The fair and reasonable value of exported PV output

Describing the methodology developed by ACIL Tasman for estimating the fair and reasonable value of exported PV output in South Australia

Prepared for the Essential Services Commission of South Australia

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ACIL Tasman

Economics Policy Strategy

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1 Introduction

The Essential Services Commission of South Australia (the Commission) is charged with protecting the long term interests of South Australian consumers with respect to the price, quality and reliability of essential services.

The Commission was given a new role in 2011 when the South Australian Government amended section 35A of the *Electricity Act 1996* (the Act).[1] The Commission now has the power to determine prices relating to "the feeding in of electricity into a distribution network".

In January 2012 ACIL Tasman assisted the Commission by estimating the value of electricity generated by a solar photovoltaic system (PV system) and exported to the grid (exported PV output). The Commission subsequently determined that in 2012-13 electricity retailers would pay 9.8 cents per kWh for exported PV output they received from their customers (the retailer payment).

In December 2012 the South Australian Government announced that, following a two year period of regulated retail electricity prices, electricity retail price regulation would cease. However, it is anticipated that the retailer payment will continue to be paid pursuant to the Act. Therefore, it is anticipated that the Commission will continue to determine the value of the retailer payment from time to time.

Against this background the purpose of this report is to summarise the methodology ACIL Tasman developed in 2011 and 2012 to estimate the fair and reasonable value of exported PV output.

This report is structured as follows.

Section 2 provides an overview of the policy context surrounding the Commission's inquiry and of the task itself. As discussed in this section, the task is to estimate the value of exported PV output to a retailer, and so some effects of PV systems on groups other than electricity retailers are excluded from our estimate of the fair and reasonable value to a retailer of exported PV output.

Section 3 discusses the sources from which retailers may derive value from exported PV output. There are a number of sources from which retailers may be thought to receive value but do not. These are discussed in Appendix A.

Section 4 provides a summary of the methodology and the inputs required.

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1 The relevant amendment Act was proclaimed on 28 July 2011.

The Commission has also sought advice regarding timing, which is provided in Section 5.

2 Overview

In 2008, the South Australian Government was the first in Australia to legislate a premium feed-in tariff for customers with PV systems. Under that scheme, small electricity customers who install PV systems on their homes were rewarded with a premium payment of 44 cents per kilowatt-hour (kWh) for electricity they export to the grid, approximately double the retail price of electricity.

Between 2010 and 2012, policy settings to support PV systems underwent significant change in South Australia and around the country. The cost of installing PV systems reduced and there were generous government assistance measures. Uptake grew rapidly.

More recently the general trend for Australian policy-makers was to transition from those generous (and popular) subsidies towards a more sustainable policy environment that offers a fair reward to owners of PV systems for the value they deliver to the energy system, rather than a 'premium' reward through government policy.

Consistent with this trend, the South Australian Government closed the original 44 cents per kWh 'feed-in tariff' to new customers from 1 October 2011. That tariff was replaced with a tariff of 16 cents per kWh for systems installed before 1 October 2013 (subject to transitional arrangements).

At the same time the Government took the view that, in addition to the premium payment paid through these schemes, PV customers should receive fair and reasonable compensation for the value of their exported PV output.

The purpose of the methodology described in this report is to assist the Commission's in determining the value of that compensation. This task arises from s.35A of the Act, which provides that:

> (1) The Commission may make a determination under the Essential Services Commission Act 2002 regulating prices, conditions relating to prices and price-fixing factors for—...
>
> > (ba) the feeding-in of electricity into a distribution network under Division 3AB;
>
> ...
>
> (2a) In addition to the requirements of section 25(4) of the *Essential Services Commission Act 2002* , the Commission must, in acting under subsection (1)(ba), have regard to the fair and reasonable value to a retailer of electricity fed into the network by qualifying customers within the meaning of Division 3AB.

...

There are two elements of s.35A(2a) central to the analysis presented in this report. These are:

1. the electricity to be valued is only that which is exported to the grid by qualifying customers (i.e. small energy customers)[2]
2. the value to be assessed is the value to a retailer.

Other groups are affected by the presence of PV systems and the payment for exported PV output. They include:

1. electricity generators
2. network operators
3. customers that do not own PV systems (non-PV customers).

However, the Act makes it clear that, in determining the value of the retailer payment, the Commission should exclude the impact on these groups and any others that may be affected. Therefore, the methodology described in this report excludes any potential value (or cost) to groups other than retailers.

Further, in estimating the fair and reasonable value of PV output, we have taken account of the fact that electricity retailers in South Australia are participants in the National Electricity Market (NEM). This means that any value they derive (or cost they incur) from exported PV output will be affected by the physical and regulatory arrangements associated with the NEM's operation. It follows that the procedures used in the NEM must be taken into account in estimating that value.

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2 For the purposes of Division 3AB of the Act, and therefore for our analysis, qualifying customers are small customers as defined in the Act. In South Australia, these are customers who consume less than 160 MWh of electricity per year regardless of whether they are business or residential customers.

3 Sources of value to retailers

This section provides a discussion of the various sources of value to a retailer of exported PV output. There are three sources.

First, electricity retailers buy electricity at the wholesale level and sell it to small customers.[3] When they receive exported PV output, the amount of electricity they must buy on the wholesale electricity market is reduced. This is the most significant impact that exported PV output has on retailers. It is discussed in section 3.1.

Second, exported PV output also provides value to a retailer by avoiding network losses involved in delivering electricity from remote generation sources. This is discussed in section 3.2.

Third, section 3.3 demonstrates that exported PV output allows retailers to avoid NEM fees and costs associated with the provision of ancillary services in the NEM.

There are a number of other factors that may be thought to contribute to the value to a retailer of exported PV output but which do not. These are discussed in Appendix A.

3.1 Reduced wholesale purchases

Wholesale electricity in the NEM is traded through a spot market. Generators sell electricity to retailers through a series of auctions run by the Australian Energy Market Operator (AEMO). The wholesale spot price of electricity is determined by those auctions.

The settlement process is used to determine the financial liability of each retailer on a daily basis. Settlement occurs weekly, four weeks in arrears, with AEMO collecting money from buyers of electricity and passing it on to generators. According to AEMO, "the settlement price for both generators and [retailers] is equal to the amount of energy produced or consumed multiplied by both the spot price that applies in the region of their operation and any loss factors that apply."[4,5]

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3 Retailers also supply large customers, but they are not eligible for the feed-in payments, which are limited to small customers and are thus not relevant to this analysis.

4 Australian Energy Market Operator, "An Introduction to Australia's National Electricity Market", July 2010, p12, available online at http://www.aemo.com.au/About-the-Industry/Resources/Market-Overviews, accessed 22 February 2013.

The spot price for each NEM region is calculated at a 'regional reference node' (RRN), which is a point in the transmission network at which notionally all wholesale sales and purchases of electricity are made. The adjustment for losses mentioned above is made in relation to the RRN, and prices quoted in the NEM are prices at that node rather than 'delivered' prices at the point of consumption.

The settlement process ensures that retailers buy electricity for their customers from the wholesale market at the RRN at the wholesale spot price that was in effect when their customers used that electricity. For this to happen, consumption needs to be 'matched' to the wholesale spot price, which changes half hourly.

To match consumption to the spot price and calculate each retailer's liability to buy electricity, AEMO must determine how much electricity each retailer's customers used in each half hour interval.

In South Australia, the vast majority of small customers have accumulation meters.[6] These are read periodically to determine how much electricity passed through them since the last reading. Accumulation meters are analogous to the odometer in a car.

With accumulation meters it is impossible to determine how much electricity was used in any given half hourly interval. Therefore, in South Australia (as in most parts of the NEM) it is currently impossible to match a small customer's actual electricity use to the wholesale price at the time of that use.[7]

Without detailed, half hourly consumption data, an alternative approach is necessary to match the amount of energy used in a given period with the corresponding wholesale price. In the NEM, this is done using a mathematical process referred to as profiling.[8]

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5 AEMO refers to market customers in the original and retailers are only one category of market customer. However, for present purposes the distinction is immaterial.

6 There are some exceptions, such as the approximately 2000 interval meters in use in a Solar Cities trial site. The number of exceptions may grow if new meters have interval capability even if that is not currently used in South Australia.

7 It is impossible in a practical sense. It could be done if all customers had interval meters, which record electricity consumption as a series of half hourly increments for exactly this purpose. However, these are not (widely) in use in South Australia.

