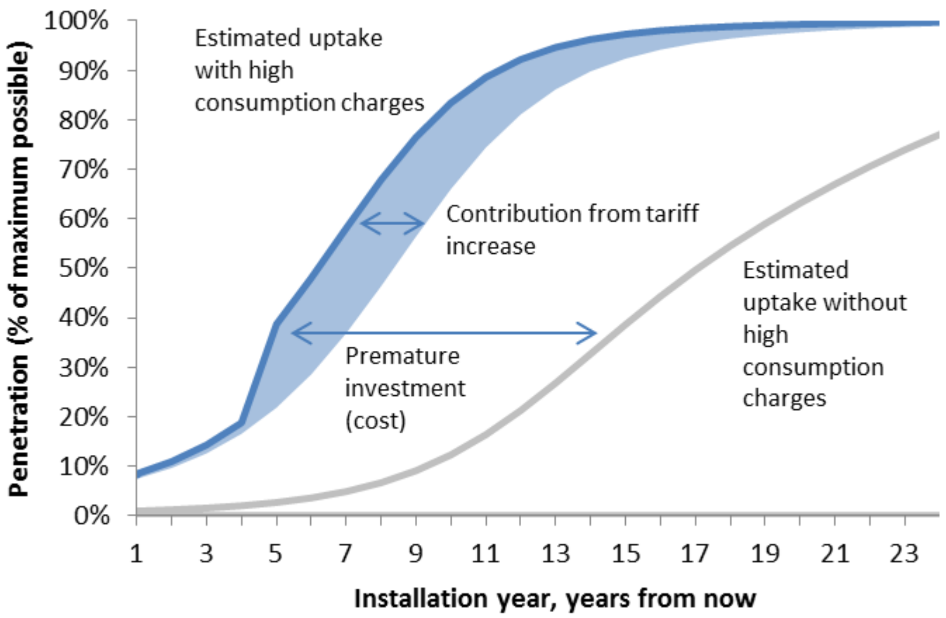
Area	Low cost photovoltaics, Low cost grid	Low cost photovoltaics, High cost grid	High cost photovoltaics, Low cost grid	High cost photovoltaic, High cost grid	Average across scenarios
UNI	1,898	659	1,511	1,076	1,286
CNI	1,259	451	978	739	857
LNI	806	779	281	1,028	724
USI	656	500	368	610	533
LSI	359	318	126	318	280
Total	4,979	2,707	3,264	3,770	3,680

Source: NZIER

Although projecting impacts over 25 years is quite speculative, this is done to ensure that only premature investment, or investment which is considered to never become economic, is counted as a cost. That is, the size of the gap in the two solar photovoltaic uptake curves in Figure 1 (with and without high consumption charge).

Figure 1 Impact of high consumption tariffs on investment in solar

Scenario with high cost solar and high cost grid-supplied electricity



Source: NZIER

The estimated investment inefficiency includes the effects of an across-the-board increase in distribution prices to ensure distributors recover the costs of their investments. As solar investment increases, the basis for revenue recovery shrinks, unless there is reduced use of consumption charges. This effect is also shown in Figure 1.

This analysis is based on an uptake of solar photovoltaics given two different sets of tariffs: a tariff with high consumption charges and one with lower consumption charges. Those tariffs are summarised in 2.1 below and described in detail Appendix A.

The analysis also considers four scenarios for future prices of grid-supplied electricity relative to electricity from solar photovoltaics. The scenarios are discussed in 2.2 and summarised in Figure 2 along with details of the model used to evaluate the relative merits of investment in solar photovoltaics.

Section 3 then investigates the impact that high consumption charges may have on pay-offs to residential investment in solar photovoltaics and stimulating premature investment.

Section 4 then considers the potential for a so-called 'cost-spiral', whereby some households avoid network costs by installing solar photovoltaics. Those costs are shifted to other consumers. This increases incentives to install solar photovoltaics. Further investment in solar shifts increased costs onto an increasingly smaller number of consumers. This increases investment in solar photovoltaics, and the effect spirals until major regulatory or other institutional and commercial changes intervene.

Section 5 provides a summary of the overall effect of high consumption charges and rising distribution prices on penetration of solar photovoltaics. This is followed (in Section 6) by a discussion on the limitations of this analysis and some sensitivity analyses.

2. Price scenarios

2.1. Tariffs with and without high consumption charges

The analysis compares two different tariff menus (Table 2):

- a menu of current actual average tariff rates with the option of
  - a high consumption charge tariff
  - a low consumption charge tariff
- a single counterfactual low consumption charge tariff.

Tariffs are analysed for each of 5 zones: Upper North Island (UNI); Central North Island (CNI); Lower North Island (LNI); Upper South Island (USI) and Lower South Island (LSI).[3]

Table 2 Retail tariffs inclusive of distribution charges

Current average retail tariff rates			Counterfactual tariffs	
Offpeak tariff, cents per kWh			*Offpeak tariff, cents per kWh*	
Zone	High consumption charge, low fixed charge (LFC) option	Low consumption charge, high fixed charge (HFC) option	Zone	
UNI	23	17	UNI	15
CNI	23	17	CNI	15
LNI	23	17	LNI	14
USI	23	17	USI	16
LSI	23	16	LSI	15
Peak tariff, cents per kWh			*Peak tariff, cents per kWh*	
Zone	High consumption charge, LFC option	Low consumption charge, HFC option	Zone	
UNI	29	22	UNI	19
CNI	29	22	CNI	19
LNI	29	21	LNI	18
USI	29	22	USI	21
LSI	28	21	LSI	20
Daily charges, cents per day			*Daily charges, cents per day*	
Zone	High consumption charge, LFC option	Low consumption charge, HFC option	Zone	
UNI	34	186	UNI	230
CNI	34	187	CNI	230
LNI	34	184	LNI	230
USI	34	187	USI	230
LSI	34	181	LSI	230

Source: NZIER, MBIE QSDEP

Current average tariffs are based on averages of prices in the Ministry of Business, Innovation and Employment's November 2014 *Quarterly Survey of Domestic Electricity Prices* (MBIE QSDEP).[4]

---

3 These zones are defined in the Network Supply Point (NSP) table produced by the Electricity Authority and published in the reports section of the Authority's data portal at http://www.emi.ea.govt.nz.

