Solar PV in a hydro based grid -A New Zealand case study.

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Abstract

In this paper we examine the potential contribution that solar can make to New Zealand's electricity mix. We start off by looking at indicative statistics to see how solar generation interacts with demand and lake inflows. We see that monthly solar PV generation is negatively correlated with demand which for New Zealand peaks in winter. Hourly PV generation is correlated with demand for the lowest 80% of demand periods, however thereafter solar availability decreases sharply. Accumulated inflows are negatively correlated with accumulated solar generation during the crucial months leading up to winter. We run simulations to see how large amounts of solar PV would influence the electricity market in the long run and find that the strong negative seasonal correlation between solar generation and demand sees long run system costs increase as the amount of solar increases and displaces other types of generation.

Keywords: electricity markets; Solar PV; New Zealand; intermittent generation

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1. Introduction

Industrialized countries are investing in renewable resources for the production of energy, primarily electricity to decrease CO_2 emissions. Building a low carbon electricity grid is challenging - renewable electricity sources are often volatile and unpredictable so relying solely on one kind of intermittent renewable generation can impose strains on the electricity network. One promising solution is to design a portfolio of substitutable renewables in order to reduce the need for costly conventional backup generation, and enable a higher renewable contribution and prevent spikes in the electricity price (Pritchard, Zakeri, and Philpott, 2010; Khazaei and Zakeri, 2012; and Hirth, 2013).

In the context of solar, there are concerns that large solar penetration leads to the risk of over generation (when demand is low and it is sunny). Furthermore, as the sun sets other generators have to ramp up very quickly to serve the evening peak in demand. This effect can be illustrated through a so-called duck chart (California ISO, 2013). In spite of these concerns, solar capacity has continued to increase worldwide owing to government subsidies as well as economies of scale and technology improvements which reduce costs.

Many previous studies have explored different aspects of hybrid models - particularly with solar and wind generation. The aim is to try and understand how the variability inherent in solar and wind generation can complement each other. This has important implications for optimising the utilization of renewable resources to minimise the generation cost and improve the security of supply (Ashok, 2007; Nikolakakis and Fthenakis, 2011; Yang, Wei, and Chengzhi, 2009). Heide et al. (2010, 2011) investigate a high-renewable scenario for the European grid with large amounts of solar and wind. Their conclusion is that such a system requires large amounts of balancing generation and/or storage. They do find that seasonal variability is important with solar generation more important in summer and wind in winter. A number of other studies also examine the 'optimal' combination of wind and solar power. For example, Lund (2009) finds that it is optimal to have a mixture of solar and wind for Denmark. In general, the literature supports incorporating both renewable sources to reduce the net variability in power supply - reducing the need for reserves and costly peakers (Lund, 2009; Bett and Thornton, 2015; Hoicka, and Rowlands, 2011).

There is considerably less statistical analysis of hybrid renewable systems with substantial hydro combined with wind or solar generation. A question comes up as to whether these intermittent resources are substitutes or complements. This issue is important for the hydro-based electricity generation jurisdictions such as New Zealand, Colombia, Brazil and Chile. Ehnberg and Bollen (2005) have found that the mix of solar and hydro works well, particularly when there is a limitation in the hydro storage capacity. One attractive feature of hydro generation is that output can ramp up and down quickly, making it an ideal complement to intermittent generation. Jaramillo et. al (2004) propose a hybrid wind and hydro system for different regions in Mexico which can deliver firm power to the grid. Over a longer time-frame including intermittent generation renewable energy in a hydro grid can improve energy security. Denault et. al. (2009) analyse the hydro based system in Quebec and conclude that including up to 30% wind improves the deficit risk profile compared to an all-hydro system.

In New Zealand, there is not sufficient hydropower, particularly during dry years, because there is only limited storage capacity in the hydro lakes. One option to improve the security of renewable supply may be to have a portfolio of solar, wind and geothermal generation as well as hydro. In New Zealand, the government has a target to decrease greenhouse gas emissions from electricity generation by increasing the amount of renewable generation from 75% to 90% by 2025 (Ministry of Economic Development, 2011). Masson et al. (2010) examine a scenario with 100% use of clean resources including wind, hydro, geothermal and biomass to generate electricity in New Zealand which envisages a substantial increase in wind power. However, the study neglects solar generation although it is likely to have a significant contribution in near future. Browne et al. (2014) examine the impact of increased wind generation on price volatility and market power, however they do not analyse the effect of increased intermittent wind generation on hydro lake storage and security of supply. Other papers focus on a correlation analysis between wind and hydropower (Bull, 2010). Suomalainen et al. (2015) analyse the correlation between the seasonal pattern of wind power with hydro lake levels, demand and the price of electricity in New Zealand. The aim of their study is to clarify the impact of the expanded wind power stations on the electricity sector as well as its relation with hydropower. However, there has not been any similar studies examining solar power in the hydro-based NZ grid.

In New Zealand solar PV does not receive any direct government subsidies. Despite this, the decrease in the price of solar PV means that it is increasingly common for consumers to install rooftop units and substitute own production for retail purchases of electricity. As solar PV costs come down there has been a dramatic increase in capacity - albeit from a low base. Figure 1 (Electricity Authority, 2016a) shows the increase in installed solar capacity in the last few years. As costs are expected to decrease further over the next decade the rate of increase is likely to intensify. Miller et. al. (2016) estimate that eventually installed solar capacity in New Zealand could be up to 5.5GW. To put this in context the current peak demand in New Zealand is about 6.5GW.

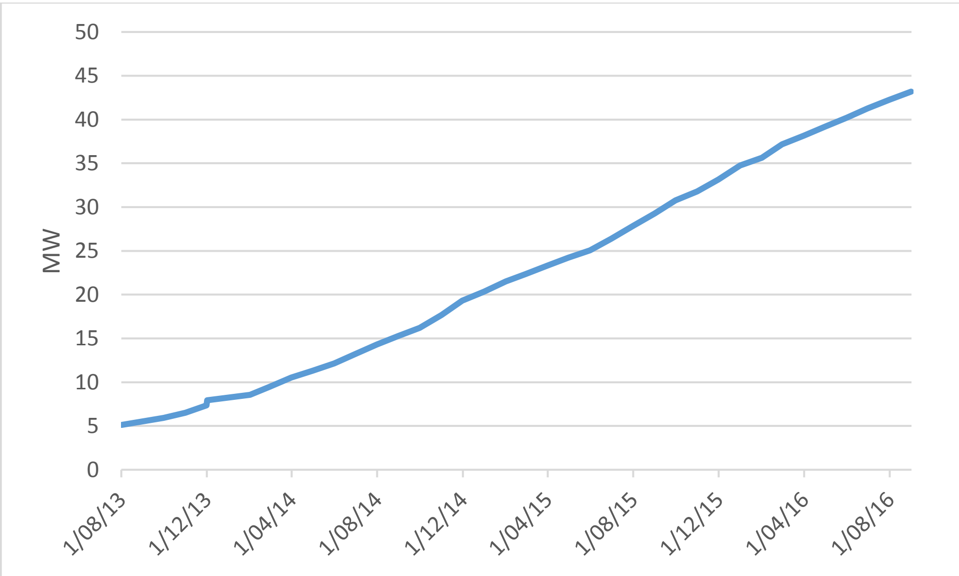


Figure 1: Installed Solar PV in New Zealand

In this paper we examine the potential contribution that solar can make to New Zealand's electricity mix. We start off by looking at indicative statistics to see how solar generation interacts with demand and lake inflows. Then in section 3 we examine the geographical potential of solar PV by analysing the seasonal correlations and anomalies of solar production, demand, lake inflows and prices. In section 4 we look at how large amounts of rooftop PV would influence the electricity market in the long run. We run market simulations for scenarios with different amounts of solar to understand how the statistical relationships identified in section 2 and 3 leads to different market outcomes with solar in the mix. Finally, we finish with some concluding remarks.

2. Indicative Statistics of National Solar Output

The solar data that we use in this study is from National Institute of Water and Atmospheric Research (NIWA, 2014). It is hourly measurements in MJ/m^2 from 2002 to 2013. In Appendix A we describe how the raw data is used to generate solar power for the ten biggest cities in New Zealand using the Olmo et. al. (1990) model. In this section we look at national output, which is defined using weights based on installed capacity for the 10 biggest cities as of 2016 (Electricity Authority, 2016a). The solar panels are assumed to be north facing with an inclination angle chosen (for each location) to maximise total solar generation over the year. Not all sites reported valid solar data at all times. In this case we used the solar data from a neighbouring site.

Figure 1 illustrates the national average daily capacity factor for solar energy. We use the standard definition of the capacity factor which is defined as the solar power generated by a 1kW panel divided by 1kW. A 1kW PV panel is defined by the requirement that when the solar power is 1kW/m^2 the output of the PV panel is 1kW. Very occasionally solar power can be higher than 1kW/m^2 which means at times the capacity factor will be higher than one. The figure illustrates a clear seasonal pattern with a large variation. Output reaches its maximum in summer and minimum in winter with maximum average monthly capacity factor of 23% - which is more than double the minimum of 11% in June. Also plotted on the chart is average daily demand for 2010 illustrating the winter peak which coincides with low solar capacity factors.