8 Australian Energy Market Operator "Understanding load profiles published from MSATS", August 2009, available online at http://www.aemo.com.au/electricityops/nslp.html, accessed 16 September 2011

3.1.1 Settlement using profiling

Profiling is applied to the total amount of electricity sold in the NEM each day.

The starting point is all the electricity 'delivered' to the grid. Electricity used by customers with interval meters, whose consumption is known on a half hourly basis (and some ancillary loads[9]) is deducted. The residual is, by deduction, the amount of electricity that electricity retailers bought to supply small customers without interval meters.[10]

In South Australia, the profiling process also includes an adjustment, or 'peel off', for electricity used by controlled loads, most commonly electric water heaters. The controlled load peel off is calculated using sample meters and a 'controlled load profile'.[11]

The electricity that remains is deemed to have been used by small customers for general use (not controlled load). The remaining usage, which has been calculated on a half-hourly time-of-use basis, is the Net System Load Profile (NSLP).

A stylised example of the profiling process is illustrated in Figure 1 below.

Figure 1 shows the first four steps of the profiling process. The first pane shows a stylised example of electricity demand in South Australia for a single day. Demand is lower overnight than in the morning and rises to a peak in the afternoon before returning to a lower level overnight.

The second pane shows the same load broken into components. The commercial load category represents all customers with interval meters and the street lights category represents the various unmetered loads in the system. Controlled load (e.g. electric hot water) is shown separately from the other small customer load. The proportions of electricity used for these different purposes are illustrative; they are not intended to be indicative of actual use.

In the third pane commercial load and street lights have been removed leaving only small customer load.

Once the controlled load peel off has been done the residual is the NSLP, depicted in the fourth pane. This represents the demand for electricity of small customers other than for controlled loads such as water heating.

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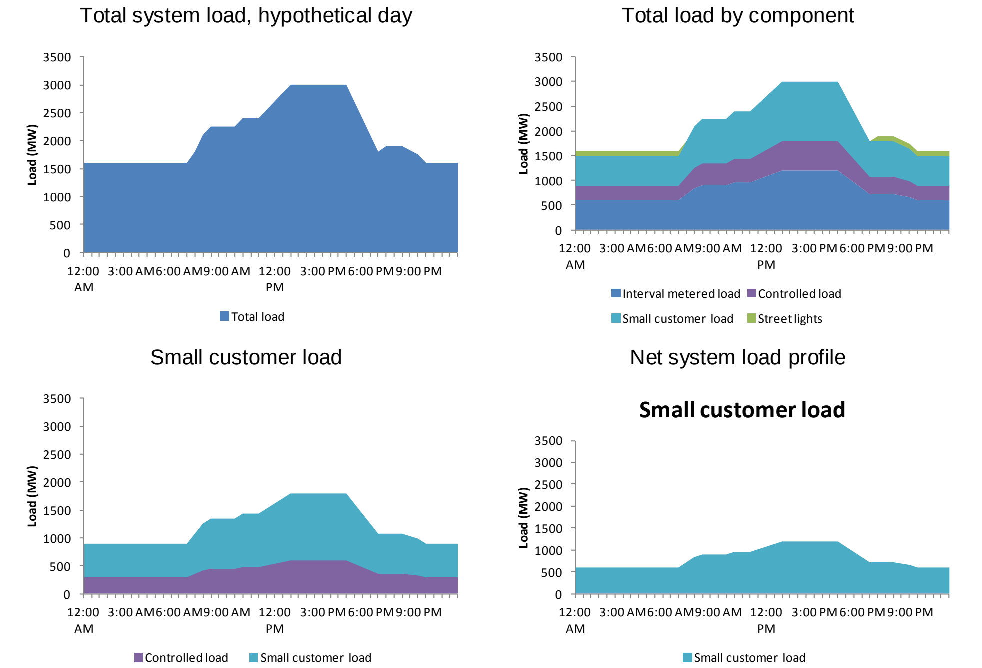
9 For example unmetered loads such as street lighting.

10 In South Australia this is all small customers.

11 AEMO 2009, op cit.

Figure 1 **Example of developing the NSLP for a hypothetical day**



The NSLP is then used to settle the purchase of wholesale electricity. The total quantity of electricity represented by the NSLP is allocated to individual customers and therefore individual retailers in proportion to the total amount of electricity that they consumed in the relevant period.[12] In doing this, it is assumed that each individual customer's 'load shape' is the same as the NSLP.

This is built up to determine each retailer's liability.

The NSLP used in the settlement process is a robust estimate of the residual loads in the system that has been used in the NEM since January 2001. It gives an accurate picture of the electricity delivered to the grid and supplied to all small customers in aggregate on a time-of-use basis. However, it provides no information regarding how much electricity an individual customer has used or when they used it.

3.1.2 How the Net System Load Profile is used to settle the market

Once the NSLP has been calculated for a given day, two more pieces of information are used to settle the market:

- the wholesale spot price of electricity in each half hourly period

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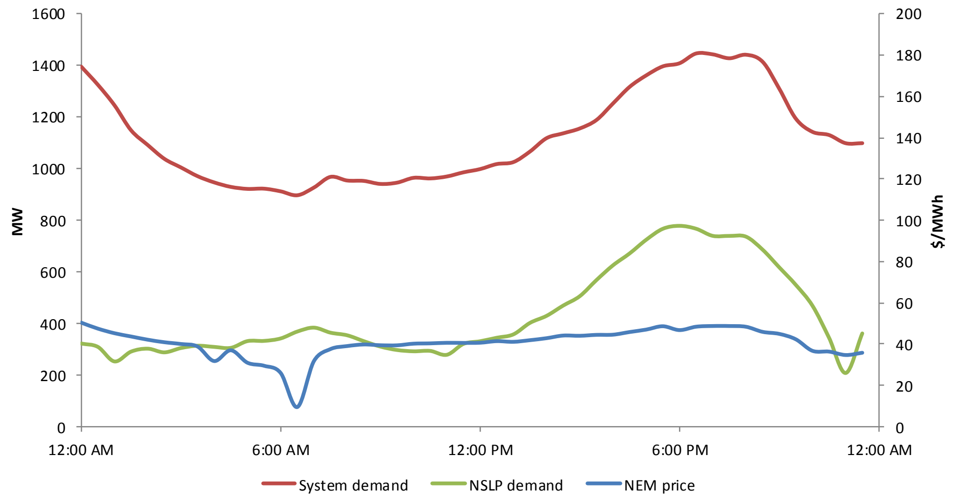
12 Small customers are typically billed every three months so a process is necessary to convert to daily consumption estimates.

- the total amount of electricity sold to the small customers of each of the 'tier 2' retailers. In South Australia, this means all retailers other than AGL.[13]

The settlement process is illustrated in Figure 2, which shows the total system load, NSLP and wholesale spot price for 11 November 2012, and Table 1, which shows the market share of each retailer.[14]

Figure 2 **System load, NSLP and spot price – 11 November 2012**



Data source: AEMO

Table 1 **Retailers' market shares**

Retailer	Market share (%)
AGL	51%
Origin Energy	18%
Powerdirect	2%
Simply Energy	10%
Energy Australia	12%
All others	7%

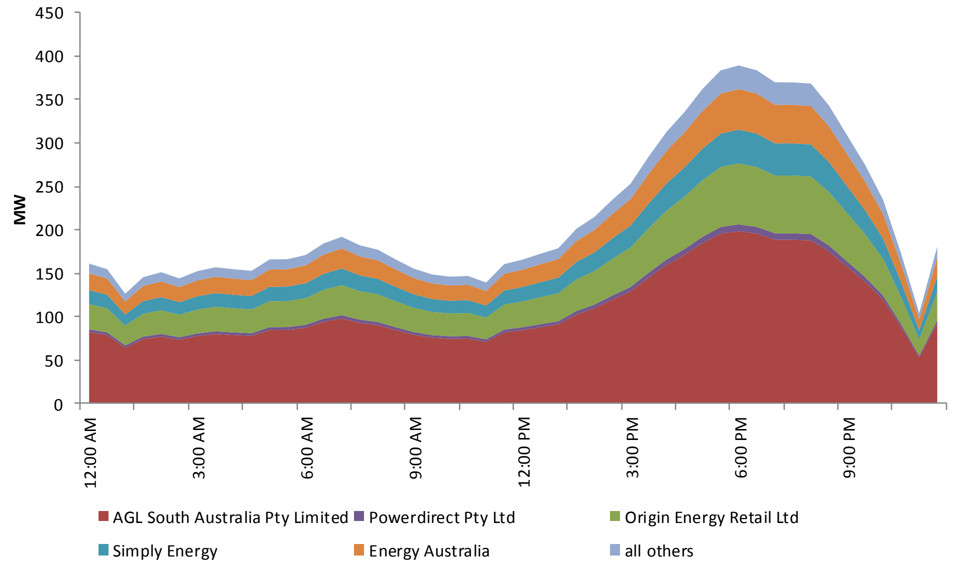
Data source: Essential Services Commission of South Australia, Annual Performance Report 2011/12, www.escosa.sa.gov.au

13 The liability of the tier 1 retailer, AGL in South Australia, is the remainder after the liabilities of other retailers have been netted off.