4 The MBIE survey results assume all consumers consume 8,000 kWh and are on 'low-user' tariffs. It also only provides a variable tariff value in cents per kWh. To construct multi-part tariffs and 'standard' tariffs (for people consuming over 8,000 kWh p.a.) we sampled a tariff offering by Genesis Energy Limited in the Auckland market. The ratios of 'low-user' to 'standard' charges, peak versus off-peak charges, and fixed to variable charges were used to construct

The counterfactual (more cost-reflective with comparatively low consumption charge) tariff scenarios (in Table 10) assume that all consumers face daily charges that are 46% of the average national retail bill (as discussed earlier) which equates to $2.30 per day.[5] For simplicity, the sum of all consumers' bills is assumed to be unchanged and consumption tariffs are adjusted to ensure this is the case. [6]

The counterfactual tariffs that are constructed comprise variable charges which approximate avoidable or variable costs and daily capacity charges for unavoidable or fixed costs. For the purposes of the analysis in this paper it is assumed that the variable component of the counterfactual tariff is a consumption (kWh) usage charge and that household connections have (and choose) the same capacity.[7] This assumption is applied to the regulated (distribution and transmission) components of retail tariffs. Charges of different types (for example, peak demand charges) may be used in practice but we choose a single example to ease interpretation.

2.2. Four scenarios for grid and solar supply costs

The scenarios used for grid and solar supply costs are summarised in Figure 2. Under all scenarios, the economics of solar photovoltaics are expected to improve in coming years with the cost of investing in solar photovoltaics declining by either 2.5% p.a. or 7% p.a.

The slower rate of decline (2.5%) reflects the International Energy Agency (IEA) expectation that costs of solar photovoltaics will be 40% lower in

representative tariffs by broad region using the cents per kWh prices from QSDEP to capture regional variations.

5 The counterfactual tariff structure constructed in this paper does not take into account practical and regulatory constraints which may prevent distributors and retailers from implementing it, such as the Low Fixed Charge Regulations which are said by some to constrain tariff structures.

6 This particular calculation is carried out for the average household consumption for each of the five regions. That being so it only holds on average. Analysis of household expenditure later in the report adopts more detailed analysis of household differences and thus more nuanced measures of expenditure and average prices.

7 In practice consumers might choose different levels of service, measured by capacity per time period. In this sense a capacity charge is variable and not fixed and is not the same as a fixed daily charge.

2035.[8] The faster rate of decline (7% p.a.) reflects a view from Citigroup that photovoltaics module costs will fall to US $250 per kW by 2020.[9] These equate to costs of installation of between $1,750 (low cost) and $2,500 (high cost).

Grid supply costs are assumed to increase in all scenarios but in a low grid-supply cost scenario costs increase 0.3% p.a. and in a high growth scenario these costs increase by 1.9% p.a. These scenarios are based on the two most extreme paths for the wholesale electricity price indicator in MBIE's (2015) draft *Electricity Demand and Generation Scenarios*.[10] Other assumptions used in the analysis are summarised in Table 3.

8 This expectation has been adopted by MBIE (2015) in its draft *Electricity Demand and Generation Scenarios* published on 2 April (http://www.med.govt.nz/sectors-industries/energy/energy-modelling/modelling/electricity-demand-and-generation-scenarios/draft-edgs-2015).

9 This is at the extreme end of publically available scenarios for solar photovoltaics module costs. By comparison the US Department of Energy has programmes targeting a reduction in solar photovoltaics costs amounting to $500 per kW. These are exclusive of installation costs including labour and other equipment such as inverters. Non-module costs are between 2 and 3 times module costs. In our low cost (7% decline) scenario we assume the final cost of installing solar photovoltaics is twice the module cost.

10 The high cost growth scenario (1.9%) reflects average annual growth in long run energy costs from MBIE's 'Global low carbon emissions scenario'. The low cost growth scenario (0.3) reflects average annual growth in long run energy costs from MBIE's 'High gas availability' scenarios. In these grid cost scenarios no adjustment is made for competitive response, technological or organisational changes or other possible systematic responses to price paths. The scenarios principally reflect assumptions about fuel availability and costs and relative costs of generating technology.