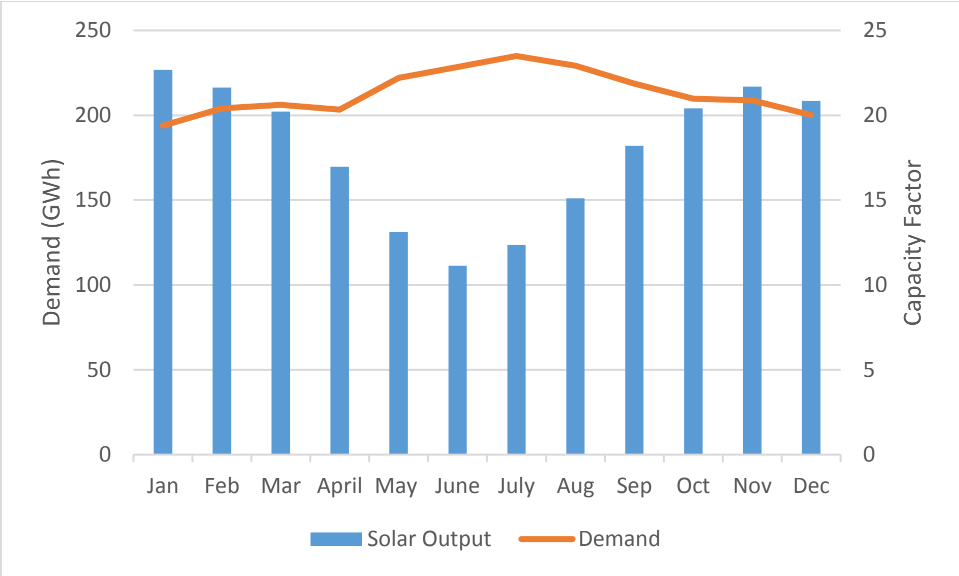


Figure 2. National average monthly solar power availability and average daily demand.

Figure 2 illustrates the national average hourly output of a 1kW panel for week days during different seasons. Again it is clear that there is less solar potential in winter due to a number of factors. The first is that there are significantly fewer sunlight hours in winter. As well as this, even when the sun is out it is at a lower angle in the sky with less direct incident solar power. The third factor is that the weather in winter is cloudier which also diminishes solar generation. New Zealand demand peaks in winter which suggests, in the absence of battery storage, solar power is not available when it is most needed. On the other hand, demand is higher during the day than at night which is factor which favours solar deployment.

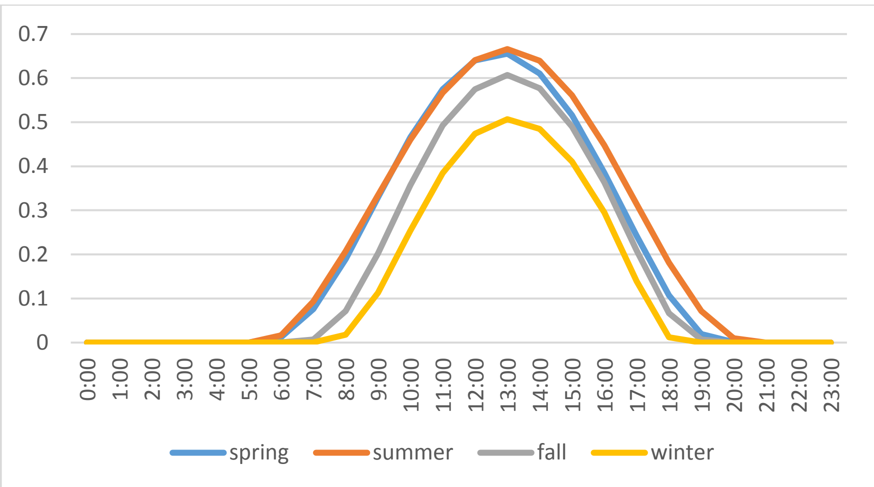


Figure 3. Average hourly national capacity factor during weekdays for different seasons (NZ daylight time).

With large amounts of installed solar the output profile of solar leads to the famous duck curve (California ISO, 2013) - with the net demand at a minimum during the middle of the day. Figure 3 illustrates the New Zealand version for installed capacities of approximately 9200MW and 4600MW[1]. As will be seen in section 4, with large amounts of installed solar prices are very low during daylight hours reversing the typical price pattern seen to date in New Zealand. Conversely the lack of solar generation during the morning and evening peaks in winter means other plants have to ramp up leading to high prices during these periods.

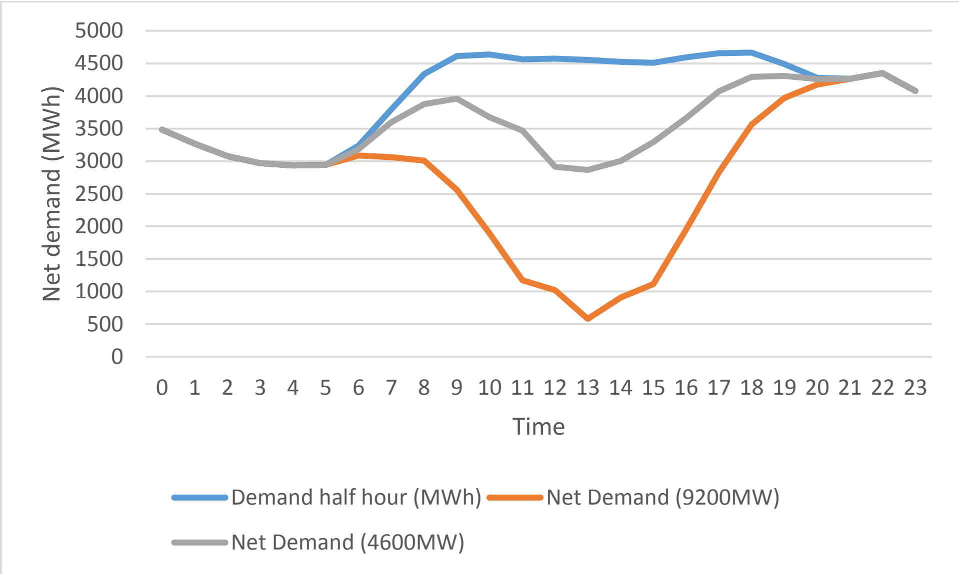


Figure 4. The New Zealand "duck curve". Net demand and demand for a typical day in summer (January 16, 2016)

To understand how solar output is related to demand we use demand data for the years 2003-2013 from the Electricity Authority (2016b). The raw data for each grid exit site needs to be aggregated for each half hour period. Following an approach suggested by Sinden (2007) demand data is matched with wind output for each time period and then arranged from lowest to highest demand. Average solar output expressed as a capacity factor for each demand percentile is plotted in figure 4. There is a strong correlation between demand and solar availability until approximately the 80th demand percentile when there is a steep decline in the solar capacity factor. During the highest demand periods solar is less and less available. For the top 10 percent of demand periods the average capacity factor is only 18%. This reflects the fact that the highest demand periods tend to be the evening peak in winter which is after or close to the time the sun sets.

[1] These installed solar capacities are used in the market simulation in section 4.