14 The data that are available publicly do not show how much of the total amount of electricity sold on the NSLP each retailer was required to buy (i.e. how much was used by each retailer's customers). For illustration purposes ***only*** we have assumed that their liability on that day was the same as their market shares as the Commission reported in its 2011/12 Annual Performance Report.

The market shares in Table 1 are applied to the NSLP in Figure 2 to show each retailer's 'share' of the NSLP in each half hourly interval, refer Figure 3. Each retailer's 'band' of liability is equivalent to the amount of electricity it sold all of its customers that day, allocated according to the NSLP.

Figure 3 **Retailers' estimated 'share' of NSLP on 11 November 2012**



On 11 November 2012, the total quantity of electricity sold on the basis of the NSLP was 10,399 MWh[15] and the total wholesale cost of electricity sold on the basis of the NSLP was $436,311.[16] The average wholesale price of electricity sold on the basis of the NSLP that day was $41.96 per MWh.

There are approximately 800,000 small customers in South Australia so the average wholesale cost of electricity that day was approximately $0.55 per customer.

Table 2 shows an estimate of the cost each retailer incurred on 11 November 2012 to purchase wholesale electricity on behalf of its small customers. For example, in this illustrative example we estimate that AGL's liability for electricity sold to its small customers on 11 November 2012 was approximately $231,245.

15 This is the area under the green curve in Figure 2.

16 This is the product of the blue and green curves in Figure 2.

Table 2 **Retailers' estimated 'share' of wholesale electricity cost on 11 November 2012**

Retailer	Wholesale electricity cost ($)
AGL	$231,245
Origin Energy	$78,536
Powerdirect	$8,726
Simply Energy	$34,905
Energy Australia	$56,720
All others	$26,179

Data source: AEMO, ESCOSA

On any given day, every electricity retailer in South Australia pays the NSLP-weighted price for every kWh of electricity they buy for small customers. Through the settlement process, the NSLP-weighted price varies daily to reflect fluctuations in the wholesale spot price and the actual timing of electricity consumption.

3.1.3 The impact of PV systems on the NSLP

As discussed in section 3.1.1, the NSLP is the residual amount of electricity demand delivered into the market after other interval metered or deemed loads have been taken into account. As electricity is not presently stored in meaningful quantities, it is also the amount of electricity that was generated for small customers in each half hourly interval.

When PV systems generate electricity, all else being equal, other generators produce less. Usually, the output of these other generators would fall by more than the amount of PV output because the PV systems are closer to where the electricity is used so less is lost in the network. The effect of this on the value of exported PV output is discussed in section 3.2 below.

From a generator's point of view, it does not matter whether the electricity generated by the PV system is used in the home or exported. Regardless of where it is used, the output of a PV system reduces the amount of electricity generators must produce.

The output of PV systems is not taken into account explicitly in determining the NSLP. From this perspective, the electricity they generate is the same as a reduction in demand. When PV systems generate electricity, less is required from other generators and the NSLP is 'reduced' by that amount. This is illustrated in Figure 4.

The first pane of Figure 4 reproduces the NSLP from 11 November 2012.[17]

The second pane shows the hypothetical output of a 'fleet' of PV systems. For illustrative purposes, to make the effect large enough to be seen easily on the charts, this fleet of systems was assumed to generate 5,000 MWh of electricity on 11 November 2012.[18] That output was apportioned across the day in line with the solar insolation measured at North-West Bend (on the River Murray about 180 km from Adelaide) that day. This data was sourced from Renewables SA,[19] which has made insolation data available for several locations in South Australia. Of these, North-West Bend is the closest to Adelaide.

The third pane shows what the NSLP would have looked like on 11 November 2012 if the hypothetical fleet of PV systems had been in place on that day.

As illustrated in Figure 4, the impact of the PV systems is that the NSLP is 'lower' whenever they are generating. The difference between the NSLP with and without the PV systems is the total output of the PV systems. The area between the two curves represents 5,000 MWh.

When the NSLP is reduced in this way there are two results:

1. the NSLP-weighted price will (usually) be lower than it would have been if the PV systems were not in place, even assuming NEM prices in each half-hour period are themselves unchanged (the price effect)
2. the total amount of electricity sold on the NSLP is reduced (the volume effect).

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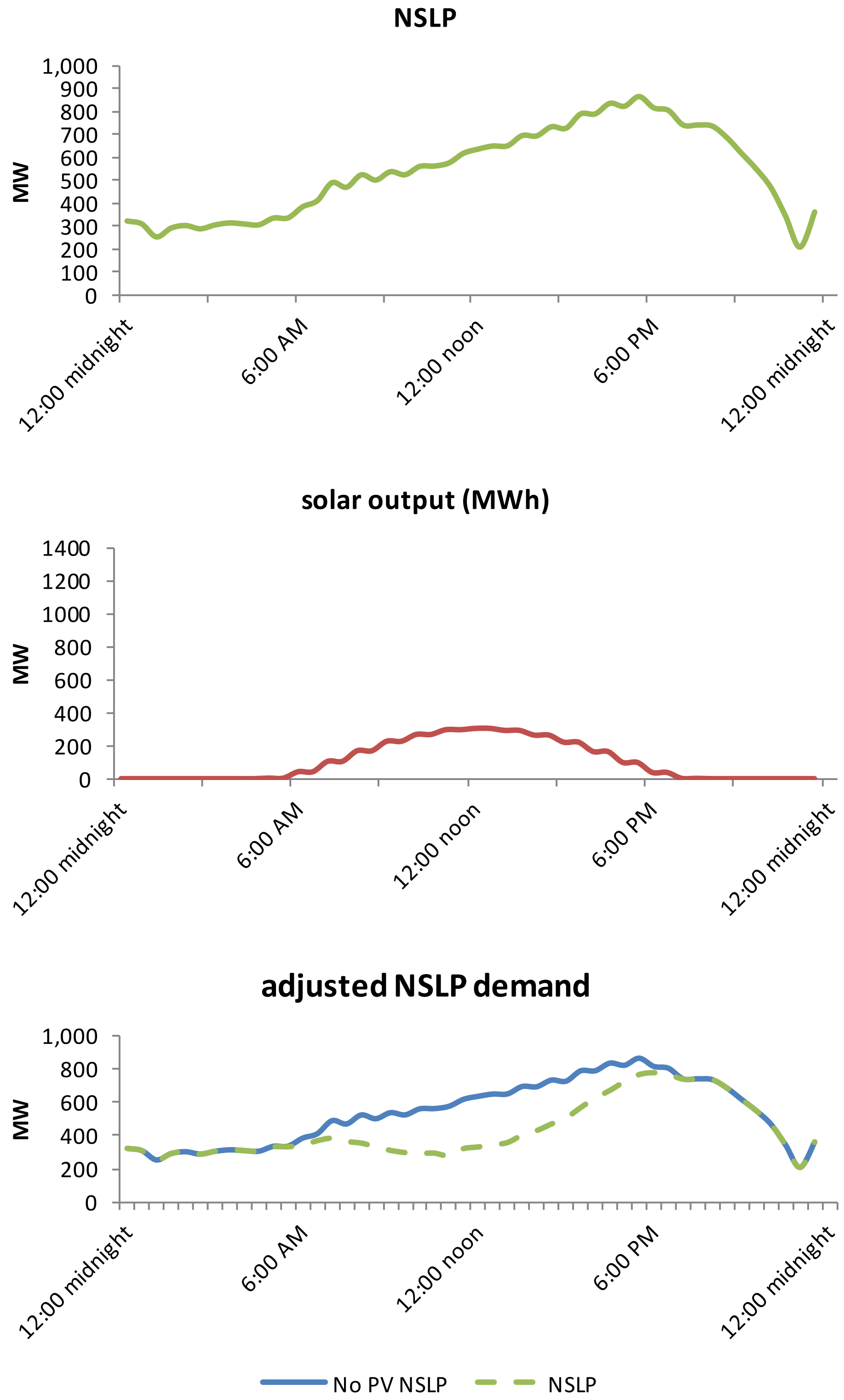
17 As this is the actual data from that day it already reflects the electricity generated by PV systems that were in place then. It is used here as a starting point for illustration only.

