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Article

Household Solar Photovoltaics: Supplier of Marginal Abatement, or Primary Source of Low-Emission Power?

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Abstract: With declining system costs and assuming a short energy payback period, photovoltaics (PV) should, at face value, be able to make a meaningful contribution to reducing the emission intensity of Australia's electricity system. However, solar is an intermittent power source and households remain completely dependent on a "less than green" electricity grid for reliable electricity. Further, much of the energy impact of PV occurs outside of the conventional boundaries of PV life-cycle analyses (LCA). This paper examines these competing observations and explores the broader impacts of a high penetration of household PV using Melbourne, Victoria as a reference. It concludes that in a grid dominated by unsequestered coal and gas, PV provides a legitimate source of emission abatement at high, but declining costs, with the potential for network and peak demand support. It may be technically possible to integrate a high penetration of PV, but the economic and energy cost of accommodating high-penetration PV erodes much of the benefits. Future developments in PV, storage, and integration technologies may allow PV to take on a greater long term role, but in the time horizon usually discussed in climate policy, a large-scale expansion of household PV may hinder rather than assist deep cuts to the emission intensity of Australia's electricity system.

Keywords: solar PV; peak demand; greenhouse emissions; embodied energy; EROI

Abbreviations

AUD: Australian dollar; g CO_2-e: grams of carbon dioxide-equivalent; GJ: energy, 10^9 joules; GW: power, 10^9 watts (joules per second); GWh: energy, 10^9 watt-hours; kVA: apparent power, 10^3 volt-amperes; kW: power, 10^3 watts; kWh: energy, 10^3 watt-hours equal to 3.6 megajoules; MW:

power, 10^6 watts; MWh: energy, 10^6 watt-hours; PJ: energy, 10^{15} joules; TWh: energy, 10^{12} watt-hours; USD: US dollar; Wh: watt-hour, unit of energy equal to 3,600 joules.

1. Introduction

The Garnaut Climate Change Review reports that the emission intensity of Australia's electricity system would need to decline from its current 850 g CO_2-e/kWh to between 110 and 200 g CO_2-e/kWh under Australia's contribution to a 450 or 550 ppm CO_2 scenario respectively by 2045 [1]. Given that Victoria's electricity emission intensity is the highest in the country at 1,210 g CO_2-e/kWh due to a reliance on brown coal [2], Victoria would need to decrease its emission intensity by 80 to 90% to meet national emission goals in just over 30 years. Assuming declining costs, at face value household PV should be able to make a useful contribution to decreasing the emission intensity of Australia's electricity supply. However, homes that install grid-connected solar remain completely dependent on a "less than green" electricity grid, and PV does not meaningfully displace network generation or distribution capacity [3,4]. Further, the manufacture and installation of PV incurs an energy debt through its embodied energy [5], and few analyses include the full upstream costs of PV [6,7], or attempt to capture a pro-rata allocation of the downstream costs of distribution and ancillary services.

It seems that much of the discussion around PV is focused on exploring theoretical potential, assuming *ipso facto* that a high penetration of PV is desirable. Most high-penetration PV analyses invariably conclude that a radical transformation in grid configuration will be required, including a substantial shift from baseload to "flexible generation" with increased ancillary services and storage (see for example Sayeef *et al*. [8], and Denholm and Margolis [9]). Yet there is a dearth of rigorous analysis demonstrating that such a transformation offers the most promising pathway to a near-zero emission electricity supply within the time frame discussed in climate policy.

In a review of 23 high-penetration renewables studies (for example, Delucchi & Jacobson [10], WWF [11], Wright and Hearps [12]), most of which included PV with an installed capacity ranging from around 20 to 45% by 2050, Reedman [13] reported that they rarely consider the routine technical, integration and cost implications beyond exploring the theoretical capacity to deliver sufficient energy. Although some researchers, including Mackay [14], Moriarty and Honnery [15], and Smil [16] have drawn attention to the practical limits of techno-renewables, perhaps more fundamentally, as Trainer [17] has noted, there is reluctance in the academic and technical literature to critically reviewing such studies, with environmental NGOs and green parties subsequently uncritically accepting the conclusion that world energy demand can be more-or-less affordably met with mostly solar, wind and biofuels given the appropriate policy settings and incentives.

This paper explores the technical challenges of PV integration in the Australian National Electricity Market (NEM), with a focus on Melbourne, and concludes that it may be possible to integrate a high penetration of PV, but that the economic and energy cost of accommodating high-penetration PV erodes much of the benefits. Further, PV is not suited to taking on a primary network role or delivering sufficient surplus energy when a fuller account of embodied energy is included.

The conclusion is that low penetration PV provides a legitimate source of emission abatement with high but declining abatement costs, assuming the grid continues to be dominated by unsequestered coal and gas. However, in the time horizon usually discussed in climate policy, a rapid expansion of PV may accelerate a path-dependence towards a sub-optimal generation mix, undermine the economic case for low-emission baseload, and hinder efforts to delivering the deep emission cuts recommended towards the middle of the century.

2. Household Reliance on a "Less than Green" Electricity Grid

2.1. Solar Energy Available

Although the earth catches only a tiny fraction of the total solar output, the quantity of energy is enormous; the rate of global fossil fuel consumption is about 0.006% of the solar energy intercepted [18]. Assuming a PV efficiency of 15%, with an average daily insolation of at least 5 kWh/m^2, a square with 31 km sides completely filled with PV would collect annual energy equivalent to Australia's current annual electricity requirements (assume 261 TWh). In an urban context, PV has the benefit of being highly suited to being accommodated within the built environment with low maintenance requirements.

However, the defining characteristics of solar are that it is an intermittent power source, driven by strong daily and annual seasonal cycles, with a very low power density relative to conventional generation technologies [16]. Further, the cost of accumulating sufficient annual energy represents only a fraction of the economic and energy cost of building and maintaining a modern electricity system (see Section 7); more than just about any other product, the generation and delivery of electricity are tasks in managing real-time demand and power flows.

2.2. Modeled Household Demand and Solar PV

To further explore this, fixed-axis rooftop PV was modeled with half-hourly solar data for Melbourne for 2010, using modeled Victorian household half-hourly demand profile depicted in Deloitte [19], with an annualized average of 15.5 kWh/day. Direct and diffuse solar data at half-hourly intervals from the Bureau of Meteorology, along with solar panel azimuth and tilt, were used with the NOAA solar calculation spreadsheet [20] to obtain solar output for Melbourne. Approximately 1% of the solar data samples were missing; these were estimated by interpolating from adjacent data points.

The annual energy break-even point for the assumed demand profile of 15.5 kWh/day is a solar capacity of 4.4 kW. Note that for the purposes of this section, the solar capacity is the actual maximum output rather than the manufacturers' "rated peak output". Referring to Table 1, it is evident that households remain completely dependent on the grid; for example a home that generates twice the annual energy it consumes will still be importing power from the grid for 63% of annual hours.