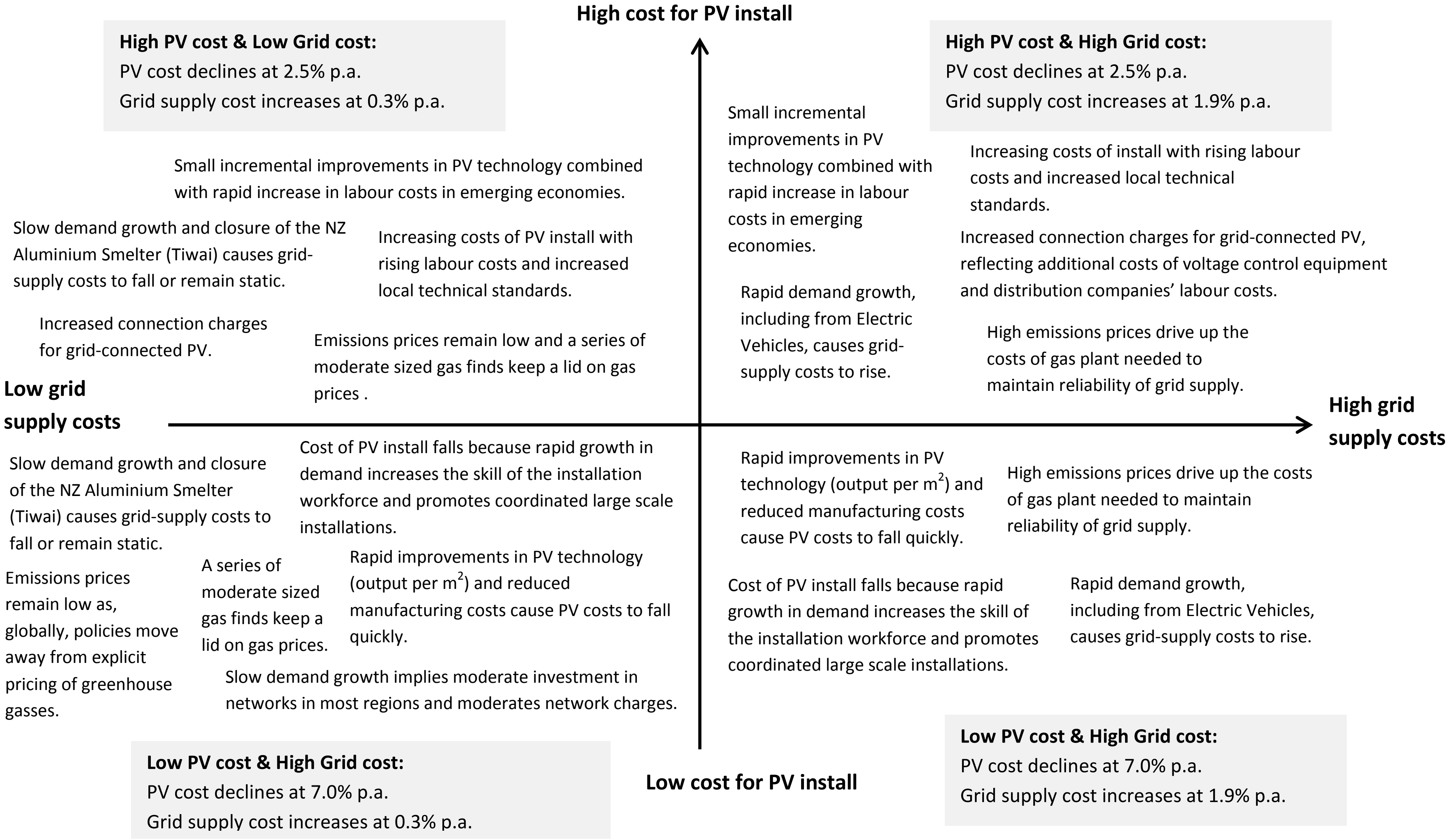
Table 3 Assumptions used in solar investment analysis

Variable	Assumption
Size of solar system (kW)	3.0
Annual deterioration in efficiency	1%
Life of solar system	25 years[11]
Buy-back rate (% of retail consumption charge/kWh)	25%
Solar photovoltaics install cost ($/kW):	
Current	3,650
Low cost scenario, 2020	1,750
High cost scenario, 2020	2,500
Solar photovoltaics operating and maintenance cost ($/kW p.a.)	$50
Solar photovoltaics generation potential (kWh p.a.):	
UNI	4,032
CNI	4,016
LNI	3,550
USI	3,261
LSI	3,000
Assumed average consumption by current tariff and area[12]	
UNI – high consumption	5,106
CNI – high consumption	5,038
LNI – high consumption	5,017
USI – high consumption	5,999
LSI – high consumption	5,946
UNI – low consumption	8,143
CNI – high consumption	6,868
LNI – low consumption	7,661
USI – low consumption	8,502
LSI – low consumption	8,131

[11] Includes life of converter, for simplicity, though the life of the inverter may be somewhat shorter than for other equipment such as solar panels.

[12] Data on consumption is from Electricity Authority summaries of retail disclosure for the year to December 2014.

Figure 2 Scenarios for relative costs of solar photovoltaics versus grid supply



Source: NZIER

3. Investment returns and uptake of solar

Currently, solar photovoltaics provides a small return on investment in most parts of New Zealand and these returns depend entirely on high consumption charges or an expectation of high grid-supply costs in future.

In the case of low future growth in grid-supply costs, high consumption charges have the effect of increasing returns to investment in solar photovoltaics by 3.4 percentage points from a small negative return to a small positive return (-0.4% to 3.0%).

The rates of return used here are internal rates of return. Internal rates of return represent the interest rate (or discount rate) an investor would need to break even given a set of known investment costs and streams of benefits over time.

Rates of return on solar investment, based on the assumptions in Table 3, are shown in Table 4. This shows the internal rate of return on installing a 3 kW solar photovoltaics module today in five regions of New Zealand. A solar photovoltaics installation is assumed to cost $10,950 per unit in all regions, but output and revenue from selling surplus generation varies by region. The gains to be made from avoiding payments for grid-supplied electricity also vary according to regional tariffs and whether consumers are on high consumption or low consumption tariffs.[13]

The rates of return in Table 4 can be readily compared to rates of return for other investments. Under current price structures and with high growth in grid-supply costs, a solar photovoltaics installation in the Upper North Island will provide a positive rate of return but a rate of return that is lower than the historical average of very low risk interest rates such as long term average term deposit rates of 6% (6 month term, RBNZ). This means consumers, on average, will be better off saving the cost of solar photovoltaics installation and continuing to use grid-supplied energy for all their electricity supply.[14]

[13] These results reflect average tariffs (for each of high variable and low variable tariffs), average electricity consumption, average time of use of electricity and average hourly sun radiance by region.

[14] The reason deposit rates are used here is because deposit rates are simple and are reasonably widely understood. Note also, that this rough comparison does not take account of income tax, with returns on term deposits subject to income tax.

Table 4 Annual rates of return on installing solar photovoltaics

By grid cost scenario and with factual high and low consumption and counterfactual tariff scenarios and rise in distribution tariffs.