18 This is a very large fleet of PV systems presented only for illustration purposes. Between 12:00 and 12:30 PM, the PV systems were assumed to produce 305 MWh of electricity. To do this they would need a working capacity of almost 610 MW. Assuming an average system size of 2.5 kW systems, the fleet would need to include 244,000 individual systems all working at peak output. This would be more than one system for every four small customers in South Australia, and close to double the capacity of systems in place at the time of writing.

19 http://www.renewablessa.sa.gov.au/investor-information/resources#Solar

Figure 4 **Illustrative example of the impact of PV systems on the NSLP**



Source: ACIL Tasman analysis

3.1.4 The price effect

The price effect is the mathematical result of the change in the NSLP. Assuming that spot prices themselves do not change and that they are higher during the day than overnight, the NSLP-weighted price will be decreased due to the output of PV systems. [20]

All else being equal, the output of PV systems reduces the price that retailers pay for wholesale electricity for small customers. This affects all retailers equally and is caused by the total output of the PV systems, not (only) the quantity of electricity that is exported.

However, in a competitive retail market such as South Australia's, the value of the price effect will not be captured by retailers. Rather, the operation of the market will ensure that the price effect is passed through to customers. Therefore, we have excluded it from our estimate of the fair and reasonable value of exported PV output.

3.1.5 The volume effect

When PV systems generate electricity they reduce the amount of electricity that retailers must buy in two ways.

First, the PV output that is used in the home reduces the quantity that the PV customer buys from their retailer. Therefore their retailer need not buy as much to supply them. From that retailer's point of view, the PV system has the same effect as if the customer decided not to use as much electricity.

The benefit of any in-home use of PV output accrues directly to the PV customer, who benefits by not buying that electricity at the retail price. This part of the volume effect provides no benefit to the retailer.

Second, the exported PV output alters the retailer's 'share' of the NSLP. Therefore, in the settlement process, retailers do not buy as much electricity as they would have if the PV systems had not generated electricity, as is explained below.

Continuing with the above example, the impact of the hypothetical fleet of PV systems on settlement on 11 November 2012 is summarised in Figure 5.[21]

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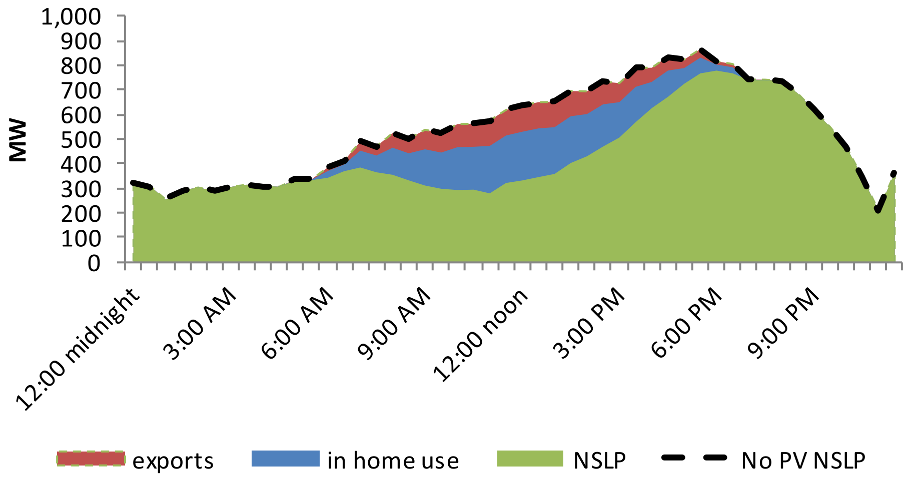
[20] The reason that the price effect reduces the NSLP weighted price of electricity is that PV systems generate during the day. The NSLP-weighted price after allowing for generation by PV systems reflects a relatively higher amount of cheaper overnight electricity and a relatively lower amount of more expensive daytime electricity than it would without them.

[21] It is assumed that the fleet of PV systems is spread among retailers in accordance with their market shares.

Figure 5 **Illustrative example of the NSLP adjusted by PV output showing in-home use and exports**



In Figure 5, the (green) area under the NSLP curve is the total quantity of electricity generated by generators other than the hypothetical fleet of PV systems described above.[22]

The (red and blue) area above the NSLP curve is the quantity of electricity that was generated by the hypothetical fleet of systems. For illustrative purposes we have assumed that 35 per cent of this electricity was exported to the grid (red) and the remainder used in the home (blue).[23]

If there were no PV systems in place, the NSLP would follow the dashed line.

When the market settles with the PV systems in place, retailers will need to purchase their share of the electricity represented by the green area. Assuming that the hypothetical fleet of PV systems is spread evenly across retailers then the proportions will be the same as in Figure 3 above.

However, there is also the electricity in the red area. Retailers will not purchase this electricity from the wholesale spot market, but they will sell it to their customers. This is true in aggregate and also for individual retailers because the electricity exported from any given customer's PV system is assigned to that customer's retailer.

22 The NSLP upon which this example is based already reflects the output of the PV systems that were in South Australia on 11 November 2012.

23 Aggregate data regarding the total quantity of exported PV output exports are available, but data regarding total production (i.e. including in-home use) are scarce. Therefore this ratio must be estimated. The 35 per cent estimate itself does not affect the point being illustrated. It does not affect the estimated value of exported PV output.

Therefore, due to the volume effect, exported PV output reduces the amount of electricity that retailers must buy on the wholesale spot market to supply small customers. The amount by which this is reduced is related to the quantity of exported PV output as well as network losses, which are discussed in section 3.2.

Retailers benefit from exported PV output. It reduces their need to purchase electricity from the wholesale market. The quantity that an individual retailer's 'own' customers export is captured by that retailer. It follows that the value captured by the retailer is the volume of exports from its customers, multiplied by the NSLP-weighted spot price.

3.2 Avoided losses

The amount of wholesale electricity displaced by exported PV output will usually be more than the exported PV output. This is because exported PV output is not transported from a remote generator to the 'grid'. That is, it does not travel over either the transmission or distribution[24] network and is not subject to network losses. If wholesale electricity incurs losses that are ten percentage points higher in reaching the point of consumption than exported PV output, 90 kWh of exported PV output would displace 100 kWh of wholesale electricity purchases.

Given this assumed loss rate, it follows that the value to a retailer of 90 kWh of exported PV output is equal to the value of 100 kWh of wholesale electricity, and therefore its per unit value to the retailer will be approximately 10% higher.[25]

However, electricity retailers buy electricity at the RRN. Therefore, while exported PV output may reduce losses between the generator and the RRN, the benefit of this is captured in the spot price the retailer avoids, which itself reflects losses incurred between the generator and the RRN.

Consistent with this, ACIL Tasman's projections of wholesale electricity prices relate to the wholesale electricity price at the RRN.

By contrast, retailers do benefit from the reduction in losses in the transmission system between the RRN and the connection point of the

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24 The statement regarding distribution losses is a simplification. How far the electricity generated by the PV system travels is a fairly hypothetical question given the complexities of power flows. However, from a financial point of view this is sufficient because the exported PV output is not subject to a deemed distribution loss factor.

25 Mathematically it is higher by 1/(1-10%).

distribution network, and within the distribution network itself. For a retailer to supply 100 kWh to its customers, it must buy more than this at the RRN. These losses are included in the value of exported PV output.

There are two components of losses relevant to the value to a retailer of exported PV output. The first is measured by the distribution loss factor (DLF). This reflects losses on the distribution network between the customer and the point where that network connects to the transmission network. The second is measured by the Marginal Loss Factor (MLF) this reflects transmission losses 'downstream' of the RRN between the RRN and the various transmission network connection points in a region.

Actual losses may be higher during the day, when PV systems are exporting, than overnight. However, the settlement process of the NSLP 'smears' the effect of loss factors across the day so that the average (published) loss factors are applied in practice. Therefore it is the published, not actual, losses that are relevant in estimating the value to retailers.

We have assumed that increasing penetration of PV systems will not alter loss factors over the projection period. If this happened, any benefit from reduced (system-wide) losses would be reflected in lower electricity purchase costs for all retailers and thereby tend to be captured by consumers rather than retailers, as discussed in section A.7.