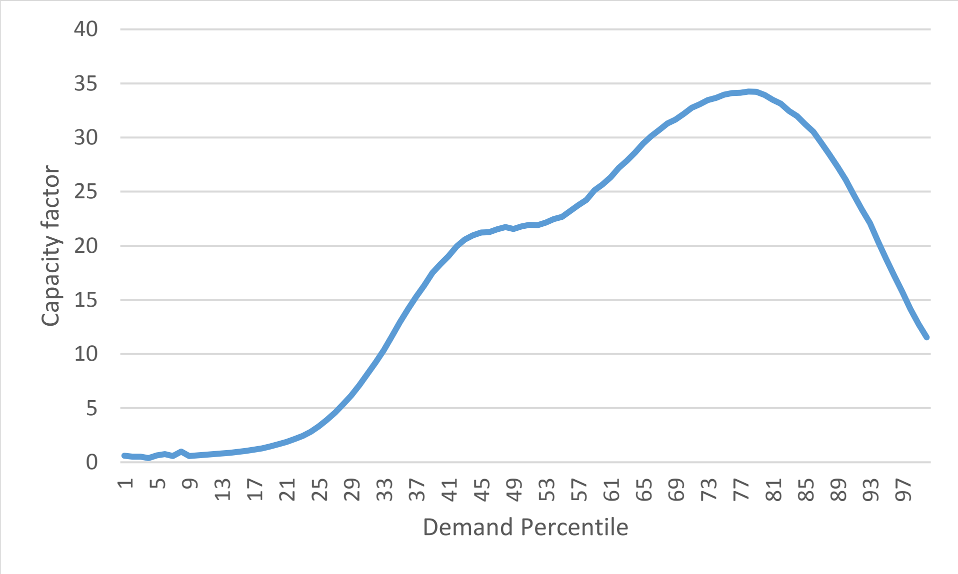


Figure 5: Average capacity factors for different demand percentiles

As well as the correlation between demand and solar availability it is also of interest to see how solar generation is correlated with inflows into the hydro dams which generate about 60% of New Zealand's electricity. The hydro dams have only limited storage – approximately 6 weeks generation at normal usage rates if there are no inflows. Some years there are low inflows in the period leading up to winter when the need for generation is highest. From winter onwards much of the precipitation falls as snow and so there are low inflows until the snow melts in spring. During years with low inflows sequences leading up to winter hydro generation is reduced during the months leading up to winter to conserve hydro generation potential which leads to water having a scarcity value and higher electricity prices (Tipping and Read, 2010). We used lake level and generation data from the Electricity Authority (2016b) to generate inflow data in GWh. Following one such "dry year" event in 2008 the New Zealand Electricity Authority commissioned an external review of dry year risk management and the performance of the electricity market during periods with low inflows (Isles and Hunt, 2008). The review identified a key time period, when considering dry year risk, of the inflow sequences from early November to mid-June. The graph in figure 5 is a scatter plot of cumulative inflows during this period compared to cumulative solar output for an assumed solar installed capacity of 9200 Mw. It can be seen that there is a correlation between low inflow sequences and increased solar generation. This means that potentially the increased solar generation could offset the lower hydro generation during dry years. However, the variation in solar inflows seems much less than the variation in inflows. For our assumed solar capacity, the variation in accumulated solar generation is 9000GWh compared to almost 47,000GWh for the inflow sequences.

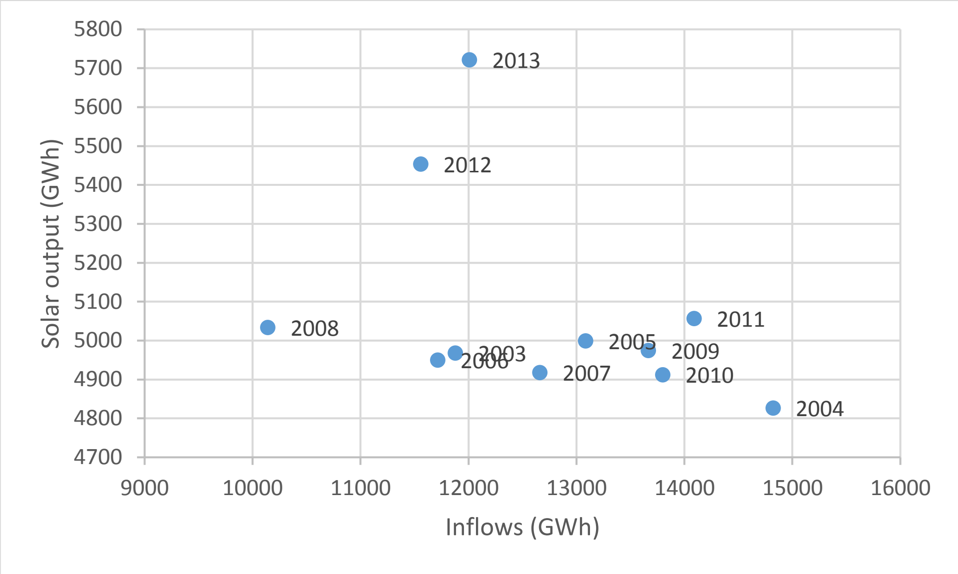


Figure 6. Scatter plot of Accumulated Inflows vs Accumulated Solar Generation for 9200 MW of installed solar.

Figure 7 plots the average solar capacity factor for each year that we studied. The difference between the year with the highest PV generation 2012 and the least is about +/- 8% of the long run average. The annual variability is potentially a concern although as seen there is at least some offset with low hydro inflows associated with high solar capacity factors

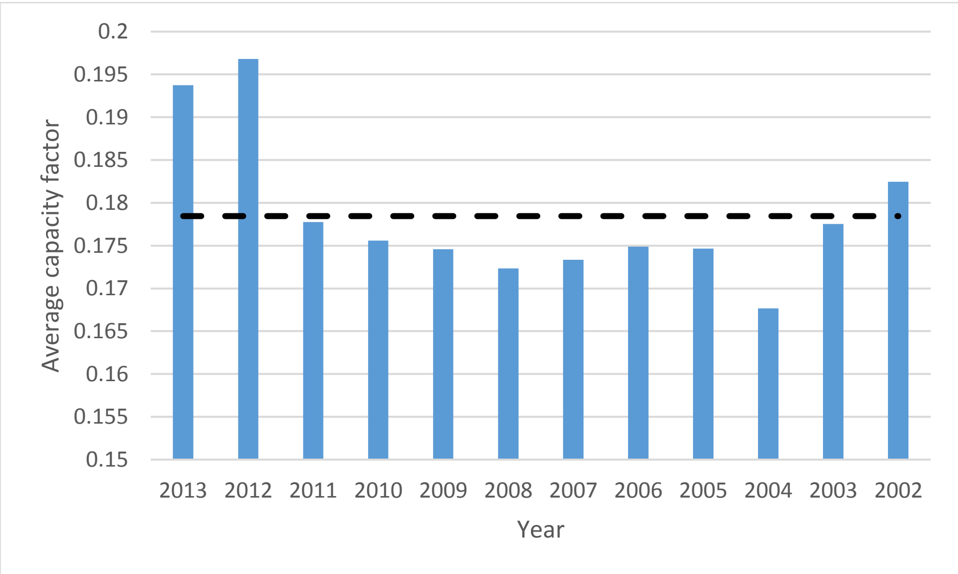


Figure 7. Yearly average capacity factors. The dashed line is the long run average.

3. Statistical Locational Analysis

So far we have looked at the overall picture using national demand and total installed solar aggregated with weights proportional to population size for the different regions. In this section we consider the geographical dimension. The New Zealand electricity market has locational pricing so it is natural to look at a regional analysis of the potential for solar generation. The first thing we consider is the output correlation between different locations as a function of difference (figure 9). As might be expected, the correlation decreases as a function of distance. Given that for much of the time it is dark everywhere in the country with output of zero everywhere, and hence perfectly correlated, the graph suggests very little correlation during daylight hours for distances over 600 km which could potentially have a positive market impact.

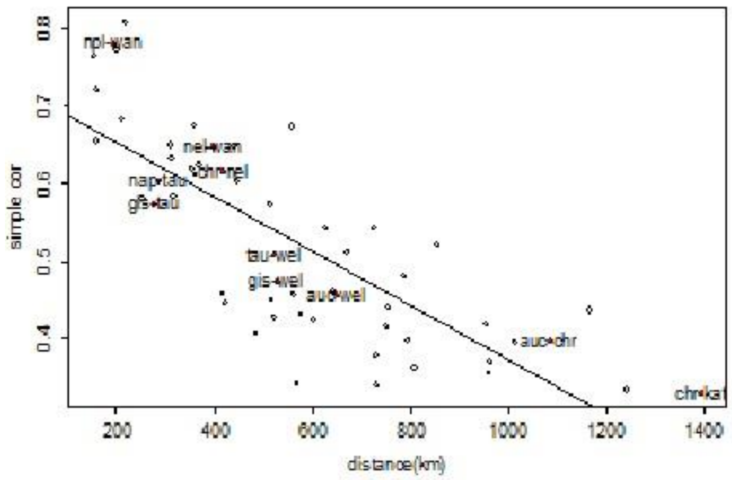


Figure 8. Correlation of solar output with distance

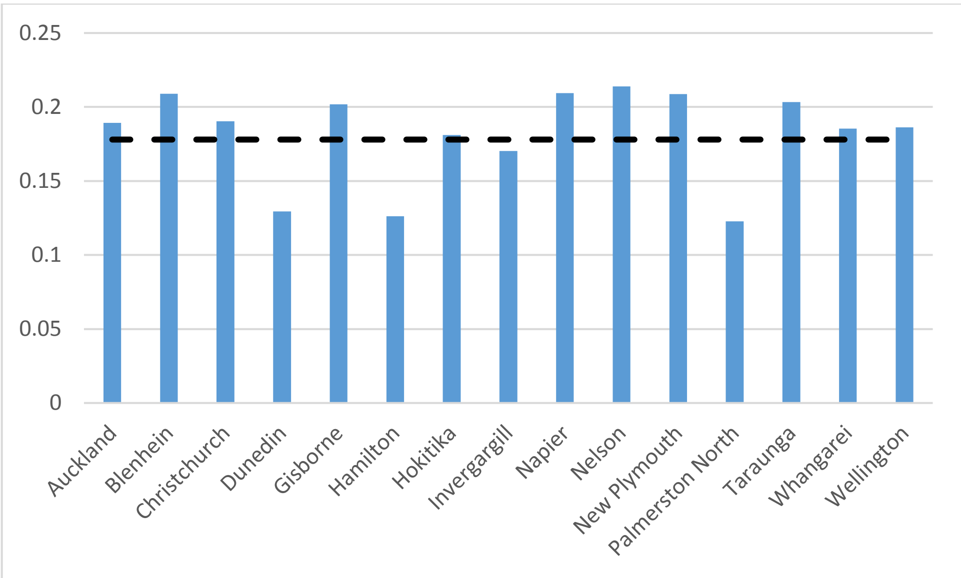


Figure 9. Average capacity factors for selected sites in New Zealand. The dashed line is the national average weighted by population.