Type of tariff and typical consumption	Area	Low cost grid supply	High cost grid supply
Existing (factual) tariff – low user	UNI	2.9%	4.9%
	CNI	2.8%	4.8%
	LNI	1.7%	3.6%
	USI	2.0%	3.9%
	LSI	1.4%	3.3%
Existing (factual) tariff – above average user	UNI	4.8%	6.6%
	CNI	5.1%	6.9%
	LNI	3.6%	5.4%
	USI	2.7%	4.6%
	LSI	2.0%	3.9%
Counterfactual tariff – low user	UNI	-0.1%	1.8%
	CNI	-0.2%	1.7%
	LNI	-1.2%	0.7%
	USI	-0.6%	1.3%
	LSI	-1.5%	0.5%
Counterfactual tariff – above average user	UNI	1.1%	3.0%
	CNI	0.8%	2.7%
	LNI	-0.1%	1.8%
	USI	0.5%	2.4%
	LSI	-0.5%	1.4%
Change due to high consumption tariffs - low user	UNI	3.0%	3.1%
	CNI	3.0%	3.1%
	LNI	2.9%	2.8%
	USI	2.6%	2.6%
	LSI	2.8%	2.8%
Change due to high consumption tariffs – above average user	UNI	3.7%	3.6%
	CNI	4.3%	4.3%
	LNI	3.7%	3.6%
	USI	2.2%	2.2%
	LSI	2.5%	2.4%

Source: NZIER

This comparison of rates of return on solar investments and rates of return from term deposits ignores the riskiness of an investment in solar.[15] Alternative risk- adjusted benchmarks for returns are likely to be much higher. Risk-adjusted rates summarise the so-called 'opportunity cost of capital', or what might reasonably be achieved, on average, from an investment. The Treasury, for example, uses benchmark rates for the opportunity cost of capital of around 8%. On this benchmark, returns on solar photovoltaics investments are very low.

Rates of return to solar photovoltaics are expected to improve over time as installation costs decline. An example of this is shown in the left panel of Figure 3. This shows that the high consumption tariffs increase returns to solar photovoltaics over time and so there is expected to be an increasing rate of solar photovoltaic uptake over time.

To assess the implications of this increase, we assume that the decision to invest in solar photovoltaics is a function of rates of return. The relationship between rates of return and investment is shown in the right panel of Figure 3. The shape of this relationship is calibrated to actual penetration rates to date (e.g. average 2.9% rates of return to solar photovoltaics in the Upper North Island and 0.3% penetration as at end 2014).

Using a continuous relationship between returns and investment allows for the idea that some people decide to install solar photovoltaics for reasons other than financial rates of return – reasons we have not captured or cannot see including non-financial factors.

The right panel of Figure 3 shows uptake reaching 100%. This should be interpreted as 100% of technically feasible installations. Sensitivity analysis has been used to consider the implications of different numbers of technically feasible installations.

Relationships between internal rates of return (irr) and rates of solar photovoltaics installation, $p(PV|IRR)$, are based on the following equation:

[15] This riskiness includes, for example, the risk that costs of grid-supplied electricity are lower than expected, the risk that distributors introduce charges that cannot be avoided by solar panels (for example a peak demand charge or time-varying consumption charges that are higher in the evening)and the risk that the installation's useful life is shorter than expected.

$$p(PV|IRR) = \frac{e^{\alpha.\beta.irr}}{1 + e^{\alpha.\beta.irr}}$$

The values for α and β are calibrated so that this function is approximately matched to observed rates of uptake of solar photovoltaics. The results of this calibration are summarised in the table of 'Uptake parameters' below.

For simplicity the estimates of the uptake of solar photovoltaics ignore any growth in the number of ICPs.

Rates of uptake vary widely based on expectations of future grid costs, future costs of solar photovoltaics and hence rates of return. Average uptake of solar photovoltaics in the next 10 years with the high consumption charge tariff is estimated to range from 7% of ICPs nationwide – in the high photovoltaics cost and low grid cost scenario – to 73% of ICPs nationwide with rapid photovoltaics cost-declines and high costs of grid supply.

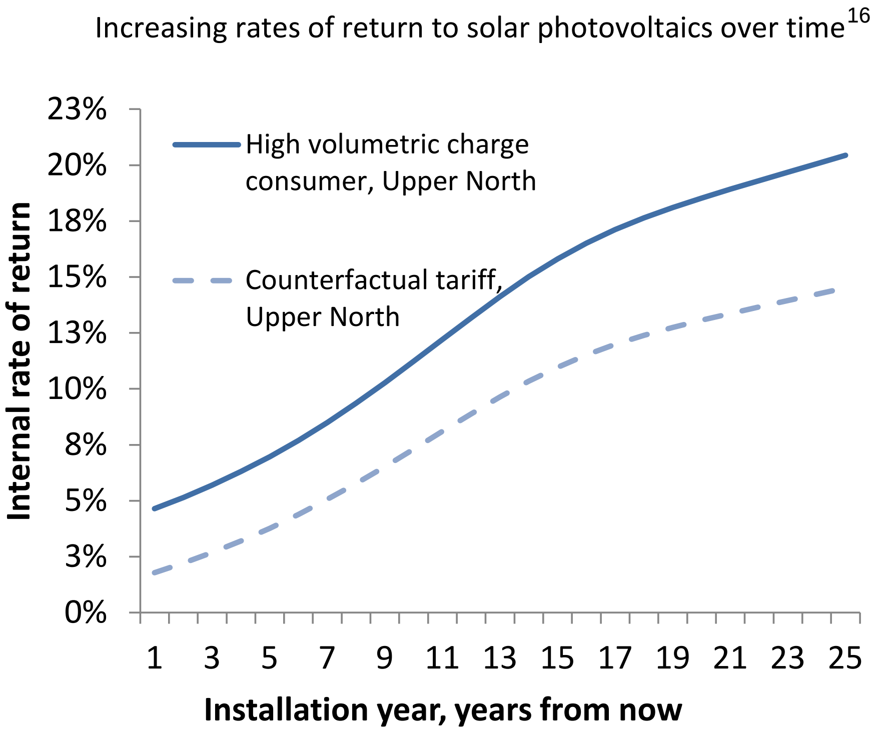
In these scenarios high consumption tariffs are a major cause of the increased uptake of solar photovoltaics. This can be seen in Table 7 below (page 18) where half of uptake in the highest uptake scenario is due to benefits from reduced retail bills associated with high consumption charges – as opposed to relative economics of supply from solar photovoltaics versus grid supply.