2.3. Temporal Profile of Available Solar Energy

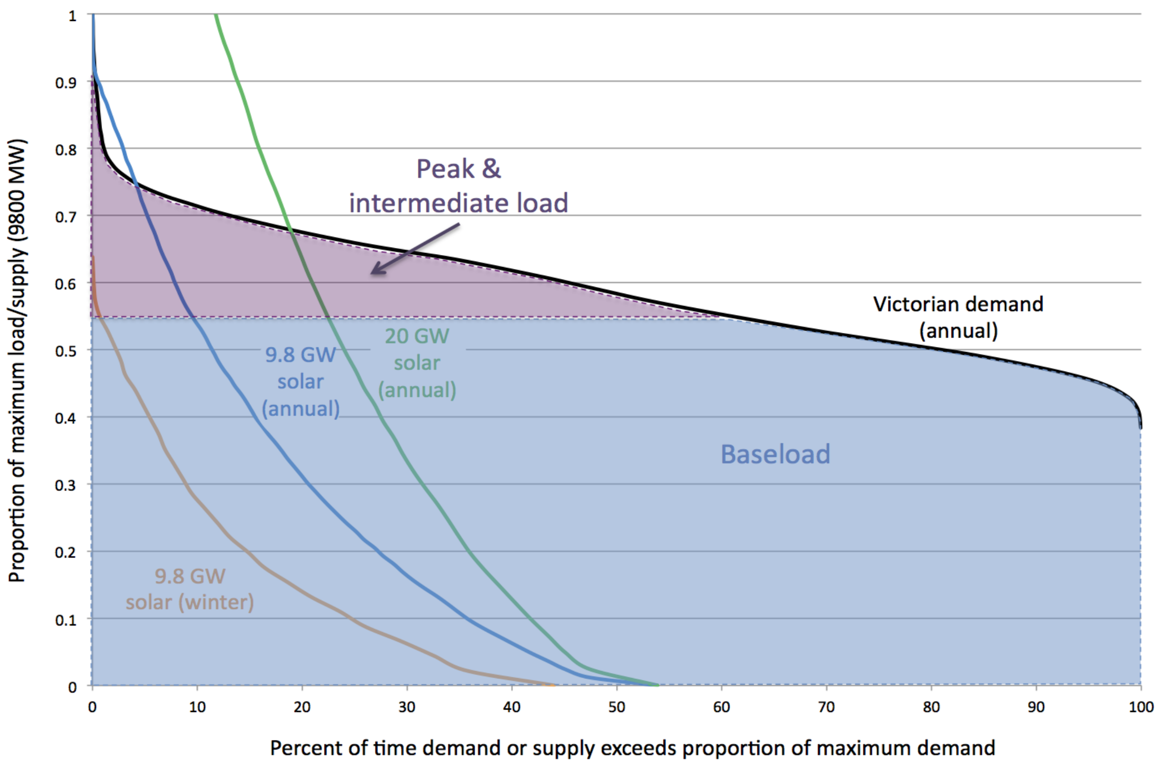
The reason for this is that most of the energy is generated in a proportionally small amount of time. In Melbourne in 2010 with a fixed axis north-facing panel, 80% of the total solar energy was produced in 22% of annual hours.

The temporal profile of supply and demand can be depicted with the annualized load duration chart (see Figure 1), which is plotted as the proportion of time (x-axis) in which the demand (or supply) exceeds a proportion of maximum annual demand (y-axis). Half-hourly demand data from the network operator (AEMO) was input into a spreadsheet to obtain the load duration curve for Victoria for 2010, with the maximum demand at 9,800 MW. The familiar S-shape curve is nearly universal for large electricity systems, in which demand resides between approximately 45 and 75% for most annual hours, but where there are relatively few hours at the extremities of demand. In particular, the sharp upward turn on the left part of the graph represents the relatively few hours in which demand spikes. In Victoria, peak demand has been growing at a greater rate than annual energy demand, mostly in response to increasing penetration of air conditioning [3]. Note that the area under the graph represents the annual energy demand.

Table 1. Proportion of annual energy consumption that is imported from the grid *versus* solar capacity, for a home with a typical demand profile using solar data in Melbourne for 2010. Assume north-facing azimuth with average tilt of 25°, corresponding to average Australian roof pitch.

Solar capacity (kW)	Proportion of annual energy consumption that is imported from the grid (%)	Proportion of annual hours that power is being imported (%)
0.0	100	100
1.0	79	92
2.0	70	80
4.4	63	70
8.8	58	63

Figure 1. Load duration chart for Victorian demand 2010, and modeled supply duration chart for solar for Melbourne 2010 at 9,800 MW, 20,000 MW, and the winter months June and July with 9,800 MW. Baseload area based on 75% of the total area under the annual load duration chart.



The supply duration curves for various solar capacities have been superimposed onto the graph, where the area under the curve represents the modeled annual energy supply. There are three key observations: firstly, the low capacity factor forces the solar curves towards the left of the graph, resulting in a comparatively low proportion of annual energy; secondly, at a high solar capacity, the solar supply will exceed system demand at times, requiring energy storage to capture the excess power or otherwise requiring the excess power to be curtailed or spilled [9]; and thirdly, the curve for winter highlights the ineffectiveness of solar in winter.

2.4. Quantity of Household PV Practically Available in Victoria

To gauge the relative scale of plausible household PV capacity in Victoria; there are currently around 2.1 million households in Victoria, with around 80% being free-standing houses or semi-detached terrace or townhouses [21]. AEMO [22] estimated the average maximum PV capacity per household based on work done by the City of Port Philip, which conducted a detailed analysis of roof orientation and tilt, shading, geometry, and solar insolation, and provided a first-order estimate of 3.5 kW. Assuming an uptake rate at saturation of 75% of homes [22], this equates to a total solar capacity of 4,400 MW. This paper is focused on fixed axis household PV that is embedded within the low-voltage network, but of course PV could also be installed on factories and warehouses, or on-ground installations.

2.5. Contribution to System Energy with Increased System Flexibility

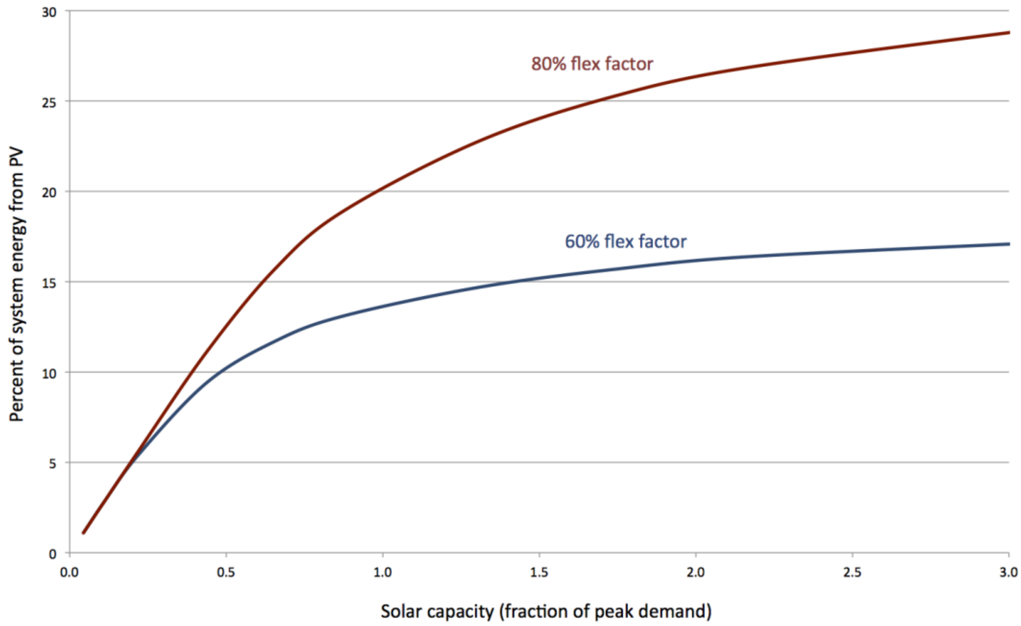
The "flexibility factor" is defined as the generation capacity as a proportion of peak demand that can be readily adjusted to accommodate rapid fluctuations in PV output without significant penalties [9,23]. There is a trade-off between the capacity of baseload plant, which can provide lowest cost generation, *versus* the capacity of flexible plant, which can readily adjust supply to meet varying demand and meet contingency events. The flexibility factor is around 60% for typical thermal dominated electricity systems. In the event that the combined supply from PV and baseload exceeds demand, some of the generated power will be required to be curtailed, spilled, or bypassed to storage. With PV at below around 5% of annual system energy, conventional systems possess sufficient flexibility to accommodate PV, but as PV penetration increases, the usable energy becomes limited by system flexibility.