Figure 9 shows how average capacity factors vary between regions. There is considerable variation – between 12% -21% - fortunately many of the high population regions have reasonable capacity factors and the population weighted average is near the top of the range.

To understand further the regional correlations of solar output demand, inflows and prices[2] we use a Fourier approach to distinguish between seasonal correlations and correlations of

[2] The nodal price data is from the Electricity Authority (2016b)

the anomalies. So for example if demand is unusually high does this mean that solar output is lower or higher for that time of year? This can help us understanding to what extent solar power is generated when needed. The Fourier analysis is naturally suited to analysing daily data rather than monthly or accumulated generation and inflows so in this section we use average daily solar generation, demand and prices. For the inflow data we differ a little from our analysis in section 2 – we use inflows into the four largest lakes of the Waitaki system namely (Tekapo, Ohau, Pukaki, and Benmore). Since these are around 90% of total national inflows it will be strongly correlated with total national inflows however some authors (Tipping and Read, 2010) argue that using the Waitaki inflows is a better approach so it seems worthwhile to investigate the correlations with these inflows as well as the national data used in section 2.

Each of our data points can be thought of as a fitted value (seasonal pattern) and a residual (anomaly) as is customary for regression analysis.

$$y_t = \hat{y}_t + \xi_t$$

We follow a specific form of time series modelling which is Harmonic or Fourier analysis. This is a widely accepted method to analyse climatic dependent variables that fluctuate in an interval of time -for example annually. Over shorter periods, data may have sharp jumps or drops due to unexpected conditions such as heavy rain or serious drought. Our technique of choice in this model is to apply a trigonometric Fourier function to capture seasonal trends in renewable energy sources and demand (Suomalainen et. al ,2015; Cox, 2006; Helsel and Hirsch, 1992; Bloomfield, 2004). To the best of our knowledge this modelling and analysis is new for solar energy, and for the hybrid system of hydro and solar power which we discuss in this paper.

We model the seasonal trend following Pollock (2009):

$$\hat{y} = \sum_{j=1}^{n} \{\alpha_j \sin(t*2\pi*j/T) + \beta_j \cos(t*2\pi*j/T)\}$$

$$T = 365, \mathrm{t} = 1,...,365, \mathrm{n} = 2$$

Data values used for the regression model above are averaged daily sunshine, hydro inflows, demand and price of electricity over several years. The parameter “n” is the order of the trigonometric function and set to 2. We have experimented with larger orders (e.g. n=3, 4) and found that the improvement in the fit to the data were negligible for n>2.

Clearly, the difference between the fitted model and data values provides the anomalies. Once we found the seasonal trend and anomaly of each series, we examine the correlation analysis between the seasonal patterns of variables as well as between the anomalies.

Table 1 shows that the correlation between the seasonal patterns of solar power and inflows into the Waitaki system is positive and relatively large. This is because inflows to the Waitaki River are lowest in winter, as precipitation is dominated by snow which does not melt until spring. However, as temperature increases from October onwards the snow thaws and the level of inflow increases (Fig 9). A negative correlation between resources would be favourable as it would mean that the two intermittent renewable generation resources were to some extent complementary. Unfortunately, this is not the case for solar PV in the hydro dominated New Zealand grid. Inflows to the hydro dams are low in winter and are high in summer as the snow melts. Solar generation is also lowest in winter and highest in summer – hence the strong correlation.

Sites	Daily Inflows		Daily Lake levels	
	Seasonal	Anomaly	Seasonal	Anomaly
Auckland	0.72	-0.07	0.23	0.00
Christchurch	0.74	-0.09	0.06	-0.01
Gisborne	0.74	0.02	0.12	0.00
Napier	0.74	-0.03	0.21	0.13
Nelson	0.69	-0.01	0.09	0.00
New Plymouth	0.69	-0.18	0.24	0.02
Tauranga	0.69	-0.16	0.31	0.00
Wanaganui	0.77	-0.09	0.30	0.02
Wellington	0.77	-0.10	0.24	0.01
Whangarei	0.72	-0.15	0.34	-0.02

Table 1. Fourier analysis of daily inflows, lake levels and solar generation.

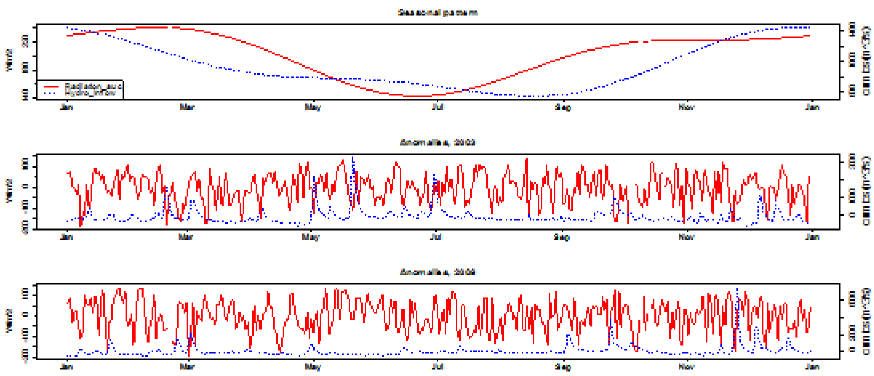


Figure 10. Seasonal pattern and anomalies for selected dry years.

Another approach to measuring the hydro availability is to use lake level data. We calculated the correlation between solar power and lake levels in the South Island in order to compare the results with the obtained correlation between inflows and solar power. The seasonal correlation between lake levels and solar power is also positive, but considerably smaller than the correlation between inflows and solar power. The reason for this is that the lake levels are managed, to some extent, so that going into winter there is enough stored water in the lakes to enable generation in winter when it is needed (demand peaks in winter in New Zealand).

The lakes are partly controlled by generation outflows decisions so the levels are partly endogenous. Consequently, we continue the rest of the study focusing on the hydro inflow instead of lake levels as these are more fundamental. Returning to Table 1 it can be seen that there is a negative correlation between the inflow and solar generation anomalies for most regions especially the large population centres which may have a positive impact on the market, however the negative correlation between the anomalies is not particularly strong.

Nodes	Solar power		Inflows	
	Seasonal	Anomaly	Seasonal	Anomaly

Auckland	-0.88	-0.01	-0.88	-0.02
Christchurch	-0.76	-0.11	-0.45	-0.11
Gisborne	-0.78	-0.06	-0.86	-0.03
Katatia	-0.72	-0.17	-0.74	-0.11
Napier	-0.84	-0.11	-0.90	0.02
Nelson	-0.89	-0.04	-0.88	-0.07
New Plymouth	-0.27	-0.03	-0.75	-0.03
Tauranga	-0.87	-0.02	-0.86	-0.03
Wanaganui	-0.96	0.08	-0.89	-0.15
Wellington	-0.92	-0.18	-0.86	-0.08
Whangarei	-0.72	-0.13	-0.74	-0.11

Table 2: Correlation of electricity demand with solar power and total hydro inflows

Table 2 shows the seasonal correlation and the correlation between the anomalies for different cities for solar output and demand. It quantifies the national information presented in figure 1. There is a strong anti-correlation between demand, which peaks in winter, and solar generation which is lowest in winter – not surprisingly this holds for all the major population centres. Although the pattern varies a bit for the different regions, overall there is a small negative correlation between demand and solar generation anomalies. Days which have higher than usual demand for the time of year also have lower than usual solar generation. A very similar pattern can be seen for the correlation analysis for inflows with demand.

Nodes	Solar power		Aggregated Inflows	
	Seasonal	Anomaly	Seasonal	Anomaly
Auckland	-0.35	0.00	-0.23	-0.15
Christchurch	-0.74	-0.01	-0.52	-0.18
Gisborne	-0.48	-0.04	-0.25	-0.15
Katatia	-0.40	-0.07	-0.24	-0.15
Napier	-0.46	-0.01	-0.26	-0.15
Nelson	-0.58	0.01	-0.51	-0.18
New Plymouth	-0.30	0.03	-0.30	-0.14
Tauranga	-0.30	0.00	-0.25	-0.15
Wanaganui	-0.45	0.03	-0.33	-0.15
Wellington	-0.46	0.00	-0.37	-0.15
Whangarei	-0.39	-0.05	-0.24	-0.15

Table 3: Correlation of electricity price with solar power and total hydro inflows

The seasonal correlations between electricity prices with solar power and hydro inflows are negative as summarised in the Table 3. The reason is that the price of electricity is relatively high from mid-autumn to the end of July as demand peaks; however, solar power and hydro inflows are low during this time. Again we see that the value of solar generation is lower than we would like to see in New Zealand. The price of electricity for all nodes is low when there is a lot of solar generation and high when there is little solar. Whilst there is a lower correlation between seasonal prices and inflows the correlation between deviations of inflows and prices is significant implying that when there are sudden spikes in the inflow levels; the price of electricity is lower than expected for the time of the year.

In brief, the correlation analysis between the seasonal patterns of solar and wind power with electricity demand and price shows that while demand of electricity is high and electricity is relatively more expensive neither solar nor hydropower are readily accessible.