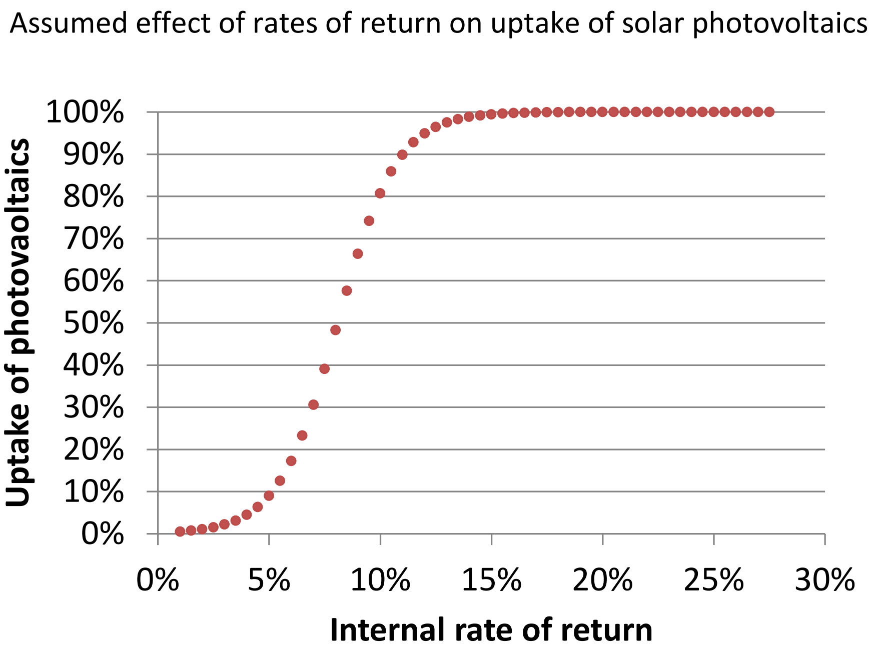
Table 5 Solar photovoltaic uptake parameters

	UNI	CNI	LNI	USI	LSI
Current capacity (MW)	5.33	2.96	1.51	3.86	1.78
p(solar photovoltaics=1)*100	0.26	0.22	0.12	0.36	0.28
Current p(solar photovoltaics=1)	0.003	0.002	0.001	0.004	0.003
Average estimate IRR	0.03	0.03	0.02	0.01	0.01
alpha	-6	-6.15	-6.7	-5.7	-5.8
beta	75	75	75	75	75
Fitted value	0.003	0.002	0.001	0.003	0.003
Error	0.000	0.000	0.000	0.000	0.000
% error	1%	1%	3%	8%	6%

Source: NZIER

Figure 3 Relationship between rates of return and investment





Source: NZIER

[16] Example from Low photovoltaics cost – High Grid cost scenario.

4. Price increases resulting from increased investment in solar

At the same time as investment in solar photovoltaics is accelerated, grid-based consumption declines and, with widespread use of consumption tariffs, this reduces the base over which revenue needs to be recovered to cover system costs (distribution and transmission).[17]

[17] This dynamic is most acute, or at least most apparent, when consumption is flat or declining. It is also a problem if consumption is growing, to the extent that consumers end up paying more for the services they receive than they otherwise would.

Table 6 sets out average percentage changes in consumption tariffs in 5 and 10 years from now needed to ensure system costs are recovered under each of the above scenarios.[18]

The rise in consumption tariffs shown here is predicated on five-yearly price reviews – corresponding to current regulatory practice.

The tariff increases shown here assume imperfect knowledge on the part of regulators. Tariffs are recalibrated to recover system costs as at the year of price reviews. There is no allowance made for future declines in consumption and no allowance made for revenue under-recovery in previous periods. This means that distributors, in the scenarios shown here, will not recover their allowable revenue. This may have negative effects on service quality but these effects have not been analysed for this report.

Here the focus of impacts is on price changes in the next 10 years, including the effects of a single price rise. Analysing effects given a single price increase avoids making judgements about the sustainability of spiralling costs and focusses mainly on the sensitivity of the investment inefficiency to spiralling costs. It provides an illustration of the speed with which the investment inefficiencies can 'get away on you'.

[18] This analysis assumes that recovery of this revenue gap will be achieved through raised volumetric (kWh) charges. This assumption reflects current practice.

Table 6 Consumption charge changes used to ensure system costs are recovered

Area	Low cost PV , Low cost Grid	Low cost PV , High cost Grid	High cost PV , Low cost Grid	High cost PV , High cost Grid	Average across scenarios
Year 5, low users					
UNI	2.2%	11.1%	1.4%	7.6%	5.6%
CNI	1.7%	9.3%	1.1%	6.3%	4.6%
LNI	0.4%	2.6%	0.3%	1.7%	1.2%
USI	1.1%	6.3%	0.7%	4.3%	3.1%
LSI	0.7%	3.9%	0.4%	2.6%	1.9%
Year 5, above average users					
UNI	4.1%	11.4%	2.7%	9.3%	6.9%
CNI	4.4%	12.0%	2.9%	9.8%	7.3%
LNI	0.9%	4.4%	0.5%	3.0%	2.2%
USI	1.0%	4.8%	0.7%	3.4%	2.5%
LSI	0.5%	2.9%	0.3%	1.9%	1.4%
Year 10, low users					
UNI	12.6%	30.6%	3.8%	22.0%	17.3%
CNI	10.7%	29.8%	3.0%	20.0%	15.8%
LNI	2.8%	19.1%	0.7%	7.8%	7.6%
USI	6.9%	21.9%	2.0%	14.0%	11.2%
LSI	4.1%	19.5%	1.1%	10.2%	8.8%
Year 10, above average users					
UNI	12.5%	15.1%	6.5%	14.1%	12.0%
CNI	13.2%	15.7%	6.9%	14.8%	12.7%
LNI	5.5%	12.5%	1.6%	9.1%	7.2%
USI	5.5%	11.3%	1.8%	8.8%	6.9%
LSI	3.2%	10.0%	0.9%	6.5%	5.2%

Source: NZIER

5. Overall implications for investment in solar

Based on these different effects and investment paths, and assuming that solar photovoltaics installations have a useful life of 25 years, penetration of solar is estimated to be many times larger with high consumption charges than without the high consumption charges. The estimated effects are shown in Table 7. As discussed earlier, the cost of this inefficiency is estimated to be between $2.7 billion and $5.0 billion dollars (discounted present value).