3.3 Market and ancillary service fees

AEMO levies two sets of fees on energy consumers in the NEM. The first covers its general operational costs (market fees). The second covers the cost of various ancillary services that are provided to ensure the reliable operation of the system (ancillary service fees).[26]

3.3.1 Market fees

Market fees are published annually in advance and are generally levied on market customers (including retailers) on a per megawatt-hour basis.[27] They are published each year in approximately late May. For financial year estimates of the fair value of exported PV output we adopt the actual fees to apply in the year in question unless the projection is prepared before they are published. In this case, we assume that fees will not change in real terms from one year to

[26] These deal with issues such as frequency control.

[27] Other fees, such as for the registration of market participants, are levied on a user-pays basis, rather than on market customers specifically.

the next and apply the previous year's fees escalated at 2.5 per cent to account for inflation).

Consistent with this, for estimates other than financial years we apply the most recently available financial year escalated as appropriate.

3.3.2 Ancillary service fees

Unlike market fees, AEMO seeks bids from market participants to provide ancillary services. Ancillary service fees are then set on a cost-recovery basis.

Ancillary service fees in South Australia are generally in the range of $0.1 per MWh to $0.2 per MWh. However, they can spike to much higher levels

Given this variability, we assume that the three year average level of ancillary service fees reflects the likely future level of these costs.

4 The methodology and inputs

As discussed in chapter 3 our view is that the value to a retailer of exported PV output is:

1. the wholesale spot price of electricity projected using *PowerMark* as described in section 4.1
2. *weighted by* the net system load profile projected using the process in 4.2
3. *adjusted for* distribution losses
4. *adjusted for* market and ancillary service fees.

An illustrative example of the calculation is provided below.

For the illustration, consider ten periods in which the wholesale spot price of electricity and the NSLP were as shown in columns A and B of Table 3 (the values themselves are hypothetical).

Table 3 **Illustrative example**

	A	B	C
Period	Spot price	NSLP	A*B
hour	$/MWh	MW	-
1	$70.69	100	7069
2	$74.50	105	7822
3	$66.80	110	7348
4	$64.00	105	6720
5	$65.88	115	7576
6	$73.78	120	8854
7	$72.30	125	9038
8	$74.50	120	8940
9	$96.90	110	10659
10	$100.01	100	10001
Sum	-	1110 (E)	84028.58 (D)
	NSLP weighted average spot price	D/E	$75.70

Table 3 shows that, in this illustration, the NSLP weighted average spot price of electricity is $75.70/MWh, or 7.57 c/kWh.

To this we add estimates of the value of avoided market fees, ancillary service charges and distribution losses. If we assume for illustrative purposes that these equal 1 c/kWh in total, the estimated fair value of exported PV output is 8.57 c/kWh.

Therefore, to produce an estimate of the value to a retailer of exported PV output we require projections of each of the four items described above. Our methodology for producing those projections is described in the following sections.

4.1 Projecting the wholesale spot price of electricity

Our projection of the wholesale spot price of electricity is taken from *PowerMark*, ACIL Tasman's proprietary model of the NEM. *PowerMark* effectively replicates the AEMO settlement engine, NEMDE (National Electricity Market Dispatch Engine). It does this using a large-scale linear program based solution incorporating features such as quadratic interconnector loss functions, unit ramp rates, network constraints and dispatchable loads. The veracity of modelled outcomes relative to the AEMO NEMDE has been extensively tested and exhibits an extremely close fit.

That projection is in hourly resolution, that is, demand and spot price are projected for each hour of the projection period individually, which reflects the operation of the NEM itself.[28].

There are many inputs to *PowerMark*, covering all aspects of the NEM and including AEMO's electricity demand projections. ACIL Tasman routinely keeps *PowerMark* up to date as these inputs are available.

Key among these is the likely future demand for electricity. This is used *PowerMark* in terms of both maximum demand (MW) and energy sales (GWh). Rather than preparing growth projections in house, *ACIL Tasman* relies on projections published by AEMO. The presentation of those projections has changed somewhat in recent years. In the past they have been published in the South Australian Annual Planning Report which was an input into the (electricity) statement of opportunities. With the establishment of AEMO and its incorporation of the Electricity Supply Industry Planning Council, the projections were published in the South Australian Supply and Demand Outlook. In 2012 they were first published in the National Electricity Forecasting Report (NEFR).

We understand that in future the 2012 model will be followed. That is, AEMO will first publish electricity demand projections in the NEFR at approximately the end of June each year.

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[28] The NEM operates on half-hourly dispatch intervals. However, for most purposes our experience is that hourly modelling is sufficiently detailed.

4.2 Projecting the NSLP

Our projection of the NSLP is derived by estimating the relationship between the NSLP load and the regional (South Australian) load over the calendar years 2008 to 2010.[29]

There are four steps, which are discussed in turn below:

1. estimate historical demand for electricity by:
   a) small customers
   b) all South Australians (NEM)
2. estimate a relationship between small customer and regional (NEM) demand
3. use the relationship estimated in 2 above and a projection of regional (NEM) demand to develop a projection of small customer demand for electricity
4. adjust the projection developed in 3 above to create a projection of the NSLP.

4.2.1 Historical demand for electricity

AEMO publishes both the NSLP and South Australian (NEM) regional demand on a half hourly basis. However, neither accounts for electricity generated by PV systems. The first step in our approach to projecting the NSLP was to adjust for this.

The adjustment is a done by estimating the total amount of electricity generated by PV systems in each half hour of the historical period and adding it to both the NSLP and NEM regional demand data.

Our estimate of the output of solar panels is developed based on two inputs:

1. solar insolation data for North West Bend developed by 3TIER for Renewables SA.[30]
2. solar PV uptake data provided by SA Power Networks, which we project on a straight line basis into the future.[31]

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[29] The approach described here is fundamentally different to the approach we used to project the NSLP in our earlier estimate of the value of exported PV output, though the results are not substantially different. This is the only difference between the two methodologies.

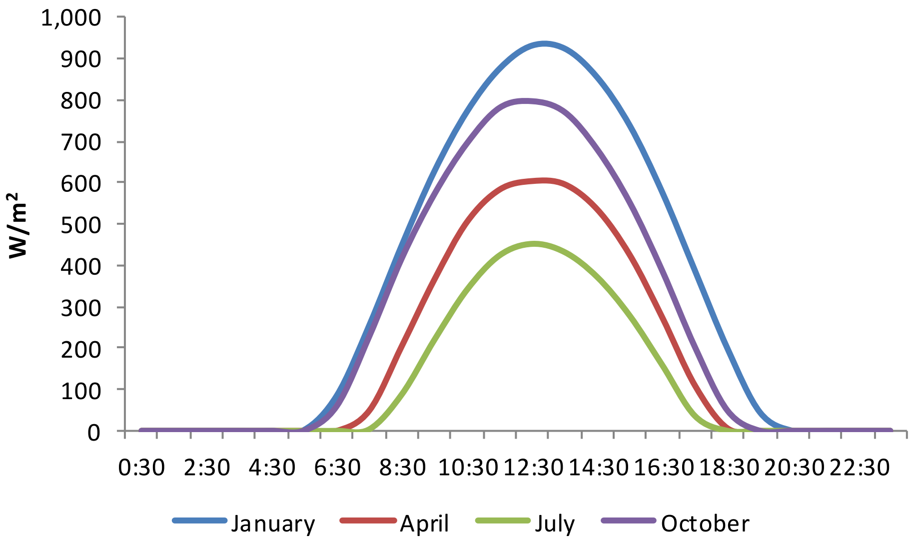
[30] See Renewables SA, Renewable Energy Resource Maps available at http://www.renewablessa.sa.gov.au/investor-information/resources#Solar

[31] That is, we assume that the quarterly rate of uptake of PV systems in future will be the same (on average) as it was in the first half of the 2012/13 financial year. We also assume that uptake is spread evenly among the three months in each quarter.

We also assume that the total output of a PV system is 1400kWh annually per kW installed, which is consistent with the experience of the Clean Energy Regulator and SA Power Networks.

The 'shape' of the solar insolation data varies month by month. It is illustrated in Figure 6, which shows the months of January, April, July and October.