Figure 2 depicts the proportion of usable energy from PV for Melbourne for 2010 for two different flexibility factors. With a flexibility factor of around 60%, the Victorian network would begin requiring curtailment of PV from around 5% of system energy, corresponding to 1,900 MW of PV. At 4,400 MW of PV, 16% of generated PV energy would be curtailed, rising to 46% at 9,800 MW of PV (*i.e.*, nearly half of the energy is unusable without storage). However, if most of the baseload was replaced with flexible plant, raising the flexibility factor to around 80%, the curtailment falls to 20%.

Denholm and Margolis [9] conducted simulations on the Texas grid (ERCOT) and found that with a 100% flexible grid, and with PV capacity set at *three times* the maximum peak load, a 50% system penetration could be possible. But this is really just a theoretical exercise; the modeling ignores reserve margins, and large networks will continue to possess some baseload, and other renewable generation, especially wind, is dispatched on a "must-take" basis, reducing the practical flexibility factor. Indeed Denholm and Margolis report a limit of 10 to 20% with practical limits of flexibility. Myers *et al.* [23,24]

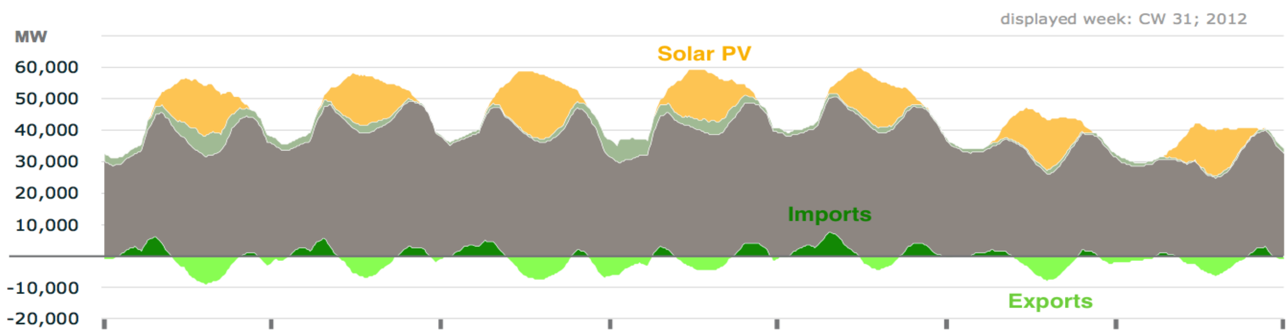
formed similar conclusions in Wisconsin, with a theoretical annual penetration of 40% with no baseload and PV capacity set to four times annual peak demand, reducing to 15 to 20% with a 60% flexible grid.

Figure 2. Usable system energy from photovoltaics (PV) in Victoria for conventional flexibility factor of 60% and 80% for Melbourne in 2010.



These estimates represent theoretical limits, but other integration issues that will be discussed further in Section 6 will constrain penetration, while storage and interconnection with other grids will increase it. For example, during the European summer, Germany's electricity exports are highly correlated with PV output (see Figure 3), with imports providing flexibility on PV down-ramps. It is informative that the German EEG2012 requires PV inverters to have curtailment capability [25]. In 2012, PV made up 5.8% of Germany's electricity production with 32,400 MW of PV (as at 31 December 2012) [26].

Figure 3. Germany electricity production, week 31, 2012. Source [26].



In Australia, the three largest cities, and around 90% of the NEM demand lies within 9 degrees of longitude (equivalent to a separation of local solar noon of 36 minutes), severely limiting the potential for interconnections to balance solar's diurnal cycle across NEM regions.

3. Network Support with PV

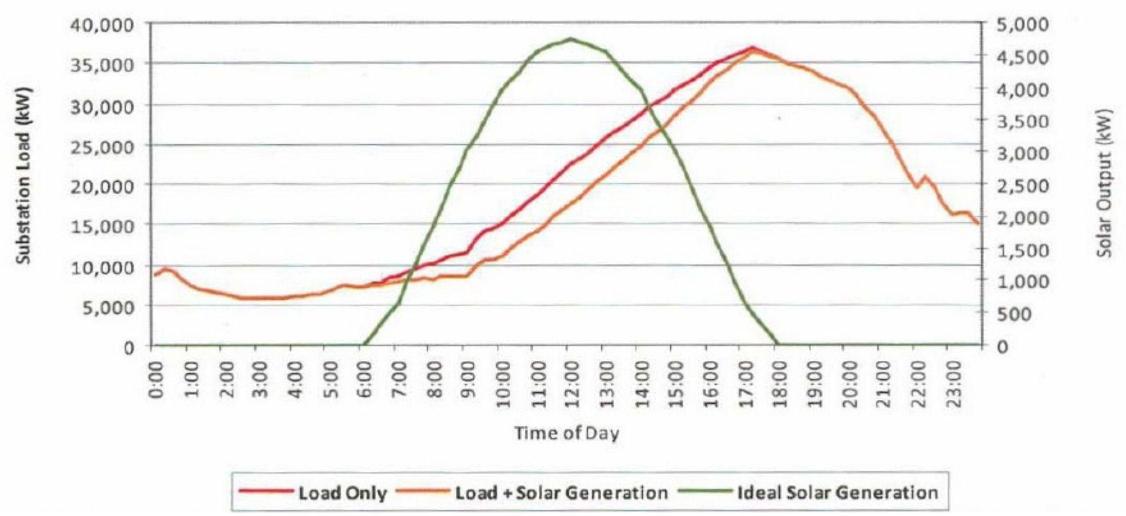
3.1. Reliance on the Distribution Network

Since solar output follows a diurnal cycle, output is biased towards day-time peak-pricing and will never occur during night-time off-peak periods; the annual solar-weighted return for Victoria in 2010 was 56.2 AUD/MWh (5.6 cents per kWh), while the overall Victorian demand-weighted wholesale price was 39.9 AUD/MWh (3.9 cents per kWh) (author's calculations). Since household solar is embedded within the low-voltage distribution network, the resulting loading on the distribution and transmission networks will be lower during periods of high solar insolation.

However the key driver of network augmentation costs are a relatively few critical peak demand events, which in Australia are increasingly driven by domestic air-conditioning on very hot summer days [4]. Although solar broadly correlates with air conditioning load during the middle of the day, the correlation generally weakens during the late afternoon, and completely dissipates by the early evening when domestic air conditioning load typically remains strong as householders arrive home from work. In contrast, commercial air conditioning loads reduce at the end of the work day, and provide a generally better match with solar [27].

Figure 4 depicts the demand on a hot day for a substation servicing 6850 mostly domestic customers in NSW. Although solar output was strong, solar had dropped to zero by the time that demand peaked at 18:00, resulting in a negligible reduction in daily peak demand. Although figure 4 is a particularly stark example of a residential substation, it nonetheless highlights the observation that the solar curve is always centred on local solar noon, while demand usually peaks in the afternoon or early evening.