A summary of the value of accelerated investment (average results across four scenarios) is presented in Table 7 below.

This is the value of investment but it is also a reasonable approximation to the overall resource cost or inefficiency. Use of solar photovoltaics will mean reduced resource costs from reduced operation of grid connected electricity generation and this can be considered a (gross) benefit. However it will also create other resource costs including operating and maintenance costs for solar photovoltaics, reduced fiscal revenue (GST)[19], and losses to consumers who reduce their consumption when faced with higher network charges. By our estimation these costs and benefits broadly offset each other, leaving the investment cost as a reasonable approximation to the overall efficiency cost.[20]

Table 7 Value of accelerated investment

Average across the four scenarios

Results after:	Total investment in PV ($ millions) –high variable charges	Total investment in PV ($ millions) – in counterfactual	Investment in PV brought forward ($ millions) – in counterfactual	Cumulative investment in PV brought forward ($ millions)
5 years	2,603	249	2,354	2,354
10 years	3,081	1,165	1,916	4,271
15 years	1,148	1,334	-186	4,085
20 years	190	435	-245	3,840
25 years	38	157	-119	3,721

Source: NZIER

[19] This revenue needs to be recovered through higher tax rates elsewhere. The efficiency cost of taxes rises with at least the square of the tax rate, meaning that reducing GST revenue is, here, a real resource cost.

[20] This is based on assumptions that short run average generating costs are 5.5 c/kWh (see MBIE (2015) Draft Electricity Demand and Generation Scenarios) and annual operating and maintenance costs of solar photovoltaics average $50 per kW per year equating to a cost of between 3 and 5 cents per kWh depending on the region of installation. Reductions in GST range from 1.8 to 2.2 c/kWh depending on region – although they vary according to assumptions about the rate of growth in retail electricity prices.

Table 8 Solar photovoltaics uptake in 10 years' time by cost scenario

With and without the high consumption charge tariff

		Low cost photovoltaics, Low cost Grid	Low cost photovoltaics, High cost Grid	High cost photovoltaics, Low cost Grid	High cost photovoltaics, High cost grid
Existing (factual) tariff – low user	UNI	45%	98%	13%	83%
	CNI	37%	97%	10%	77%
	LNI	10%	71%	2%	30%
	USI	30%	94%	8%	67%
	LSI	17%	85%	5%	48%
Existing (factual) tariff – above average user	UNI	84%	99%	45%	95%
	CNI	85%	99%	46%	95%
	LNI	41%	94%	12%	69%
	USI	46%	94%	15%	74%
	LSI	28%	88%	8%	57%
Counterfactual tariff – low user	UNI	4%	37%	1%	12%
	CNI	3%	31%	1%	10%
	LNI	1%	10%	0%	3%
	USI	3%	35%	1%	12%
	LSI	1%	19%	0%	6%
Counterfactual tariff – above average user	UNI	11%	68%	3%	31%
	CNI	7%	56%	2%	21%
	LNI	2%	25%	1%	7%
	USI	9%	62%	3%	27%
	LSI	4%	37%	1%	13%
Change due to high consumption tariffs - low user	UNI	41%	61%	12%	71%
	CNI	34%	66%	9%	67%
	LNI	9%	61%	2%	27%
	USI	27%	59%	7%	56%
	LSI	16%	66%	4%	42%
Change due to high consumption tariffs – above average user	UNI	73%	31%	42%	64%
	CNI	78%	44%	44%	74%
	LNI	39%	69%	11%	62%
	USI	37%	32%	12%	47%
	LSI	25%	51%	7%	44%

Source: NZIER

6. Some caveats and sensitivity analyses

There are a number of key points of sensitivity in these results. One is that the uptake figures shown in Table 7 are highly ambitious given the current capacity in the solar installation industry.

It turns out that these results do not depend critically on the ability of suppliers to meet accelerated demand for solar photovoltaics. The fact that impacts are measured as changes relative to a baseline means that the largest impacts do not require the most favourable conditions for solar or the most rapid uptake.

That is, the scenario with the largest uptake, the low cost solar and high cost grid scenario, is not the most costly though it does assume the most extreme supply capacity with 450 MW of solar photovoltaics to be installed on average for each year of the next decade. This is very high, given that the peak rate of install in Australia was around 300 MW per annum.

The scenario with the highest costs has an implied install rate of 220 MW per annum. This too seems high, however slower supply-constrained adoption would not change the implications of this analysis unless it could be shown that solar costs did not rise to choke off demand.

If we assume that supply constraints do cause a slowdown in the adoption of solar this would be reflected in higher install costs. This then shifts the focus to the scenarios with comparatively high photovoltaic costs. This includes the scenario with high cost photovoltaics and low cost grid scenario which demands only 90 MW of solar be installed on average over decade.

The value of the investment impacts shown here are dependent on the number of households for which solar photovoltaics are a technically feasible option. The default assumption used above is that 100% of households can adopt solar photovoltaics.

The sensitivity of this analysis to assumptions about maximum feasible uptake of solar photovoltaics is shown in Table 9. As before, impacts are approximately proportional to the proportion of households for which solar photovoltaics are technically feasible. Alternative assumptions about maximum feasible uptake will, more or less, proportionately reduce impacts.

In addition to inefficient solar investment, price increases would also cause reductions in electricity consumption because of reduced household purchasing power. This, in turn, would cause further price increases and further reductions in consumption.