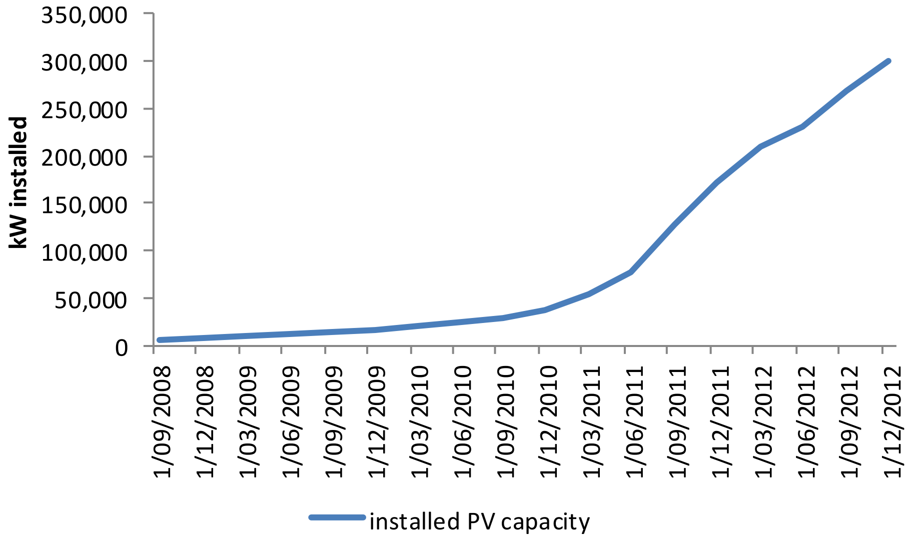
Figure 6 **Solar insolation profile**



Data source: Renewables SA

Figure 7 shows the installed capacity of PV systems.

Figure 7 **Installed solar PV capacity in South Australia (small customers)**



4.2.2 The relationship between small customer demand and South Australian regional (NEM) demand

The second step is to estimate the relationship between the two historical demand series developed in section 4.2.1. That relationship was estimated using multiple linear regression. A number of specifications were considered in the process. The specification that provided the best fit and most reasonable results was:

$$N_t = 863.42 - 428.8 * peak_t + (0.740 * peak_t - 0.938) * load_t + (0.000485 - 0.000257 * peak_t) * {load_t}^2 - 12.5 * Q2 + 44.5 * Q3 - 10.9 * Q4$$

Where: N *is the sum of South Australian NSLP load and estimated (gross) PV output*

Peak *is 1 from 7:00am until 11:00pm weekdays (excluding public holidays in all NEM states) and 0 otherwise*

Load *is the sum of South Australian regional reference load and estimated (gross) PV output*

Q2 *is 1 during the second quarter of the calendar year, that is, April, May and June and 0 otherwise*

Q3 *is 1 during the third quarter of the calendar year, July August and September and 0 otherwise*

Q4	*is 1 during the fourth quarter of the calendar year, October, November and December and 0 otherwise*
t	*is a half hourly time index*

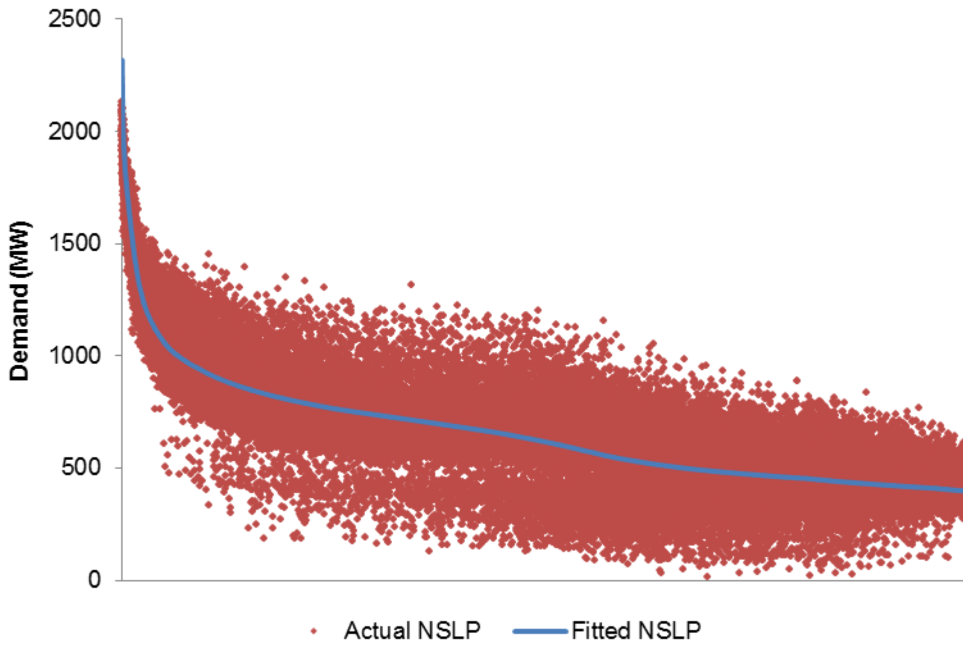
This model shows that the total load from customers on the NSLP in any given half hour can be estimated from the regional reference load and the characteristics of the period in question (i.e. whether it is a peak period the time of year).

All else being equal, the NSLP load exhibits a different relationship to the regional reference load during peak times, which is why the peak dummy is included in the regression on its own, and also interacted with the load and load squared terms. The NSLP is also typically lower relative to the regional reference load in the second and fourth quarters of a (calendar) year than in the first and third quarters.

This model accounts for approximately 70 per cent of the variability in NSLP load. All coefficients are statistically significant at well in excess of the 99 per cent confident level, as is the model itself.

The strong ability of the model to explain historic NSLP levels on the basis of historic NEM load and period dummies for peak periods and the calendar quarters is illustrated in Figure 8, which compares the actual historic NSLP values and the fitted values predicted by the model for those same periods.

Figure 8 **Historic NSLP comparison of fitted and actual**



Note: Fitted NSLP values sorted into descending order
Source: Actual NSLP data from AEMO; fitted values derived by ACIL Tasman

4.2.3 Projecting small customer demand for electricity

The nest step in the process of projecting the NSLP is to create a projection of small customer demand for electricity. That is, a projection of the sum of:

1. the NSLP and
2. the output of PV systems

We do this using the regression equation described in section 4.2.2 above and the load projection for the SA NEM region used in developing the *PowerMark* price projection for 2013-14 (plus information about peak periods and calendar quarters).

4.2.4 Estimating the NSLP

The three steps described above yield a projection of the hourly demand of small customers in South Australia (all of whom are charged using the NSLP). However, this is not the demand profile that determines the wholesale cost of electricity to retailers. Rather, that cost is determined by the NSLP *less* the total amount of electricity generated by PV systems.

To calculate this we subtract an estimate of the output of PV systems which is estimated using the process described in section 4.2.1 above based on a projection of PV capacity.

4.3 Projecting distribution loss factors

We have analysed historic distribution loss factors for the SA NEM region published by AEMO. As Table 4 shows, historically these have been approximately eight per cent. While there is some annual variation, we have assumed that this central level will not change over time.[32] Therefore, our estimates of the value of exported PV output are based on the assumption that distribution losses are 8.00 per cent.

Table 4 **Historic loss factors in South Australia**

	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13
Low voltage customer DLF	1.0799	1.079	1.074	1.0814	1.0765	1.0800
SA VTN MLF	1.0001	1.0009	1.0057	1.0003	1.003	0.9981
Combined loss factor (= DLF × MLF)	1.0800	1.0800	1.0801	1.0817	1.0797	1.0779
Implied losses	**8.00%**	**8.00%**	**8.01%**	**8.17%**	**7.97%**	**7.78%**

Note: DLF means distribution loss factor. MLF means marginal loss factor and applies to the transmission network. VTN means virtual transmission node and is an aggregated representation of most consumption MLFs in the SA NEM region.

Data source: AEMO

4.4 Projecting market and ancillary service fees

Market and ancillary services fees in the projection period are based on the most recent actual fees as per AEMO's budget, which is published in May each year. For projection periods longer than one year they would be escalated at 2.5 per cent in nominal terms.

32 Assuming that losses remain close to the historic range means that any errors introduced by this assumption will be minimal and within the error margin of the wholesale electricity price projection.

5 Timing issues

The Commission has also asked for advice regarding timing. In particular, whether the methodology used to estimate the fair value of exported PV output provides a reason to do so on a calendar or financial year basis or whether other 'years' would be possible.

Mechanically there is no particular reason why the fair value of exported PV output could not be estimated for any 'year' the Commission prefers.[33] The most substantial input to the process is the *PowerMark projection. PowerMark* produces hourly projections of the wholesale spot price of electricity. Those projections could be used to produce estimates of the fair value of exported PV output over any specified time frame. There is no particular reason why they would need to be estimated for a conventional period such as a calendar or financial year.

The accuracy of that estimate would be best if it was done soon after the inputs were estimated. Therefore, all else being equal we would recommend that the Commission align the estimation of the retailer payment to the availability of inputs. As discussed below, the key inputs are published by AEMO. The input that is likely to have the most substantial impact on the estimate of the fair value of exported PV output is AEMO's projection of electricity demand, which is published on approximately 1 July each year.