We return now to the question posed by the graph in figure 5 – the relationship between inflows and solar output for dry years. The critical dry year periods correspond to low hydropower availability and coincide with large spikes in the electricity price. April to July is a critical time period as low inflows during this time will mean low lake levels going into winter where demand is high and inflows are always low. The jumps in the price of electricity and the high opportunity cost of hydro together with the relatively small storage capacities are among the main factors that make dry years a concern. Moreover, short run market power during dry years results in a less developed wholesale electricity market with lower degrees of efficient hedging which in turn shrinks the demand-side participation and the competition between retailers (Wolak, 2009). Managing dry year events better should improve the performance of the electricity market.

To analyse the correlation during the critical dry periods, we do not break down data into the seasonal pattern and the anomaly because this period lasts only four months. We consider the months April-July which broadly correspond to the phase 2 sequence of inflows identified as important by Isles and Hunt (2009)

Site	2003				2008			
	April	May	June	July	April	May	June	July
Auckland	-0.01	-0.60	-0.08	-0.23	-0.12	-0.40	-0.36	-0.19
Christchurch	-0.21	-0.31	-0.26	-0.20	-0.25	-0.22	-0.29	0.34
Gisborne	-0.07	-0.45	-0.33	0.05	-0.18	0.12	-0.16	0.12
Katatia	0.07	-0.48	-0.06	-0.15	0.09	0.27	-0.69	-0.24
Napier	-0.13	-0.45	-0.40	-0.13	-0.11	-0.09	-0.28	0.03
Nelson	-0.04	-0.45	-0.41	0.10	-0.18	-0.20	-0.36	-0.08
New Plymouth	-0.02	-0.52	-0.33	-0.28	-0.10	-0.33	-0.22	-0.20
Tauranga	-0.13	-0.58	-0.32	-0.14	-0.13	-0.13	-0.52	-0.08
Wanaganui	-0.24	-0.45	-0.01	-0.43	-0.14	-0.31	0.02	-0.38
Wellington	-0.16	-0.40	-0.40	-0.24	-0.35	-0.17	-0.10	-0.23
Whangarei	0.10	-0.41	0.03	-0.19	0.08	0.11	-0.60	-0.19

Table 4: Correlation between monthly solar generation and hydro inflow during dry years

Node	2003				2008			
	April	May	June	July	April	May	June	July
Auckland	0.29	0.25	0.40	0.22	-0.30	0.20	0.28	0.34
Christchurch	0.30	0.33	0.38	0.01	-0.37	0.17	0.32	0.12
Gisborne	-0.07	0.07	-0.11	0.30	-0.29	0.21	0.04	0.10
Katatia	-0.21	0.11	0.41	0.17	-0.07	-0.17	0.63	0.36
Napier	-0.05	0.17	-0.24	0.13	-0.19	0.31	0.17	0.29
Nelson	0.28	0.29	0.34	0.05	-0.20	0.18	0.39	0.38
New Plymouth	0.34	0.48	0.23	0.15	-0.23	0.15	0.27	0.33
Tauranga	0.12	0.18	0.53	0.24	-0.41	0.16	0.47	0.25
Wanaganui	0.12	0.47	-0.14	0.33	-0.27	0.46	-0.02	0.55
Wellington	0.16	0.48	-0.05	0.25	-0.11	0.16	0.06	0.28
Whangarei	-0.23	0.04	0.27	0.30	-0.16	-0.12	0.54	0.35

Table 5: Correlation between solar generation and price of electricity at each location.

The correlation results are summarised in the Table 4 and 5. They shows a negative correlation between solar power and hydro inflows indicating the possibility of employing solar power as an alternative resource for hydropower. More interestingly, the correlation between the price of electricity and solar power is mostly positive during the critical months during a dry year. This illustrates that although the level of solar power might not be significantly higher during these months, the positive correlation with price of electricity makes it valuable to capture more sun radiation, and compensate the lack of hydro generation. In this regard it may be advantageous to manage the angle of the installed panels at each location to ensure that a significant amount of solar is captured during these times even if overall energy generation is lower for the year as a whole.

4. Market Simulation

Our statistical analysis of the potential for solar has suggested some possible negative impacts on the market such as low availability during peak demand periods. The Fourier analysis confirmed the negative correlation between seasonal solar output and demand seen in figure 1 for all locations that we considered. We also saw a negative correlation between accumulated inflows and accumulated national solar output in figure 5. In section 3 we looked at the correlation between daily inflow and solar output during dry years. Overall there is a negative seasonal correlation between solar generation with demand and electricity prices for all locations reflecting the winter peak in demand pushing up prices. However, in most locations, during dry year events there is a positive correlation between solar output and prices during the months April-July which suggests that daily solar generation is highest on days with high prices during the critical months leading up to winter. Thus the value of solar output is high during such dry year events.

To understand the overall impact on the market we consider a number of scenarios with different amounts of solar generation for two dry years (2006 and 2008) and a wet year (2004). We calculate the long run capacity mix in the future using a capacity expansion model and then use a "solver" to simulate market prices on a simplified representation of the New Zealand market. We choose somewhat arbitrarily to run our simulations in 2025. The choice is dictated by the fact that we need detailed information on line capacities and much of the plans for line upgrades are in place. We also want to allow some time for the capacity mix to change as a result of the constraints we impose on the amount of installed solar. The "solver" solves for dispatch and wholesale prices based on marginal cost bids from the generators with one exception which is hydro where the bid also reflects the opportunity cost of water. The output is locational prices, dispatch, water values and lake storage levels This approach, with no market power, should give the socially optimum or competitive market outcome.

Following Tipping and Read (2010) we account for the opportunity cost of hydro generation during dry years by calculating a water value which is estimated as a function of the lake level compared to the historically average lake level on that day. We use here the estimation procedure outlined in Young et. al (2014). Hydro generators submit bids to the wholesale market at the opportunity cost of generation represented by the water value. There is an exception to this though, which is must-run hydro generation which bids in at a price of zero. Must-run is about a third of the total hydro capacity and includes run of river hydro and minimum dam spill rates set by regulation to ensure there are minimum flow rates in the downstream rivers. The simulation model also keeps track of generation outflows and inflows each day and updates the lake level and calculates a new water value which is used by the generators the following day. This allows us to capture the dynamic interaction of solar, hydro and the market over a year. Solar PV is most likely to reduce demand as households substitute solar production for buying off the grid. This is equivalent to not changing demand but instead mandating that solar production is offered into the market at a price of zero which is the approach taken here.

Since we don't have demand, wind, inflow and solar data for 2025 our scenarios are based on these recorded values for historic years with the exception of demand which is scaled upwards for each historic year by using projections for 2025 by the Electricity Authority (2010). The generation expansion model builds added wind capacity. Generation of wind used simulated data (NIWA, 2009) and followed the procedure used by Browne, Poletti and Young (2015).

The capacity expansion model we use is GEM 'Generation Expansion Model' developed by the New Zealand Electricity Authority (2016). The model takes as its inputs expected demand and generation operating and investment costs. It then builds the lowest cost new generation capacity needed to meet expected demand subject to a few security of supply constraints[3]. We would like to specify the different amounts of solar generation as a constraint for GEM however GEM does not model solar generation capacity, so instead we use wind as a proxy and force GEM to build a specified amount of wind generation capacity. We then take the extra wind farms out of the mix which are replaced by solar capacity which is set so that over the course of the year solar generates the same amount of energy as the wind generation it replaces. This seems like a natural choice as wind has similar characteristics to solar – it is offered into the market at a price of zero[4] and is intermittent. The geographic distribution of installed solar PV uses the weights for each region introduced in section 2.

A further constraint is included which is to force GEM to build total capacity so that the ratio of capacity to peak demand is the same as today's market. Browne et. al (2015) find that without this constraint GEM tends to build too much capacity forcing market prices down to unrealistic low levels. With this constraint market prices tend to have a similar long run price equilibrium which seems realistic from an investment point of view as the average market prices in the long run should be enough for baseload capacity, which runs all the time and hence receives the average market price, to break even.

Three different levels of wind integration are simulated; 1500MW, 4000MW and 6500 MW of wind respectively. The 1500MW scenario is the baseline scenario as this is the expected wind capacity in 2025. The other two scenarios replace the 2500MW and 4000MW of wind with the equivalent solar capacity. At these levels solar generation is increasing from about 0 to 48% of total capacity. Since solar has a relatively low capacity factor the total solar generation in our scenarios increases by less - from 0% to 19% of total electricity generation. TABLE 6 shows how the capacity mix changes as solar penetration increases.

Capacity Scenario	**Scenarios**		
Wind Capacity Scenario	Baseline	Medium Solar	High Solar

[3] See Browne, Poletti and Young (2014) for the operating and investment costs used by GEM.
[4] At least the way we model the solar.