Rising prices are not guaranteed of course. Regulators could, for example, spread the impacts of accelerated solar photovoltaics investments on regulated revenue across distribution network owners and consumers. This would be done by allowing both price increases and reducing distributors' allowable revenues. Whether or not this sort of action makes sense remains to be seen and depends on issues such as:

- why solar photovoltaics investments are accelerating
- whether demand for distribution services is declining
- whether the ongoing quality of distribution services would be put unnecessarily at risk from falling revenue.

The analysis above points to answers to the first two of these questions but a definitive assessment of these wider regulatory issues is far beyond the scope of this report.

Table 9 Value of accelerated investment in solar photovoltaics with varying maximum percentage penetration

$ million, present value, with one tariff increase at year 5

	Low-Low	Low-High	High-Low	High-High
Investment impacts				
100%	4,713	3,199	2,874	4,022
90%	4,222	2,839	2,571	3,577
80%	3,735	2,486	2,272	3,140
70%	3,253	2,141	1,976	2,712
60%	2,775	1,804	1,683	2,294
50%	2,301	1,477	1,394	1,886
Impact relative to 100% maximum penetration				
100%	100%	100%	100%	100%
90%	90%	89%	89%	89%
80%	79%	78%	79%	78%
70%	69%	67%	69%	67%
60%	59%	56%	59%	57%
50%	49%	46%	49%	47%

Source: NZIER

Appendix A Current and counterfactual tariffs

Current average tariffs are based on averages of prices in the Ministry of Business, Innovation and Employment's November 2014 *Quarterly Survey of Domestic Electricity Prices* (MBIE QSDEP).[21] Residential consumers are assumed to self-select between the two different tariffs based on whichever tariff results in the lowest bill.

Construction of the counterfactual tariff is summarised in Table 10 and Table 11. The first column in Table 10 is the amount of revenue that each distributor is allowed to recover for the next five years. This revenue is made up of an estimate of future costs of serving future demand (second column in Table 10) plus a sum that ensures firms can recover their overheads and investors can recover the costs of their past investments (third column in Table 10).[22]

Costs of past investment are assumed to be recovered through daily connection capacity charges (measured per ICP), as shown in the far right column. As discussed at the outset, connection capacity is assumed to be the same for households.

Costs deemed to vary in future according to consumers' decisions are recovered by the counterfactual variable consumption charge. In practice, consumption of electricity is a weak indicator of variable cost of electricity

---

[21] The MBIE survey results assume all consumers consume 8,000 kWh and are on 'low-user' tariffs. It also only provides a variable tariff value in cents per kWh. To construct multi-part tariffs and 'standard' tariffs (for people consuming over 8,000 kWh p.a.) we sampled a tariff offering by Genesis Energy Limited in the Auckland market. The ratios of 'low-user' to 'standard' charges, peak versus off-peak charges, and fixed to variable charges were used to construct representative tariffs by broad region using the cents per kWh prices from QSDEP to capture regional variations.

[22] The calculation for future costs of future demand is: present value of forecast capex plus forecast increases in operating expenditure, divided by changes in demand. We use ICPs and forecast constant price revenue growth to measure demand. Thus the resulting cost per ICP cost. This is similar to a Long Run Marginal Cost calculation but includes all future costs rather than growth-related costs, for simplicity and because data on future costs is more readily available than data on growth-related costs. The calculations reflect the building blocks methodology currently used by the Commerce Commission for setting allowable revenue. This is a different purpose compared to setting prices themselves on the basis of marginal cost and other approaches to calculate marginal costs may be more appropriate for the purpose of price setting.

supply though it is commonly used in tariffs partly because, in practice, it is relatively easy to measure.

A daily connection capacity charge does also vary with demand, such as by days connected, by size of capacity, and by distribution network area. It is only for the sake of keeping things simple that this sort of variation is ignored. In any case most residential consumers have sufficiently similar connections that they would not face different daily charges (for a given network area).

A further point of practical caveat, is that the counterfactual tariff structure constructed here does not take into account other practical and regulatory constraints which may prevent distributors and retailers from implementing it, such as the Low Fixed Charge Regulations. Given these practical considerations, the tariffs shown here are a tool of analysis and not a recommendation.

Average costs of past investment are estimated to be between 74 cents and $1.97 per customer per day depending on the network.[23] Note that this figure excludes transmission charges. Transmission interconnection charges would, for example, add approximately 50 cents per day if they were allocated on a per-ICP basis. This raises minimum daily connection charges to more than $1 per day (i.e. $1.24 – $2.47 per day).[24]

Based on this approach, the upper bound share of distribution revenue that might be raised from consumption charges is 45%, on average. The lower bound on consumption charges is 0%, where all allowable revenue is recovered via the daily connection capacity charge.

Actual average share of revenue recovered from consumption charges in practice is 78%.

A key general point from this analysis, caveats aside, is that if price structures were tilted towards being more cost-reflective, consumption (kWh) charges would be substantially lower than they are currently. This fact has significant implications for investment in solar photovoltaics, as discussed in the next section.

Allowing for the possibility of no consumption charges in distribution tariffs is reasonable on the grounds that a large amount of distribution

[23] Networks in Tasman, Nelson and Canterbury (Orion) are excluded due to difficulties reconciling data.

[24] This figure does not include all transmission charges, since connection charges are excluded. If these were included, estimated daily charges would be higher again.

asset investment does not vary with use. This includes, for example, investment in conductors (cables), poles and related replacement expenditure. This sort of spending does not typically vary with consumption – at least in the case of residential demand.

An extreme case then for retail pricing of distribution services – the upper bound – would be one where all investment was in assets such as poles and cables. In this case all lines and transmission charges would be daily charges and the only variable consumption charge in domestic consumers' retail bills would be for the generation of electricity.