If the Commission wished to publish an estimate on or before 1 July each year to apply for a financial year, that estimate would necessarily be based on NEFR forecasts published approximately one year earlier. In our view this is likely to introduce error.

Possibly a more accurate approach would be to determine the retailer payment soon after the release of the NEFR. Time would need to be allowed for ACIL Tasman to incorporate the new NEFR projections into *PowerMark,* and for the Commission to consider advice and make a determination.

However, it may also be prudent for the Commission to align itself with other stakeholders in the market. In particular, the Commission may wish to make its projections comparable with forward contract market prices for wholesale electricity. This would suggest moving to align with financial quarters so the start date may shift to 1 October each year.

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[33] There would no doubt be practical implications for the retailers who make the payment. We understand that the Commission will discuss these issues with retailers separately.

Another approach would be to align with calendar years, as is done in Victoria. This would mean that the NEFR projections were not as old as they would be if a financial year basis was used as is done in Western Australia, New South Wales and Queensland.

A more detailed discussion of the timing of inputs to each of the four steps in our methodology is below. The steps themselves are:

1. project the wholesale spot price of electricity
2. weight that projection by the projected NSLP
3. adjust the weighted projection for:
   a) distribution losses
   b) market and ancillary service fees.

The key input for the first step is AEMO's expected growth in demand for electricity, both maximum demand and energy sales. We understand that AEMO intends to publish these in the NEFR on approximately 1 July each year, with forecasts on a financial year basis.

ACIL Tasman typically updates *PowerMark* to reflect the new NEFR assumptions when they are published, though it may be approximately four weeks after the publication of the NEFR before updated projections were available.

There are also numerous other inputs to *PowerMark*, which ACIL Tasman updates on an ongoing basis.

The next input is the projected NSLP. This could be projected at any time using the parameters described in section 4.2. Those parameters were estimated based on three years data and would not necessarily need to be refreshed with more recent data (that is, the relationship between the NEM load and NSLP load is not likely to change substantially).

The inputs to this process are the NSLP and the (actual) NEM load for South Australia. AEMO publishes the NSLP on a weekly basis approximately three months in arrears and NEM load data daily. Therefore, if the Commission preferred to update the regression parameters this could be done at any time.

Similarly, it could be used to produce a projection of the NSLP for any desired time period.

The third and fourth inputs are fees and loss factors. Market fees apply on a financial year basis and are set by AEMO in its budget in approximately late May each year. Therefore, the most accurate way to incorporate market fees into our estimate of the fair value of exported PV output would be to prepare that estimate on a financial year basis.

However, assuming that there is no dramatic change in either AEMO's roles and functions (which drives the total cost of market fees) or in the total quantity of electricity demanded (which drives the per MWh price), market fees should not change dramatically from year to year. Further, market fees have a very small impact on the fair value of exported PV output (approximately 0.04 c/kWh, or half of one per cent of the total value).

Ancillary service fees are more variable than market fees and are difficult to predict. However, they are also very small relative to other wholesale price of electricity and, therefore, our estimate of the fair value of exported PV output.

Distribution loss factors are set in advance by AEMO on a financial year basis. However, unlike market and ancillary services charges they are published in September, after the financial year has commenced. As with Market fees, distribution losses represent a small portion of the fair value of exported PV output. They are not likely to change substantially over time.

Therefore, while it might be most accurate from the perspective of market and ancillary service fees and distribution loss factors to estimate the fair value of exported PV output on a financial year basis, we see this as a relatively minor factor.[34] If the Commission preferred to determine the retailer payment for a different year, we would recommend assuming that these values do not change from one financial year to the next.[35]

[34] The improvement in accuracy of the overall projection that would arise from using these on a financial basis would be outweighed by the deterioration in the wholesale price projection due to the 'age' of the demand growth assumptions.

[35] This would be adequate when determining the retailer payment for a single year. If the estimate was to be made for a longer period an alternative approach may be needed.

Appendix A Impacts of exported PV output that do not provide value to retailers

This Appendix provides a discussion of the impacts that exported PV output has, or may have, that do not provide value to the PV customer's 'own' retailer. They may provide benefit to retailers collectively or to other parties. In either case, they do not form part of our estimate of the fair and reasonable value to a retailer of exported PV output.

The factors considered are:

- The impact of hedge contracts is discussed in section A.1
- changes in retailers contract position in section A.2
- retailer operating costs are discussed in section A.3
- deferred network augmentation costs in section A.4
- 'green schemes' in section A.5
- the impact on the wholesale price of electricity in section A.6
- the impact on network loss factors in section A.7

A.1 Why hedge contracts do not affect the value to retailers

Wholesale electricity for South Australian customers is sold into and bought through the NEM wholesale pool. Electricity retailers pay the NEM spot price for all electricity they purchase in any given half-hour period.

However, given the potential variability and volatility in the wholesale spot price, electricity retailers also typically enter into a variety of financial contracts to manage the risks they face in purchasing electricity from the wholesale NEM pool. While the wholesale price can range from -$1,000 per MWh to $12,900 per MWh,[36] retailers generally sell this electricity to small customers at a fixed price. That price varies from retailer to retailer and covers both wholesale electricity, network access and other costs.

This raises the question whether the existence of these financial contracts affects the value of exported PV output to electricity retailers, that is, whether the NSLP-weighted wholesale spot price of electricity estimated in section is

[36] This was the market price cap at the time of writing. It is indexed to inflation so it will increase over time.

the appropriate measure of value to retailers, or whether it should be adjusted to take contractual positions into account.

A typical portfolio of contracts is designed to hedge against price risk. However, it does not limit retailers' exposure to volume risk. Therefore for a fixed contractual position[37] any variation in quantity of the electricity they purchase results in a cost (for an increase in consumption) or a saving (for a decrease in consumption) equal to the wholesale spot price. Where a retailer purchases less electricity from the wholesale market due to exported PV output it receives from its customers, it benefits by avoiding the wholesale spot price for each unit of reduced consumption.

It follows from this analysis that the fair and reasonable value of exported PV output to a retailer from avoided NSLP purchases will equal the NSLP-weighted spot price, irrespective of the retailer's fixed contractual position.

A.2 Avoided contracting and risk management costs

In section A.1 we established that, for a fixed contractual position, electricity retailers are exposed to the wholesale spot price of electricity when their customers change their consumption. Therefore, we concluded that the NSLP-weighted wholesale spot price of electricity was the relevant basis for estimating the fair and reasonable value to a retailer of exported PV output, irrespective of contractual positions.

In reaching that conclusion we assumed that contract positions would remain fixed. If retailers adjust their contractual positions because they receive increased exported PV output from their customers, they would also change their contracting and risk management costs.

Similarly to the discussion in section 3.1, the effect of exported PV output on the contractual positions of electricity retailers must be viewed by reference to the settlement process and the NSLP.

In South Australia settlement is based on profiling and there is no time of use metering for small customers. Therefore, an electricity retailer supplying a small customer does not need to hedge itself against price risk associated with the customer's *actual* usage but the price risk associated with purchasing *its share of the NSLP*.

[37] The question of whether exported PV output would lead a retailer to change its contract position is discussed in section A.2.

This is an important distinction. When a retailer acquires a new small customer from another retailer, its exposure to the wholesale spot price is 'filtered' through the NSLP. The incremental effect of a customer transfer on the 'acquiring' retailer is that its share of the purchase obligations derived from the NSLP increases. The increase is affected by the amount of electricity the transferring customer uses, but not by the time of use.

If the transferring customer has an existing PV system there is no price effect (that is, the shape of the NSLP will not change). Therefore, any impact on the retailer must be through the volume effect.

In this case, the acquiring retailer's exposure to the peak wholesale spot price will increase in proportion to its share of consumption in the NSLP. Therefore its optimal contracting position per unit of energy purchased through the NSLP will be unchanged. The same is true of the retailer from which the customer has been acquired.

Similarly, if a customer installs a new PV system this will cause all retailers (not just the retailer that supplies that customer) to face a different exposure to the peak wholesale spot price to change through the price effect. This in turn may affect their optimal contracting position but, critically, this will impact all retailers equally and so no single retailer will benefit from it.

In neither case will any *individual* retailer receive a benefit from avoided contracting and risk management costs that is not also enjoyed by its competitors. Accordingly, any saving that does exist would be competed away and passed through to consumers.[38]

[38] This conclusion holds with the current metering arrangements, in particular the lack of interval meters. If metering arrangements were to change this issue would need to be considered in more detail.