Figure 4. Glenmore Park Zone Substation NSW, with 6850 customers. Solar simulation for 12 Jan 2010, assume 50% have solar @ 1.5 kW. Source: Endeavour Energy [28].



The orientation of panels towards the west will shift the solar curve around one and a half hours later in the day and improve the usefulness of PV output, but provide less annual output. Although some days would benefit, modeling shows that the net effect is mixed (see Table 2). Under current regulatory arrangements, incentives are structured to encourage maximum annual energy production rather than provide network support ([3], p. 14). This paper is focused on household PV, but PV farms with one or two-axis tracking will flatten and expand the output profile. The downside to PV farms however is that the valuable network support that is potentially captured by embedded generation is lost.

Table 2. Victorian peak demand in MW without solar, and with hypothetical 2,000 MW of installed solar in Melbourne in 2010, with demand reduction as a proportion of solar capacity, with all panels facing north or west. Based on half-hourly Victorian demand and Melbourne solar insolation.

	Peak gross demand	Peak net demand [north/west]	Relative reduction (%) [north/west]
11 Jan	9858	9168/8948	35/45
8 Feb	9465	8596/8281	43/59
9 Feb	9463	9025/9025	22/22
12 Jan	9301	7607/7784	85/76
10 Feb	9100	9051/9051	2/2
2 Feb	8966	8356/8300	31/33
3 Feb	8920	8671/8671	12/12
11 Feb	8604	8457/8457	7/7
26 Feb	8405	7934/7909	24/25
19 Feb	8236	7605/7505	32/37

Table 2 tabulates the 10 highest demand days in Victoria in 2010, with net demand assuming 2,000 MW of either all north-facing solar, or all west-facing. The relative reduction in peak demand due to solar is highly dependent on the respective daily demand and solar profiles. For example, there was an excellent correlation on 12 January, with a demand reduction of 85% of solar capacity, but in contrast there were several days, such as 10 February, when the solar capacity provided virtually no benefit at all. Myers *et al*. [23] report similar results in a study in Wisconsin.

Although the solar generation may provide some minor localized benefits to the network, such as reduced transformer heating or short term transformer upgrade deferral [29], PV does not provide guaranteed supply during critical peak demand events. Therefore, it does not lead to a material reduction in distribution or network costs [3,4,30]. Indeed, the very fact that PV units are able to export power into the grid and earn a feed-in tariff implies that PV systems make use of the low-voltage distribution network. Further, PV consumers still make use of the billing and customer services provided by retailers, hence these are not avoided costs [31].

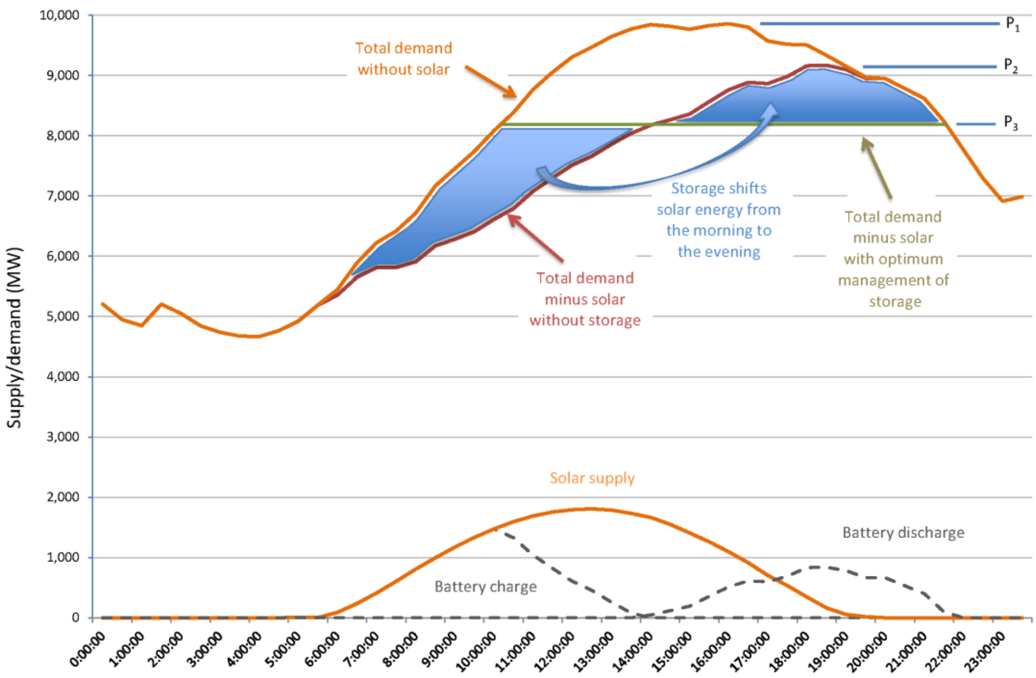
3.2. Battery Storage to Improve PV Capacity Credit

It is generally acknowledged that solar will require built-in storage if solar penetration is to increase markedly [8,32,33]. With a moderate amount of storage (up to 4 hours at full capacity), PV can provide a potentially important time-shifting or network support role, and reduce the quantity of spilled energy at a high penetration of PV [34]. Under the current regulatory system, PV is dispatched ahead of baseload; therefore, an excess of on-line power may result in "de-commit" auctions when generators compete to stay on-line to avoid shutting down or spilling energy [35]. Figure 5 describes the hypothetical role of a theoretical 2,000 MW solar with storage for the highest demand day in Victoria for 2010. The top part of the graph describes three demand curves.

(1). The orange curve is the actual Victorian demand for the day, with daily peak P_1.
(2). The red curve describes the net Victorian demand with 2,000 MW of Melbourne-based solar *without* storage, with resulting daily peak P_2.
(3). The green curve/line describes the net Victorian demand with solar, and *with* storage assuming the storage is operated with perfect hindsight, with resulting daily peak P_3.

The most obvious consequence of storage is that the peak load P_1 is reduced from 9,800 MW to a P_3 of 8,100 MW, thereby reducing the resulting peak load by 85% of solar capacity, whereas without storage, the daily peak P_2 was reduced by 35% of solar capacity. The storage required in the above example equates to around 5,300 MWh, or equivalent to 2.7 MWh per MW of installed solar capacity (*i.e.*, 2.7 hours of storage or 5.4 kWh per kW of solar assuming 50% depth-of-discharge).

Figure 5. Hypothetical role of battery storage in reducing peak demand, based on highest demand day in 2010 on 11 Jan using idealized storage management with perfect hindsight with 80% storage cycle efficiency.



Closer observation of the graph reveals the idealized operation of storage described as 4 discrete steps as follows:

(1). All of the solar is diverted to storage until 10:00 in the morning.
(2). From 10:00 until 13:30, an increasing proportion of solar is fed directly into the grid with a decreasing proportion diverted to storage.
(3). From 13:30 in the early afternoon to 19:00 in the early evening, all of the solar is delivered directly to the grid, with support from the battery storage.
(4). From 19:00 to 22:00, there is no solar generation, but the battery continues to discharge.

This example is an idealized example of time-shifting with perfect hindsight. In practice, the real-time storage management would be optimized to maximize wholesale market price returns through arbitraging or otherwise the provision of ancillary services including ramp rate or voltage support [36].