Table 10 Cost context for counterfactual distribution tariffs

Dollars. Present Value, 2015. Estimated orders of magnitude based on Commerce Commission modelling.[25]

	Allowable revenue[26]	Future costs of serving future demand	Overheads and cost of past investment	Implied lower bound on connection capacity charge per ICP per day[27]	Implied upper bound on average charge per ICP per day
Alpine	163,099,020	54,727,425	108,371,595	1.57	2.37
Aurora	247,691,737	92,954,881	154,736,856	0.85	1.36
Centralines	48,814,569	14,917,496	33,897,073	1.97	2.83
Eastland	103,952,687	54,074,012	49,878,675	0.91	1.89
Electricity Ashburton	144,179,693	87,804,101	56,375,592	1.41	3.61
Electricity Invercargill	58,957,105	26,630,283	32,326,822	0.85	1.54
Horizon Energy	95,547,211	40,109,026	55,438,185	1.03	1.77
OtagoNet	108,078,052	50,542,312	57,535,740	1.73	3.25
Powerco	1,087,074,297	519,284,847	567,789,451	0.81	1.56
The Lines Company	148,967,866	55,531,814	93,436,053	1.82	2.90
Top Energy	168,714,387	97,349,840	71,364,547	1.08	2.54
Unison	436,524,631	208,232,743	228,291,888	0.94	1.79
Vector	1,749,930,119	779,978,116	969,952,004	0.77	1.39
Wellington Electricity	432,008,258	155,535,551	276,472,707	0.74	1.16

Source: NZIER

25 'Financial-model-EDB-DPP-2015-2020.xlsx' available at http://www.comcom.govt.nz/regulated-industries/electricity/electricity-default-price-quality-path/default-price-quality-path-from-2015/.

26 This is the full amount applying to all regulated services and covers residential, commercial, and industrial consumers.

27 The per-ICP values are based on an assumption that all ICPs are charged a pro-rata share of the overheads and past investment components of revenue. An implication of this assumption is that daily connection capacity charges are the same for a household as for a business or for a factory. This does not hold in practice but there is no generic way, in the context of this analysis, to allocate higher or lower charges per ICP to one category of customer or another. Furthermore, analysis of the efficient allocation of revenue as between residential, commercial and industrial consumers is beyond the scope of this paper.

Extending this analysis to retail charges, the proportion of a consumer's bill based on consumption charges, as an upper bound, is around 54% of the current average[28] consumer's bill. The results of our analysis are outlined in Table 11. The first column shows how large daily charges would be if all fixed costs of supply were recovered with daily charges. This includes estimates of:

- fixed costs of distribution
- fixed costs of transmission
- retailer overheads
- metering costs.

Estimates of the variable component of costs are based on typical wholesale energy costs by network area and the variable (cost-reflective price signal) components of transmission and distribution prices.

The results in Table 11 also show significant variation amongst distribution areas in terms of the portion of costs apportioned to consumption charges. Two sets of estimates are provided: an upper bound for consumption charges based on the lower bound estimates for fixed distribution charges in Table 10; and a lower bound for consumption charges based on only marginal costs of energy supplied being priced on a consumption basis.[29] The gap between these two estimates, in terms of shares of bills that are based on consumption charges, is smallest for more sparsely populated areas where distribution typically makes up a larger share of residential electricity bills.

This analysis is also based on estimates of:

- retail costs of supply from NZIER's cost index, which do not vary by household consumption, including:[30]
  - retail overheads (70 cents per ICP per day)

[28] Annual consumption of approximately 7,000 kWh. Analysis assumes constant consumer demand in future.

[29] In practical terms this is not a true lower bound for volumetric charges because retailers are free to offer daily charge tariffs for energy consumed, if they choose. However, 'all-you-can-eat' tariffs would be a radical departure from current retail practice and, if widely applied, would not be very efficient (see Borenstein, S. and S. Holland (2005) 'On the efficiency of Competitive Electricity Markets with Time-Invariant Retail Prices', *The Rand Journal of Economics,* vol. 36, no.3, pp.469-493).

[30] ftp://ftp.emi.ea.govt.nz/Datasets/Supplementary_information/2014/20140720_NZIER_synthetic_retail_price/NZIER_synthetic__retail_price.pdf.

  - metering charges (17 cents per ICP per day)
- fixed transmission costs based on information on residential transmission charges from the Commerce Commission collated information disclosures and Transpower New Zealand Limited’s (Transpower) data on charges by distributor, assuming that fixed transmission costs are the same proportion of transmission charges as they are for distribution costs[31]
- estimates of variable costs based on:
  - marginal costs of energy supplied (average around 8 c/kWh based on forward market energy prices, using data in NZIER’s cost index)
  - network charges not covered by daily charges, apportioning these by kWh as a first approximation.

[31] This is a simplifying assumption. One reason this assumption is used is to avoid addressing questions of where Transpower’s fixed costs lie and from whom they should be recovered. Such issues are currently under scrutiny in the Authority’s review of the Transmission Pricing Methodology and forming a firm view on them is beyond the scope of this analysis.

Table 11 Counterfactual consumption charges in retail tariffs

$ in 2015. Retail prices. Excludes GST, EA Levy. Cost shares based on 7,000 kWh consumption p.a.

	Lower bound share of consumption charges			Upper bound share of consumption charges		
	Notional fixed costs, $ per ICP per day	Notional variable cost cents per kWh	Share of bill charged on consumption basis	Notional fixed costs, $ per ICP per day	Notional variable cost cents per kWh	Share of bill charged on consumption basis
Alpine	2.8	8.5	36%	2.6	9.7	59%
Aurora	2.2	8.2	41%	2.0	9.5	52%
Centralines	3.9	8.1	28%	3.4	11.2	61%
Eastland	2.4	7.9	39%	2.0	10.2	50%
Electricity Ashburton	2.6	8.7	39%	2.4	9.8	56%
Electricity Invercargill	1.8	8	46%	1.7	8.6	51%
Horizon Energy	2.2	8.1	42%	2.0	9	54%
OtagoNet	2.9	9.2	38%	2.7	10.3	58%
Powerco	2.4	8.3	40%	2.0	10.3	50%
The Lines Company	3.3	8.3	33%	2.9	10.4	59%
Top Energy	2.6	7.7	36%	2.1	10.4	51%
Unison	2.3	8.2	41%	2.0	9.5	53%
Vector	2.2	8.4	42%	1.9	10	50%
Wellington Electricity	2.3	8.6	41%	2.0	10.3	50%

Source: NZIER