Effective Capacity to Peak Demand Ratio	1.22		
Total Capacity	11667	15402	19137
Effective Capacity	10692		
New Hydro Capacity	324	199	108
New Geothermal Capacity	907	907	334
New CCGT	699	0	0
New Peaker Plants	1031	980	860
New Wind	891	891	891
Solar		4610	9220

Table 6: New Capacity built for the different scenarios

The simulated wind data that we use has been generated for only 5 years which limits our choice of which years to run market simulations. We would like to compare the market performance for a ‘dry’ year to a ‘wet’ year. Examining figure 4 we choose 2006 and 2008 meteorological conditions as ‘dry’ years and 2004 as a ‘wet’ year. The wind data for 2008 is only available up to the end of September but since it is one of the driest years on record we thought it was useful to simulate market for the first 9 months which the crucial period leading up to winter.

Figure 10 shows the demand weighted prices for different amounts of solar penetration for the different simulations. It is clear that demand weighted average prices increase with increasing amounts of solar for all years. However, for dry years the increase in prices is considerably higher. The data for 2008 is for the first 9 months of the year and not directly comparable to the other years but the average prices for this period show a similar pattern to 2006 – dry years exacerbate the negative impact that increasing amounts of solar capacity have on the market.

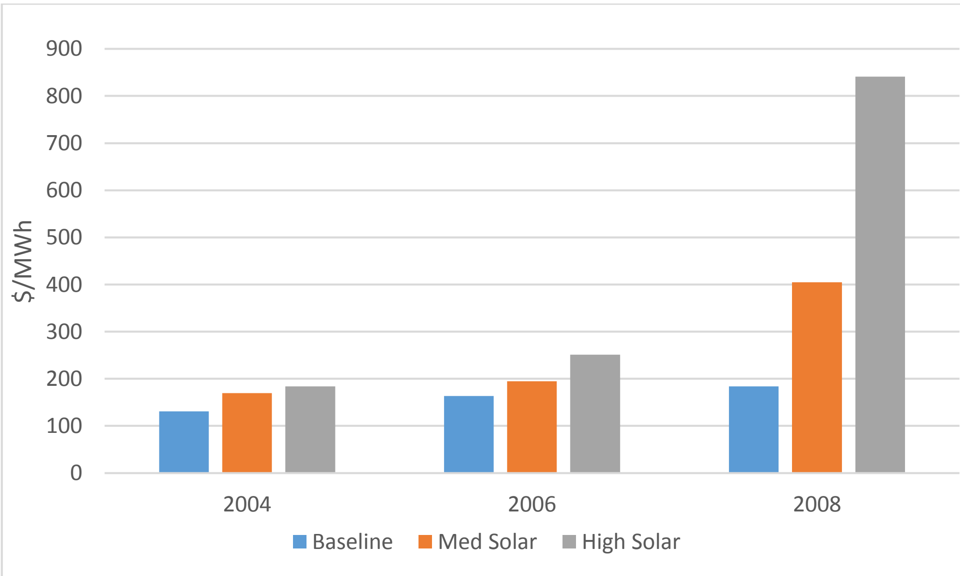


Figure 11. Demand weighted prices for different scenarios[5].

Figures 12 and 13 shows how the lake levels change during the year to help with understanding the reason for the differing market impact of increasing installed solar capacity. For both 2004 and 2006 solar does indeed substitute for hydro in the early summer however going into autumn and winter the capacity factor of solar decreases rapidly which means that the hydro generation or thermal generation has to substitute in terms of generation. For high solar penetration in the long run equilibrium there is less thermal capacity which puts more of a burden on hydro to make up for the reduced solar capacity factor in autumn and winter. This in turn means the outflows increase going into winter which leads to lower lake levels and higher prices. From spring onwards this reverses as the solar capacity factor increases going into summer. The net result of this is that the low solar capacity factors in the period leading up to winter, when demand is highest, has a negative impact on market prices - which here are the socially optimum prices. For a dry year the lower inflows exacerbate the negative impact that large amounts of solar have on the market. The main difference for the realatively lower lake levels for 2006 compared to 2004 is that the baseline capacity mix has an extra 699MW of thermal which for most of the first part of 2006 bids in at a price below the hydro (because the water value is high reflecting low lake levels) and hence adds to the total cumulative energy generated which means higher lake levels. For the first part of 2004 the extra thermal generation in the baseline scenario bids into the market above hydro and doesn't get dispatched. Note that for both years the reverse happens for spring and summer. As the capacity factor of solar increases less hydro is needed and the scenarios with solar see lake levels rise compared to the baseline with the result being that at the end of the year the lake levels are very similar for all the scenarios, however prices are much less price sensitive to the lake level as inflows exceed generation outflows.

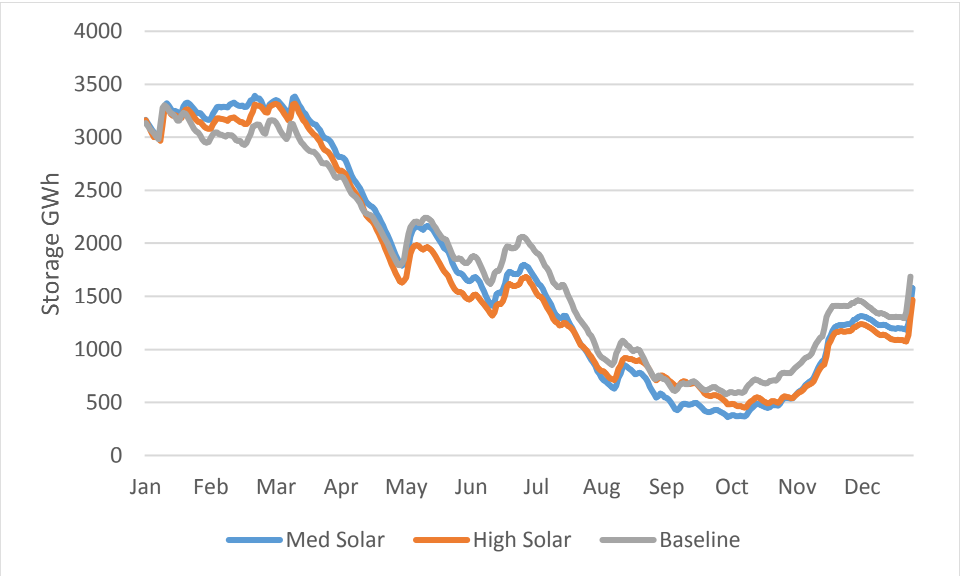


Figure 12: Lake Levels for 2004 meteorological conditions market simulations.

[5] The data for 2008 is for the first 9 months only.

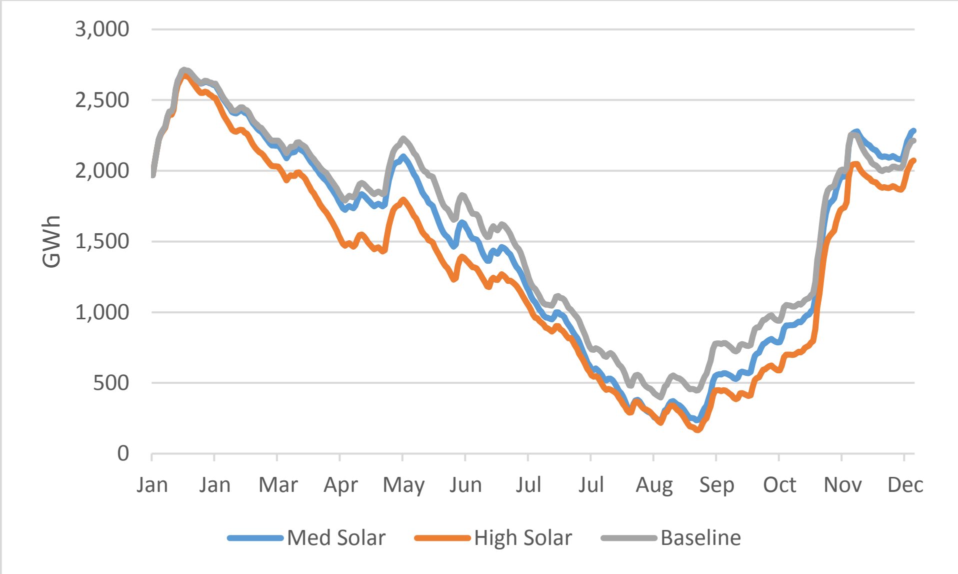


Figure 13: Lake Levels for 2006 meteorological "dry year" market simulations

Figures 13 and 14 illustrate how the changing lake levels impact on the market price. In 2006 prices start to increase earlier in the year and are much higher for the solar scenarios than the corresponding simulations for 2004 meterological conditions.