3.3. Household PV with Storage to Improve Network Utilization

The cost of supplying an additional 1 kW of power to serve air conditioning load on hot days has been costed in one scenario at $2,000 in distribution, $1,200 in transmission, and $800 in generation ([3], p. 316), although the cost for individual scenarios is highly dependent on the spare capacity within each element of the system. Depending on battery cost, and the costs for the specific network augmentation, the cost of storage may be competitive in a peak demand mitigation role (see [36]).

From a Distribution Network Service Provider's (DNSP) perspective, faced with a choice between the upgrade of a durable passive device, such as a distribution transformer with a 35 year life, or the installation of an active storage system with a shorter life and with less operating experience, a rational DNSP would usually choose the more robust option unless a strong economic case could be argued. Unlike greenhouse mitigation and carbon pricing which comprises a trade-off between emission intensity and carbon costs, network augmentation is essentially a trade-off between initial capital costs *versus* lifetime costs [37].

In any event, as regulated monopolies, Australian DNSPs are able to pass through the costs regardless. Under current regulatory arrangements, it makes no sense for households to install batteries since they cannot capture the potential avoided network costs, nor access the wholesale spot market to potentially profit through arbitrage or provide ancillary services. Hence different distribution regulatory arrangements or incentives would need to be implemented before storage will be regularly included in grid-connected household PV.

3.4. Vehicle to Grid Storage (V2G)

This brief overview has only considered distributed, rather than large-scale storage, since local storage with batteries provides valuable distribution network support, is highly suited to the rapid ramping of PV output, and is readily available for charge and discharge cycles. In the future, other distributed storage options may emerge, such as vehicle-to-grid (V2G) [38].

At face value, electric vehicles (EV) would seem to have a natural synergy with baseload, which could provide low cost and predictable year-round off-peak power for charging when most vehicles are parked at home, whilst underpinning the load factor for baseload generators in the event of the electrification of the Australian motor car fleet (see chapter 9 [39]). Similarly, in regions that have excess wind power at night, the capability of effectively using excess power to charge vehicles may improve the value of wind energy (see Lund and Kempton [40]).

The problem with PV-based V2G is that the available supply will be inversely related to the preferred charging regime (*i.e.*, there will be no PV power available for night time charging when the grid has spare capacity, but during the three or four hours centered on solar noon, few motorists will want to "fill their tank" at the peak daytime tariff). Further, as Trainer [17,41] notes, EV batteries are expensive and their longevity is cycle-limited, so vehicle manufacturers will want to optimise their batteries for maximum driving range at lowest cost in order to produce a marketable vehicle, leaving limited spare capacity available for general grid storage. While V2G will offer a valuable niche role such as network support during critical peak demand events, the sort of integrated role envisaged by Delucchi & Jacobson [10], in which a considerable proportion of system energy is cycled through EV batteries on a daily basis, is probably vastly overstated (see [17] and [42]).

3.5. Network Support Summary

Summarizing, any network peak demand mitigation potential of PV and/or storage needs to be considered alongside other peak demand strategies, such as demand management, time-of-use-pricing [43], load shifting, targeted energy efficiency where it applies to peak loads [44,45], a market shift from refrigerated to evaporative cooling [46], and other strategies, most of which have demonstrated lower costs than PV. Further, storage as it relates to PV can only be practically considered within a daily reference rather than seasonal since storage capacity exceeding several days or weeks is not likely to be feasible for the foreseeable future [34].

4. Assessing the Value of PV for Greenhouse Abatement

4.1. Review of Australian Abatement Cost Estimates

There have been a number of estimates of the PV emission abatement cost in Australia, with varying assumptions and methodology. The main areas of difference are the amount of abatement per unit of electricity, appropriate lifetime, and whether we are discussing the private or social cost. The differences can in part be explained by the observation that we are attempting to estimate notional greenhouse abatement on the margins relative to our best guess of the counter-factual. The complexity of investment decisions, the bidding process within the NEM, and the interaction between wind and PV intermittency further complicates estimates of the counter-factual. In some cases, cost-effective abatement may not be the primary objective of PV policies that target research and development or learning-by-doing [47], although most of the benefit of the strong sales growth in PV in Australia has accrued to foreign manufacturers with little development in high value-added Australian manufacturing [48]; an estimated two-thirds of industry value was expended on imports in 2011 (see Table 15 [49]).

The Australian Productivity Commission [50] calculated an "implicit abatement subsidy" of \$432 to \$1,043 tonne/CO_2-e in 2011 for Australia. The implicit subsidy is an attempt to capture all government subsidies within a single factor that could be compared with an explicit carbon price for the purposes of international comparisons.

Macintosh and Wilkinson [48] calculated a figure of \$225 to \$260 tonne/CO_2-e for 2009 (AUD 2009) for Victoria with a 30 year life based on the method used by Oliver and Jackson [51]. The abatement cost is calculated as the generation cost difference between PV and marginal baseline cost, divided by the difference between the baseline emission factor and the full life-cycle emission factor for PV. Using this methodology, Victoria has the lowest abatement cost of all Australian states since it has moderate solar insolation and high baseline emission intensity based on brown coal. Macintosh and Wilkinson used Sherwani's [52] LCA emission factor for PV of 50 g CO_2-e/kWh, and the standard emission factors for each year for Victoria, projected into the future, from the DCCEE (which was 1,220 g CO_2-e/kWh in 2009 [53]).

But Lenzen (table 6.48 [54]) derives a range of 53 to 217 g CO_2-e/kWh for PV LCA using "very conservative" boundaries with a "base case" of 106 g CO_2-e/kWh. Outhred [35] notes that the diurnal supply profile of PV will tend to displace gas fired intermediate and peak load generation, and since Victoria's brown coal generators have historically had the lowest marginal cost in the NEM, individual units are only occasionally dispatched below full capacity [55] (Even with a modeled carbon price of AUD2010 \$55 per tonne CO_2-e, the Victorian brown coal generators, including Hazelwood, Loy Yang and Yallourn have amongst the lowest short run marginal cost, see table 31 [56]). The two largest gas-fired generators in Victoria, Mortlake and Newport, have emission intensities slightly less than half the Victorian baseline at 620 and 590 g CO_2-e/kWh respectively [56]. Hence, using these different factors results in a convergence of emissions abated from 1,170 to around 500 g CO_2-e/kWh, essentially more than doubling Macintosh and Wilkinson's estimated abatement cost.

In contrast, the Australian PV Association (APVA) [57] use the *retail* cost (*i.e.*, the private consumer cost) of the displaced generation, ignore the PV embodied energy, but also assume that PV displaces at the baseline emissions factor. The resulting abatement cost is somewhat lower at around \$90 tonne/CO_2-e (AUD 2011), with Victoria projected to reach zero abatement cost around 2015. While the use of the retail cost might be justifiable from an individual householder's perspective, it cannot be compared with the social cost, since the retail tariff includes the transmission, distribution, and retail cost, none of which are meaningfully displaced by the use of solar PV (for a more detailed analysis of the weakness of focusing on the retail tariff, see [4]).

4.2. Abatement Cost Calculation Methodology

Rather than trying to establish a decisive figure, the approach of this paper is to construct a chart for a range of avoided abatement intensities, solar insolations, solar costs and lifetimes to capture some of the key sensitivities. The methodology adopted is to assume that solar essentially "buys abatement" but does not displace conventional generation capacity, therefore displacing marginal costs (*i.e.*, reduces fuel use and variable operation and maintenance costs (VOM)). It will be assumed that gas costs \$4/GJ rising linearly to \$10/GJ in 2043 [56], consumed at 30% efficiency. Coal is costed at \$1/GJ through to 2043, at 28% efficiency. The major population centers in the NEM have annual PV outputs of between around 1,300 kWh/kW (Melbourne) and 1,550 kWh/kW (Brisbane), providing sensitivity to varying solar insolation.