A.3 Retailer operating costs

There are other costs to being an electricity retailer than just the cost of electricity bought for customers. Retailer operating costs are the costs associated with operating the 'machinery' of being a retailer. In its most recent (2010) retail price determination, the Commission included the following items in its assessment of retailer operating costs:[39,40]

- customer service
- sales and marketing
- revenue collection
- management and support (including corporate functions)

Retailer operating costs depend more on the number of customers a retailer supplies rather than the quantity of electricity it supplies them. This is reflected in the Commission's approach to estimating retailer operating costs in setting regulated retail prices, which it does on a 'per customer' basis.

There is a possibility that customers with PV systems are more costly for retailers to service than other customers. However, whether or not this is the case, the additional cost is not related to the quantity of exported PV output. Therefore adjusting the estimated fair and reasonable value of exported PV output to account for these costs would allocate them incorrectly, even if the costs themselves do exist.

Therefore, we make no adjustment to the estimated value of PV output to account for differences in retailer operating costs.

A.4 Network costs

The potential value that embedded generation, renewable or otherwise, can provide to electricity networks has been widely discussed.

Simply put, electricity networks are built to transfer electricity from the generator to the user. Networks have finite capacity and, in some places, they are capacity constrained, meaning that when demand is high the network comes close to, or even exceeds, its capacity. When demand exceeds capacity

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[39] The Commission also considers the cost of meeting obligations under the Residential Energy Efficiency Scheme. These are dealt with separately in our analysis and discussed in section A.5.

[40] Essential Services Commission of South Australia, "2010 Review of Retail Electricity Standing Contract Price Path, Final Inquiry Report and Final Price Determination", December 2010. p A-85, available at http://www.escosa.sa.gov.au/projects/143/2010-electricity-standing-contract-price-path-inquiry.aspx, accessed 27 September 2011.

the network is unable to supply all of the electricity that is required and augmentation of the network is required to avoid outages.

When electricity is generated close to the load, it need not be transferred through as many components of the network. Therefore, an alternative to increasing the capacity of the network used to supply a capacity constrained area may be to 'embed' a generator in that area to bypass some components of the network that might otherwise require upgrading.

The cost of providing network infrastructure is approximately half of a typical retail bill. It has grown at a faster rate than other components of the electricity bill in recent years. Therefore any cost-effective means of deferring network investment is worthy of consideration.

Network costs for electricity consumers in the NEM states are determined through a regulatory process undertaken by the Australian Energy Regulator. This process results in a price control formula that governs prices for a five year period. The network charges that arise from that formula are paid by retailers and recovered from small (and other) customers. Small customers pay for these charges on their retail bill, typically through a flat daily charge and an amount calculated on a per kWh basis.

Two issues are presented.

First, from the retailer's perspective, network charges are simply 'passed through' to network businesses. Aside from some risk management implications, the retailer is unaffected by changes in the total cost of network provision. Therefore retailers do not capture any benefit (or incur any cost) in relation to network charges by purchasing exported PV output.

The same is not true for PV customers. When they use PV output in the home, they avoid the network element of their retail bill because it is paid on a per kWh basis. Therefore, the total amount that PV customers pay for access to the network is reduced. All else being equal, this means that non-PV customers pay more for the network than PV customers. On the face of it, this may seem reasonable because PV customers also reduce their use of the network. They buy less electricity and thus less of it is transferred to them on the network.

Further, for PV systems to defer network augmentation they would need to be installed in areas where the network is prone to being constrained and export electricity when those constraints bind. This implies that any payment related to network augmentation would be subject to the location, and usage, of the PV system in question and could not be averaged across all customers in any meaningful way.

In addition, South Australia's electricity network was designed for uni-directional flows. There is some evidence to suggest that PV systems actually increase network costs due to the bi-directional electricity flows associated with them.

Our view is that the exported value of PV output should not be altered to account for changes in network costs.[41]

A.5 Green schemes

'Green scheme' costs are the costs to retailers of complying with the various schemes that are in place in Australia to reduce the environmental impact of energy use, generally by encouraging energy efficiency or renewable generation.

The schemes that apply in respect of electricity consumers in South Australia are:

- the Large-scale Renewable Energy Target (LRET), a Commonwealth Government scheme that requires electricity retailers to support the development of large-scale renewable energy sources by purchasing certificates created by the generators in proportion to their electricity acquisitions on behalf of consumers
- the Small-scale Renewable Energy Scheme (SRES), a Commonwealth Government scheme that requires electricity retailers to support the development of small-scale renewable energy sources such as PV and solar water heaters by purchasing certificates created by these sources in proportion to their electricity acquisitions on behalf of consumers
- the Residential Energy Efficiency Scheme (REES), a South Australian Government scheme that requires electricity retailers to support uptake of energy efficiency opportunities by households by purchasing certificates that represent pre-specified energy efficiency actions, in proportion to their electricity sales.

In each case, electricity retailers are directly liable for the cost of these schemes in proportion to their wholesale electricity purchases or electricity sales. The corollary of this is that, if their share of electricity purchases or sales increase, compliance costs with these schemes increase in direct proportion.

In the case of the LRET and SRES, where liabilities are in proportion to electricity acquisitions on behalf of customers, exported PV output is treated as an acquisition by the retailer from the owner of the system and included in the total volume of that retailer's 'relevant acquisitions'. This reconciliation is

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41 As discussed in section 3.2, this is not to say that it should not be adjusted to account for avoided losses.

similar to the settlement process by which the value of avoided wholesale purchase costs accrues to financial retailers.

ACIL Tasman has confirmed with the regulator of these schemes, the Clean Energy Regulator (the CER, formerly the Office of the Renewable Energy Regulator), that the overall effect of CER's treatment of relevant acquisitions is such that using exported PV output in place of wholesale electricity acquisitions does not reduce a retailer's liability for these schemes.

Therefore, avoided LRET and SRES compliance costs are not a source of financial benefit to electricity retailers from exported PV output.

The point of liability for the REES is slightly different to the LRET and SRES, being based on final sales. However, the final outcome is the same: under the REES, exported PV output is ultimately consumed at another premises and therefore liable under the REES.

Accordingly, exported PV output does not offer a financial benefit to electricity retailers through a reduction in compliance costs associated with the LRET and SRES, and is not relevant to the Commission's estimation of the retailer payment.

A.6 Reduced wholesale electricity prices

The 'price effect' discussed in section 3.1.4 considers the change in the NSLP-weighted price paid by all retailers for wholesale energy purchases made on behalf of small customers that results from an increasing level of PV generation. This occurs because PV generation tends to occur at higher priced times during the day and so reduces the NSLP-weighted price (by increasing its weighting towards overnight prices periods). This effect occurs even if NEM region prices are themselves unchanged by the advent of increased PV generation.

This section considers the case where increasing PV generation is sufficient to change NEM pricing outcomes, and whether this change would provide value to electricity retailers.

The output of PV systems in place in South Australia at the moment will undoubtedly have reduced the wholesale spot price of electricity below what it would have been had those systems not been in place. This is reflected in recent prices and therefore in projections based on demand growth from present levels.

However, changes in the wholesale spot price of electricity are not necessarily beneficial to retailers. As all retailers pay the NSLP-weighted spot price for purchases made on behalf of small customers, reductions in the spot price will pass through to all retailers equally. As with the price effect, our assessment is that these changes will accrue to customers through the competitive market.[42]

A.7 Reduced network loss factors

In general, increasing levels of PV generation (including exports) across the South Australian network result in a greater volume of electricity being generated close to the point of consumption. In turn, this would tend to result in a general reduction in the level of losses in the network as it increasingly displaces remotely generated wholesale electricity.

In practice, this would cause the loss factors AEMO uses in settling the market to change.

This effect may have already occurred to some extent, and may well occur to a greater extent in future as PV installations continue.

However, similar to the discussion in section A.6 above, any such reduction in the loss factors in the electricity network will not provide a financial benefit to electricity retailers.

All retailers purchase wholesale electricity at the RRN of the relevant NEM region and on-sell it, after losses, to consumers. The losses attributable to each retailer are calculated using the same loss factors so all retailers face the same cost associated with losses. Therefore, all retailers face the same change in this cost whenever loss factors change.

It follows that any reduction (increase) in losses would tend to reduce (increase) electricity costs in total for consumers. It would not be captured by electricity retailers.

42 In fact, the installations could even occur in other NEM regions as the physical interconnection of NEM regions allows for price competition between them.

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