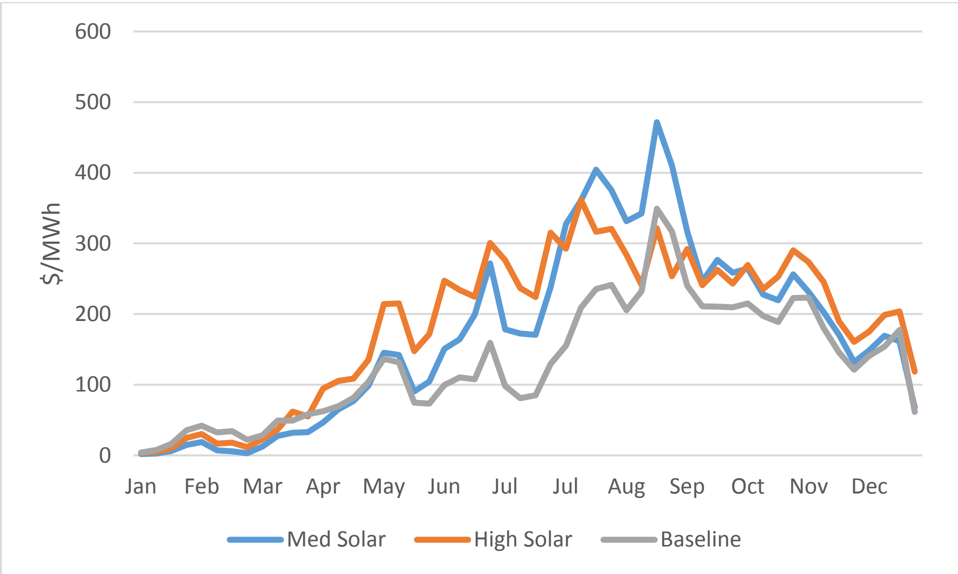
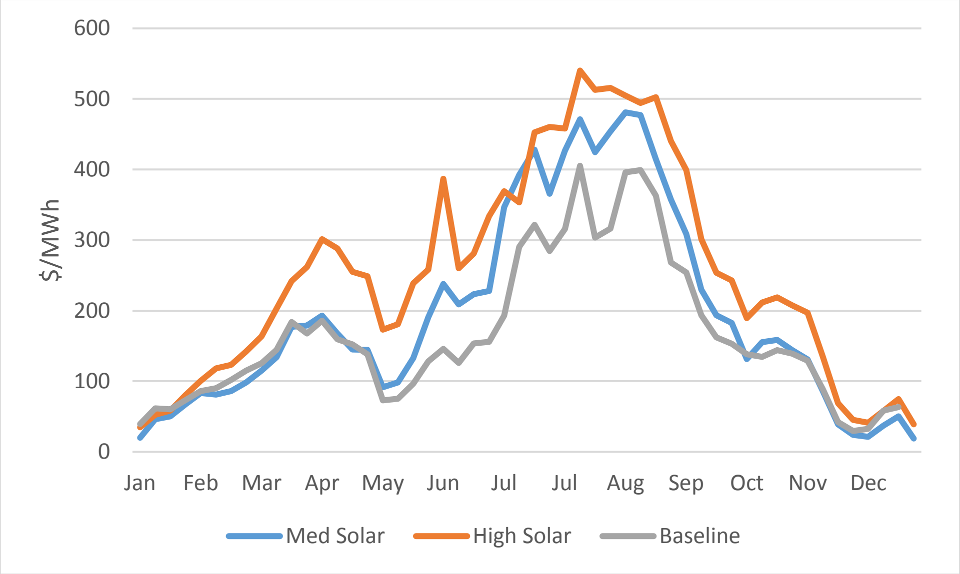


Figure 14. Average weekly prices for 2004 meteorological conditions market simulations



Significant

Figure 16. Average weekly prices for 2006 “dry year” market simulations

The analysis so far has concentrated on whether or not the increased accumulated solar output in the period leading up to winter during dry years can help. Unfortunately, the answer seems to be no due to the steeply declining capacity factors in autumn and early winter as demonstrated in figure 1. The other problem we identified in the statistical analysis is the lack of solar generation during peak demand periods in winter as seen in figure 4. The price duration curves (figure 15) for the half hourly simulated prices for 2006 do indeed show significantly more volatility as solar capacity increases - as would be expected for large scale deployment of an intermittent supply.

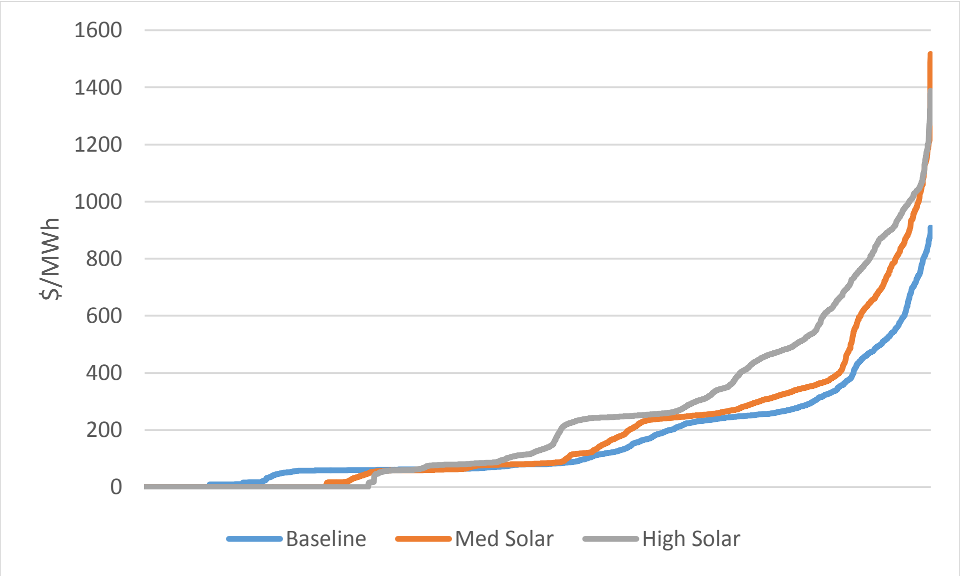


Figure 17: Price duration curve for 2006 meteorological conditions “dry year” market simulations

Figure 16 plots the average hourly price over the year and during winter for the high installed solar scenario. The average hourly price in winter is higher for each period in winter due to the combination of high demand and high water values. It is clear though that the morning and evening price peaks are exacerbated by the lack of available solar generation.

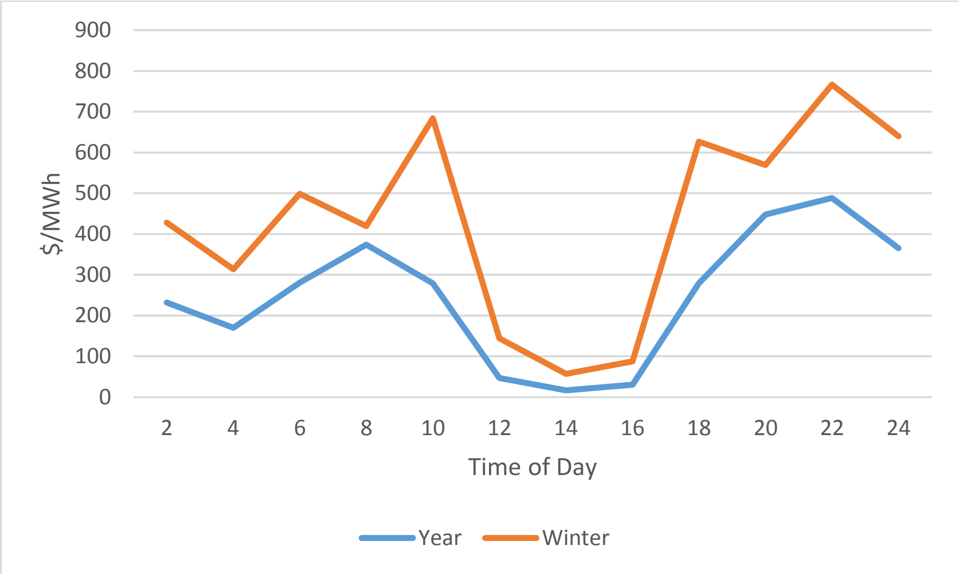


Figure 18. Average hourly prices over the course of a day.

One of the attractions of installing more solar is that it should help reach the government's target of 90% renewable electricity generation. Although the large amounts of extra solar capacity do increase the amount of renewable electricity the gain is not as much as one would have hoped for.

< Table 7 about here>

Table 7: Percent renewable generation

Looking at table 7 it can be seen that forcing in a large amount of renewable electricity generation in the form of solar PV hasn't increased renewable generation substantially. In 2006 renewable generation increased by about 5 percentage points from the baseline but increasing solar capacity further actually decreases the generation from renewables. In 2004, which is a wet year, there is a small increase for the high solar generation scenario. To understand why there is only a modest increase in renewable generation we examine dispatch for 2006. Dispatched solar for the medium solar scenario is 12% of total electricity generated. Doubling the installed solar for the high solar scenario increased solar dispatch to 19% generation – less than double as some is "spilled" as there is too much electricity generated at zero marginal cost. Looking at figure 17 it can be seen that increasing solar installed capacity from the medium to high solar scenario displaces other renewable energy generation such as geothermal, hydro[6] and wind. More peaking plant generation is required for the high solar scenario (again for the morning and evening peaks in winter) as well which is the reason why thermal generation increases slightly.