Since the solar installation is a single up-front cost but fuel savings accrue over the full life, the savings will be discounted at 7% [47], along with the VOM of \$9/MWh for gas and \$1.40/MWh for coal [56]. It will be assumed that the inverter will be replaced at 10 year intervals at an installed cost of \$700 per kW, also discounted at 7%. Lenzen's [54] "base case" of 106 g CO_2-e/kWh will be assumed for PV LCA. Solar output degradation is assumed at a linear decline of 20% over 30 years [5].

4.3. Assumed Life of PV System

The calculation of abatement cost rests on the assumption that all systems will optimally perform for the duration of the assumed life (allowing for projected cell output degradation), however poor maintenance may contribute to higher idle time [6]. Over a potentially long PV life, the home may be sold more than once, output may be degraded due to dust, shading from growing trees (partial shading can significantly affect output), or some panels may deteriorate or bypass diodes malfunction at a higher rate than typically assumed. As a non-essential appliance, the maintenance may not be a household budget priority; for example the cost of a replacement inverter may exceed the loss of revenue over two or three years. On the other hand, many systems would be expected to last beyond 30 years, but relying on assumed abatement beyond the early 2040s in order to achieve a satisfactory abatement cost seems problematic.

The most thorough assessment in Australia of average lifetime has been through reviews of the Australian Renewable Energy Act (Electricity) 2000 [58]. The Australian Government applies a deeming formula for the creation of renewable energy certificates, which front-end loads the projected lifetime's energy generation. The deeming period was raised to 15 years in 2004 following a review of the Renewable Energy Act [59] because of confidence in the technology and extended warranties, although the Australian Climate Change Authority more recently noted that "there is little data against which to test the accuracy of the deeming calculations" [60]. For completeness, this paper will provide estimates for both 15 and 30 year assumed lifetimes.

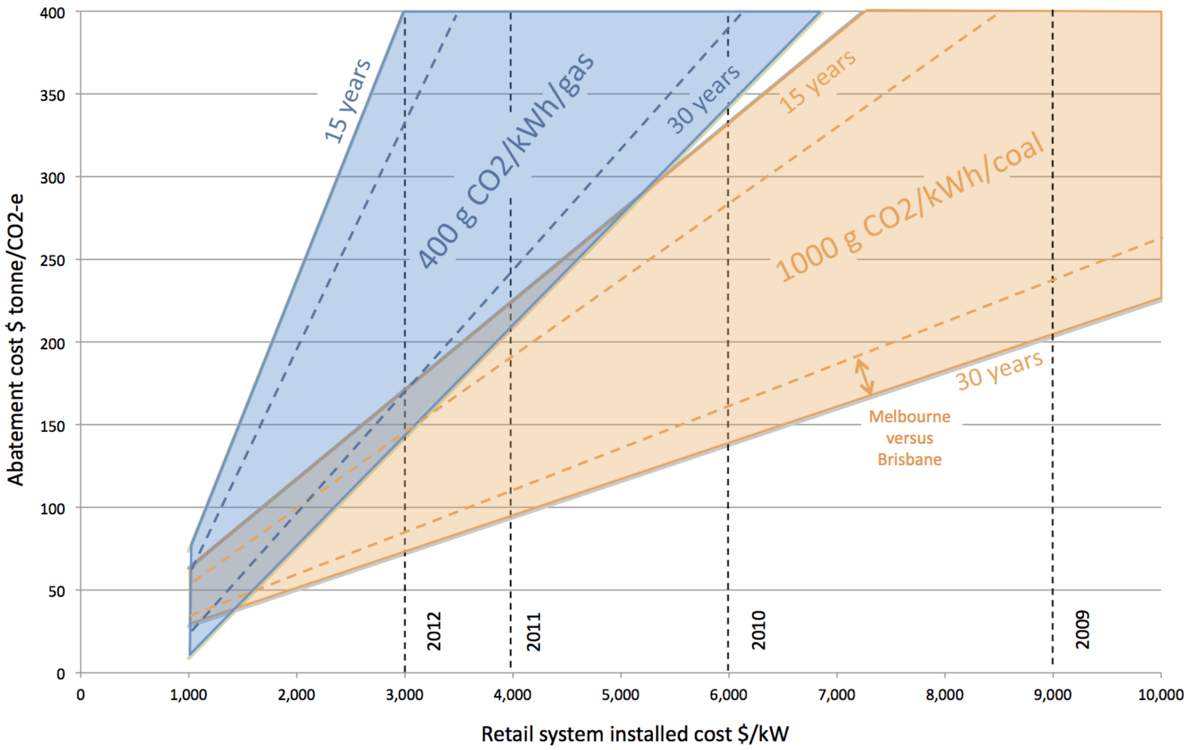
4.4. Loss of Abatement through Cycling and Sub-Optimal Operation of Thermal Generators

An additional factor that has not been included is the impact of increasing the aggregate variability (in addition to wind), which will lead to increased cycling of thermal generators and may force operation away from their optimum heat rate or result in off-loading of baseload generation. As a consequence, some of the emission gains of PV will be eroded by increased emission intensities of thermal generators. Where these issues have been examined in Australia, modeling suggests these effects will be minor at a moderate penetration of intermittent power since the grid is already configured for variability and state interconnectors allow moderation of variability (SKM MMA [61]). However, the SKM MMA report only modeled up to 500 MW of PV in Victoria, which would represent 1.3% of Victoria's electricity consumption in 2010. At increasing penetrations of intermittent generation, particular from around 5 to 10% of annual energy, these effects may become more pronounced and result in a material reduction in expected abatement [62].

4.5. Abatement Cost Estimate

As Figure 6 shows, the abatement cost is highly variable depending on the assumptions, and the significant price reductions in solar since 2009 has substantially decreased the cost. It is difficult to project future price declines due to the complex dynamics of the PV supply chain in recent years [63]. The recent major cost reductions have been mostly due to declining module costs, which have declined to 35%–40% of the installed cost [64]. For Melbourne, assuming a system installed cost of $3,000/kW for good quality branded components, and using *current* gas and coal costs, the abatement costs equates to $117 for abated gas at 600 g CO_2-e/kWh and $71 for abated coal at 1,200 g CO_2-e/kWh over 30 years, increasing to $256 and $143 respectively over 15 years.

Figure 6. Emission abatement chart, system installed cost *versus* abatement cost, for Melbourne at 1,300 kWh/annum and Brisbane at 1,550 kWh/annum, displaced generation gas ($4 to $10/GJ) at 400 g CO_2-e/kWh and coal ($1/GJ) at 1000 g CO_2-e/kWh, 15 and 30 year abatement life. Vertical dated lines represent the installed cost in Australia of solar for 2009–2012. Costs are AUD 2012.



There is a range of defensible assumptions leading to widely divergent costs, and a static snapshot of abatement does not provide an insight into the dynamic nature of abatement [65]. For example, if Victoria were to adopt the most efficient CCGT (combined-cycle gas turbine) currently deployed in Australia as a direct baseload replacement with an emission intensity below 400 g CO_2-e/kWh, the rationale for PV abatement is significantly diluted, even with further declines in PV cost. In the event of a longer-term shift to low-emission baseload, such as coal with carbon capture, nuclear, engineered-geothermal, or concentrated solar thermal with gas backup (hybrid CSP) [66], abatement of the electricity system *per se* would have little meaning.