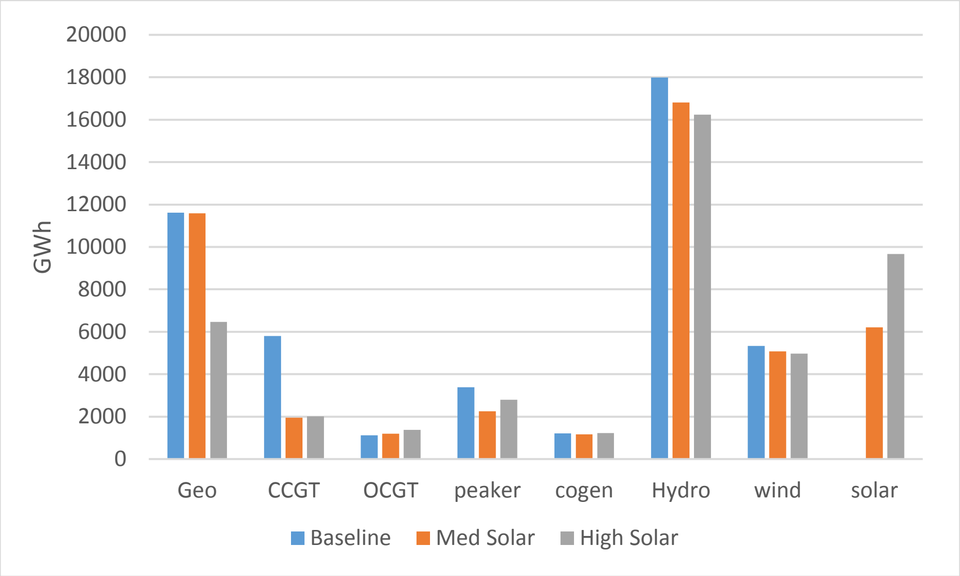


Figure 19. Dispatch by generation type for 2006 meteorological conditions

5. Conclusions and policy Implications.

The results of our statistical analysis and market simulation are somewhat pessimistic regarding the role that solar generation could play in the New Zealand electricity market. The strong negative seasonal correlation between solar generation and demand sees long run system costs increase as the amount of solar increases and displaces other types of generation. Furthermore, even though solar generation is higher in dry years this is not enough extra generation to offset the lower hydro availability.

Furthermore, the large increase in renewable solar PV generation does not have a commensurate impact on the overall amount of renewable generation as the energy is often delivered when it is not needed and results in renewable generation being spilled.

These results need to be interpreted with caution however. The reason for this is that higher prices would lead to more investment and a different long run equilibrium mix of generation. Whilst this is likely true the conclusion would still be the same as the new generation would increase the overall fixed costs of the system as opposed to the variable costs (including the opportunity cost of water) that we find in the previous section.

[6] Hydro dispatch includes dispatch from other hydro small hydro stations and run of river which aren't included in the lake level storage levels which see very little change between the different scenarios over the course of a year. It does not include dispatch from the Manapouri dam which is dedicated to supplying the aluminium smelter.

The other reason to be careful in interpreting these results is that both scenarios are constraining solar generation to be higher than is likely if it all comes from rooftop PV. This was a modelling choice to help in understanding the impact of solar PV on the market - and of course it is quite possible to have ground based solar PV installations.[7] Clearly more modest amounts of solar PV would have less of a negative impact on the market.

The policy conclusions of our analysis are pretty clear. There is no case for government policy to subsidise solar - for example feed-in-tariffs. It is likely that other forms of renewable generation such as wind (Browne et al., 2016)[8] and or geothermal will work better in the hydro based NZ grid. In further work we will examine to what extent solar and wind generation are complementary. It may be that it is optimal to have some solar as part of the expanded intermittent mix (including wind).

The other point to make is that in the short run as more and more solar PV is installed prices should decrease due to the merit order effect. Eventually other types of generation will exit the market however this could well take place over a number of years, particularly as the capital costs of current generation is a sunk cost and as long as the average price is above the existing plants variable cost they are likely to continue operating.

Finally, battery costs are continuing to decrease which could completely change the economics of Solar PV and the impact on the market in a decade or two.

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[7] Of course it is quite possible to have ground based solar PV installations, so the scenarios are certainly possible if the price of solar continues to decline dramatically.

[8] Note however that Browne et al (2016) use a constant water value and do not model the hydro system dynamically as we do here.

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Appendix A: Solar Data Preparation

The only available solar data is the solar radiation on the horizontal surface measured by pyrometers located in different parts of New Zealand and the measured data reported by NIWA. However, we are focusing on the absorption by the tilted rooftop PV modules. In this section, we explain the method to convert the global radiations on the horizontal plane to the global radiation on the inclined surface.

We calculate the global radiation[9] on the tilted plane for different incidence angles using the Olmo et al (1990) model. Notton et al (2004) examined the performance of different methods to calculate the solar radiation on the tilted plane from the solar irradiance on the horizontal surface. They found that Olmo model provides satisfactory results while requiring few input

[9] Global radiation on the tilted plane is the summation of the diffuse and direct radiation on the inclined surface. The Olmo model does not calculate the direct and diffuse radiation separately as what classic models did. Instead, it is a direct approach to calculate the global radiation with the aforementioned formula.

parameters. Based on the Olmo model, global irradiance incident on the tilted plane equals global radiation on the horizontal surface scaled by the geometric factor.

$$G_{\varphi} = G_h * \exp(-k_t(\varphi^2 - \theta_s^{\,2})) \qquad (1)$$

Where, G_h is the global radiation on the horizontal plane. φ is the scattering angle or incident angle which is the angle between normal of the tilted panel and sun radiation. We can also name this the zenith angle of the sun, k_t is the clearness index which is the ratio of the G_h to the hourly extra-terrestrial irradiation (Io) received on the horizontal plane. We utilise the well-known astronomic formula to calculate this proportion [46].

$$k_t = G_h / I_O \qquad (2)$$

$$I_o = I_{on} * \cos(\theta_s) \qquad (3)$$

$$I_{on} = I_{sc} * (\mathrm{r_O} / \mathrm{r}) \qquad (4)$$

I_{on} is the normal radiance and I_{sc} is the solar constant which is the radiation assuming comes to the Earth without the atmospheric impact while the Earth is in the mean distance from the sun. This is constant through time and has a negligible change through 4-5 years that is 1367 watt/m^2. r_o is the mean distance between the sun and Earth; it equals to one in astronomic unit which is 149,597,871 kilometres. r is the exact distance which varies throughout the year.

Furthermore, the incident angle is calculated using the formula as follow (Iqbal, 1983).

$$cos(\varphi) = cos(\delta) * cos(\mathrm{L} - \alpha) * cos(\mathrm{H}) + \sin(\delta) * \sin(\mathrm{L} - \alpha) \qquad (5)$$

Where δ is the declination angle, L is the latitude of each site, and α is the optimum angle of the panel from the horizontal surface (it is subject to the maximum absorption) and H is the hour angle.

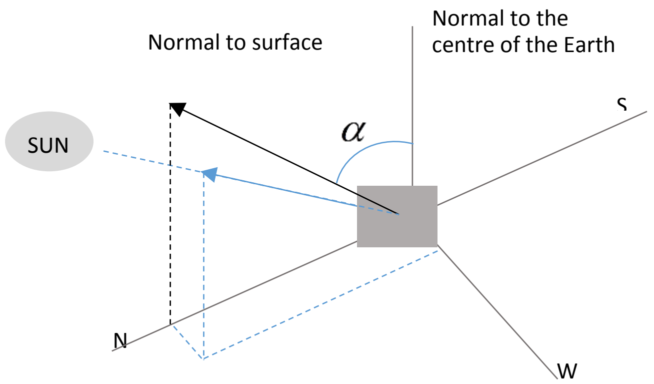

Fig. 1
Tilted angle for the facing North panel

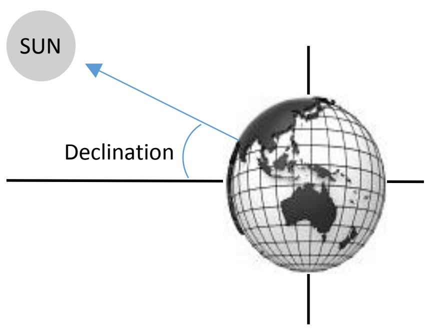

Fig. 2
Declination angle

Our analysis requires an assumption on the installation angle for PV panels. We capture the average monthly sun radiation from 2002 to 2013 to define the sunniest locations. We also consider major cities because of their large demand fulfilment out of their electricity nodes. Ultimately, we focus on 11 stations which broadly correspond to the largest population centres but also including some smaller sunnier regions, namely, Auckland, Christchurch, Kaitaia, Gisborne, Napier, Nelson, New Plymouth, Tauranga, Wanganui, Wellington, and Whangarei.

New Zealand is in the South hemisphere so panels mounted towards the North harness more sun radiation. Table A1 represents the optimum angle aiming to maximise solar power absorption. The optimal angle reported pertain to the selected stations. The optimum angle differs in each case from the standard approximation that the optimum angle is equal to the latitude due to the diffuse light component.

Station	Auc	Chr	Gis	Kat	Nap	Nel	Npl	Tau	Wan	Wel	Whr
Angle	41	50	44	40	44	46	44	43	46	47	40

Table 1. Optimum angles for the North faced PV- panels in different stations (degree)