4.6. PV in Relation to Other Abatement Opportunities

Summarizing, the use of PV as an abatement strategy needs to be considered alongside other mitigation measures, such as energy efficiency, fuel substitution, and other measures that may provide more abatement for a given cost. Even with declining module costs, PV is not likely to be among the cheapest ways to abate emissions for the foreseeable future (for example, see exhibit 5 [67]). However, PV remains very popular [68] and for various reasons Australian governments have found it very difficult to implement the lowest cost abatement options first [50]. Given the uncertainties and complexities of PV abatement, it provides a good case study in arguing for policy instruments that target abatement directly rather than picking favorites with highly uncertain outcomes [69].

5. Practical Constraints on Grid Integration

5.1. Redefining Baseload

There have traditionally been two overlapping ways to define baseload power. The first considers the *demand* profile, and is defined as the minimum power demand on the electricity network, usually the minimum overnight load. The second considers baseload in terms of *supply*, and is generally understood to mean low marginal cost generators that run continuously at utilization rates of greater than 70% such as coal or nuclear [70]. Traditionally, the intended role of baseload generation is to provide the bulk of the energy requirements at lowest cost, with higher marginal cost peak and intermediate load providing load following [71]. Baseload coal provides 75% of Australia's annual electricity supply [72], with a reserve-to-production ratio of 128 and 517 years for black and brown coal respectively, along with significant proven reserves of conventional and unconventional gas (see Table 2.2 [72]); therefore any prospective greenhouse emission abatement strategy needs to either replace or displace conventional baseload generation or otherwise sequester the resulting emissions.

However, the expansion of non-dispatchable renewable energy has forced a blurring of power systems terminology since intermittent technologies do not provide a clear role in providing reliable energy supply beyond emission abatement [73]. For example, Sovacool [74] argues that the concept of baseload is as much about the "social, political, and practical inertia of the traditional electricity generation system", citing the large penetration of wind in Denmark as evidence of the potential for intermittent generation to displace baseload. Indeed, Archer and Jacobson [75] suggest that a significant proportion of the capacity of interconnected wind farms can be used as baseload power. On the other hand Diesendorf [76] and Elliston *et al*. [77] argue that baseload can be thought of as a *system*, rather than an individual generator unit, suggesting that we require a "radical 21st century re-conception of an electricity supply-demand system".

Indeed, given the option of creating a brand new electricity supply model, there may well be alternative models that serve social, economic and environmental ends more effectively. But as O'Sullivan [78] argues, the social and economic burden of maintaining existing infrastructure with moderate growth is challenging enough. If we were to contemplate a complete refashioning of the electricity grid within the timeframe discussed in climate policy, the cost would be overwhelming.

5.2. Reduced Load Factor of Electricity Systems with PV

In these re-conceptions of baseload, the shift is away from lowest-cost electricity delivered by large, high-utilization units towards distributed, lower-utilization, and higher-cost electricity generation. Indeed, there is broad consensus that a shift to intermittent sources of electricity will require greater use of quicker response dispatchable generation, such as gas turbines as well as large-scale storage [8,79]. However a shift to lower capacity factor generation will necessarily lower the system load factor, which describes the ratio of average to peak power demand. A low load factor implies that a significant proportion of generation units are idle for most of the time with obvious consequences for costs, while a high load factor implies efficient use of plant. The PV capacity factor for the ten largest Australian cities in the NEM is between 15% and 18% [80], and since PV does not displace conventional generation capacity, an increase in PV penetration will *necessarily* reduce the overall load factor.

Table 3 depicts the load factor for the Australian NEM in comparison with a recent 100% renewable scenario based on wind, solar, hydro and biofuels by Elliston *et al*. [77] demonstrating the substantial lowering of load factor as a consequence of a shift from a large penetration of baseload to a mix of renewables and flexible plant.

Table 3. Load factor comparison for Australian National Electricity Market (NEM) in 2010 compared to a renewable scenario with 20% reserve margin added (see Lang [81]). Source: Elliston *et al*. [77].

	NEM	**Elliston *et al.***
Capacity without reserve [GW]		84.5
Reserve margin @ 20% [GW]		16.9
Capacity including reserve [GW]	43	101.4
Peak demand [GW]	33.6	33.6
Annual generation [TWh]	204.4	204.4
Calculated load factor [%]	54	23

5.3. Comparison of Reliability Measures for Conventional Versus PV

Conventional thermal generators can be off-line due to planned maintenance, which is typically scheduled around off-peak periods and low seasons, and unplanned outages. The average forced outage rate (FOR) in advanced countries is typically 4%–6% for conventional generation, with an equivalent availability factor (EAF) of around 90% (for example, see pg. 87 [82]). In Victoria, the Yallourn coal-fired generator for example, which was commissioned in 1973, had a FOR of 3.9% and an EAF of 89.5% in 2010 ([83], p. 19).

Since the failure risk profile of thermal generators is mostly uncorrelated, each additional generator adds to the aggregate reliability. The risk associated with “credible contingency events”, such as the sudden loss of a large generator unit, is addressed through setting appropriate reserve margins and ancillary services. In contrast, reserve margins would not work for a fleet of renewable generators since the generation profile tends to be highly correlated within a geographic region; adding PV installations within a region does not increase the probability that electricity will be generated on a cloudy winter day or at night time.

Instead, the intermittency of wind and solar is often discussed in terms of the statistical measures of loss of load probability (LOLP) and capacity credit, which provide a means to assess the marginal utility of intermittent plant within an established, highly reliable network. Since modern grids are already configured to accommodate variability and contingencies, low-penetration intermittency can be compared with normal demand-driven variability and accommodated accordingly. Indeed, the UKERC review of the literature on intermittency [84], focusing on wind in the UK, suggests that the consumer costs of variability at a low penetration of intermittent penetration can be quite low. However they also note that above 20% penetration, “more radical changes would be needed in order to accommodate renewables” ([84], p. vii).

While the use of statistical measures can provide useful insights at low PV grid penetration, they can also distract from the obvious; there is negligible PV output around 60% of annual hours and there are always going to be times when there is neither PV output nor meaningful wind within the Australian NEM (for example, see Figure 2 [77]).

5.4. Comparison of Cost for Conventional Versus PV

The most common metric for costing generation technologies is the levelised cost of electricity (LCOE), which represents the per-kWh cost of building and operating a generating plant over an assumed financial life and duty cycle [85]. In a recent review, Bazillian *et al.* [63] reports a current LCOE of between 16 and 32 cents per kWh (USD) for residential PV systems. EPRI [86] projects the Australian LCOE for a range of other low-emission technologies at between 8 and 21 cents per kWh for 2030 (AUD 2010, see [86], p. xxii). Hence, taking the raw LCOE costs and assuming ongoing cost reductions, PV would be expected to be competitive with other low emission technologies in the relevant timeframe for climate policy.

But as noted earlier, since PV does not directly displace generation capacity, it makes no sense to compare the LCOE of PV with fit-for-purpose dispatchable generation [85]; a more meaningful comparison is to compare the PV LCOE *versus* the variable operating and fuel cost of dispatchable generation. Before factoring in a carbon price (see Section 4), these typically comprise 10 to 25% of the overall LCOE of baseload generation, or around half of the cost of open-cycle gas (OCGT) (see Tables 10.3 to 10.13 [86]).

Another method would be to add sufficient storage and solar capacity to provide a PV system with an equivalent annual availability factor to conventional generation, which would allow a more direct comparison; however this typically increases PV system lifetime costs three to four-fold (see Section 7.5).

Summarizing, PV may be competitive with OCGT where the cost of gas is high, or in remote grids with high fuel costs, such as those with diesel generators [63]. But in the time horizon usually discussed in climate policy, there seems little prospect of PV being cost competitive with low-emission baseload, which, with the exception of CCGT, would have very low fuel costs in Australia.

5.5. Synchronous Generation, Inertia, and Grid Stability

In the early period of electricity generation, generators operated in electrically isolated networks since the parallel operation of generators was once a daunting engineering problem. But from the 1930s, the theory of parallel operation of generators in large networks was established [87], and all large electricity networks now operate with baseload generation providing the essential anchor role.

The Australian NEM, spanning five states and 4,500km, has around 260 registered generators [88], all of which when online, are synchronous machines spinning in near exact synchronization at close to 50 Hz across the network (the island state of Tasmania is connected via the non-synchronous Basslink DC link—see [89]), corresponding to a rotor speed of 3,000 RPM for 2-pole generators, or for example 500 RPM for large 12-pole hydro generators. Indeed, most global electricity is produced by synchronous generators driven by rotary turbines; in 2010, 96% of global electricity was generated by thermal or hydro plant [90], with nearly all being either steam, gas, or hydro turbines (see Smil [91]).

Synchronous generators have a vital role in maintaining network stability through the inertia in the rotating plant. When transients occur in the supply-load balance, some of the mechanical rotary inertia in the large turbines and generator rotors will be expended to dampen the instantaneous frequency change, giving generators time to respond to the changing balance without loss of stability. Through feedback, most of the generators utilize "droop" control to simultaneously change output to balance load and return frequency to nominal levels whilst maintaining balanced supply across generators [71].

Non-synchronous generators, including solar PV, are electronically synchronized to the grid and are required to disconnect if the network frequency or voltage exceeds pre-determined boundaries. Solar inverters rely on the presence of a stable grid, rather than themselves contributing to the stability, and do not contribute to system inertia or primary frequency regulation [92]. Indeed, the relative loss of inertia at high penetrations of renewables is a challenge to grid control systems [89,93], although as Sayeef *et al*. [8] note, there is no uniform view on the level of penetration of PV at which the additional ancillary services will become significant.

There are a number of technical remedies to the loss of inertia, including; running conventional generators in synchronous condenser mode (*i.e*., the generator is on-line and rotating but not driven by a prime mover), installing dedicated synchronous condensers, or the possible future development of "virtual inertia" storage systems to emulate physical inertia [94]. However, these incur a cost, and since the market has not traditionally required dedicated inertial support, there is no market signal under the current regulatory arrangements. Due to the low penetration of PV, this has not been an issue in Australia up to date, but in Tasmania the increasing penetration of wind in an otherwise small grid has forced the grid operator to formulate strategies to ensure network stability with the relative loss of inertia. For example, the Tasmanian Energy Department [95] has run hydro generators in synchronous condenser mode, noting the additional costs due to increased wear and cavitation, and more frequent starting and stopping.

5.6. Voltage Regulation

The nominal voltage in Australia had been 240 volts from 1926 but was changed to 230 volts in 2000 to align with international standards [96]. This requires that the voltage at the point of supply should differ from the nominal voltage of 230 volts by no more than +10%, −6% [97]. The electricity network is designed around unidirectional power flows; power flows from power stations to households via the transmission and distribution networks. At a substation network level, voltage regulation is achieved through transformer on-load tap changers (OLTC).

The system is designed to accommodate the predicable voltage gradient that occurs on residential feeders from substations. Normal variations in load along the low-voltage feeder cause voltage variations within prescribed limits; voltages will typically be higher at night time and lower during periods of high demand. Feeders are described as "weak" if there is high impedance on the line caused by low loads, leading to higher voltage variance in response to a change in load [98].

The problem with distributed PV generation is that the injection of power along the feeder raises the voltage gradient and can contribute to three-phase imbalance, and is particularly problematic when it occurs at the tail end of the feeder during periods of high solar insolation and low demand, such as during late mornings. Scattered cloud will tend to induce greater voltage variations, and depending on the normal variation, may contribute to forcing the voltage outside allowable limits or shutting down inverters [99]. At high localized penetration, PV output could force output backwards through the low-voltage distribution transformer and contribute to instability or over-voltage tripping at a substation level [100]. Australia has weaker grids and a different network structure to the US and Europe, and as such, network limits to solar PV may be reached sooner than in comparable countries [8].

Distributors are required to maintain minimum standards of performance and reliability, and will reject solar applications in instances where the injection of power may reduce reliability of supply; indeed, this has already been occurring in Australia [8]. There are a number of remedies to the altered voltage profile due to distributed PV, all with demonstrated effectiveness but with significant cost implications at large-scale;

(1). Converting households to a three-phase connection with the associated wiring, metering and switchgear, and installing a three-phase inverter. A typical home will cost $500 to $1,000 to upgrade to three phase plus additional inverter costs.
(2). The replacement of OLTC transformers with automatic tap-changing transformers, which require control systems and voltage monitoring within the network to alter the voltage in near real-time in response to prevailing load and supply voltage [101]. At, say $120 to $200 per kVA, the per-household cost of a transformer will be of the order of $500 to $1,000 plus control and monitoring cost.
(3). The commissioning of "smart grid" components to permit active control of solar inverters, storage devices, and loads in response to network operator directives [102].
(4). The use of bi-directional (four-quadrant) inverters to dynamically provide reactive power support and voltage regulation on feeders with high reactance (typically rural feeders) [103].
(5). Augmenting customer service and feeder mains to reduce the impedance seen by solar inverters.

The development of a "smart grid" is generally considered an essential component of high penetration PV [102], and is an evolutionary process that will evolve over many decades [104]. Victoria is the first Australian state to implement a "smart meter" program with time-of-use pricing, which should eventually lead to a moderation of a declining system load factor [43]. But the public controversy associated with the high cost of the program [105] is a reminder of the policy challenges of expensive large-scale network augmentations that do not provide an immediate and obvious environmental or consumer benefit.

Likewise for example, in the event of the forced scrapping of many of the operational OLTC transformers, in favour of more expensive automatic tap-changing models at distribution substations, along with the associated control and monitoring systems, would likely meet similar opposition, particularly given growing institutional opposition to "gold plating" of networks [3].

5.7. Solar Ramp Rate Driving a Need for Flexible Generation

The ramp rate of a generator represents the generator's ability to change its output, with baseload generally having a low ramp rate, gas-fired generation higher and hydro the fastest response, and can be either upwards or downwards (off-loading). The effect of increased intermittency is to increase the variance of the net-load and the system ramp rate. This is turn will require a shift towards greater reliance on load-following generation and less on baseload plant. Intermittent plant has the technical capacity to be installed with down-ramp capability; however without storage, they cannot have up-ramp capability.

An example of an event requiring rapid up-ramp is depicted in Figure 7, which occurred on 31 January 2010. A feature of Melbourne's summers is the passage of a cold front following a hot spell lasting from a single day to several days. These are often characterized by an abrupt wind change in wind direction, strong and gusty winds both before and after the change, and high temperatures and low relative humidities in the pre-frontal air [106]. The onset of cloud and an accompanying reduction in solar output can be rapid across the greater Melbourne region. The low-pressure trough (dashed line) moved eastwards across the region at approximately 75 km/h.

Figure 7. Satellite image and synoptic chart Australia 31 January 2010, 16:00 Melbourne time.

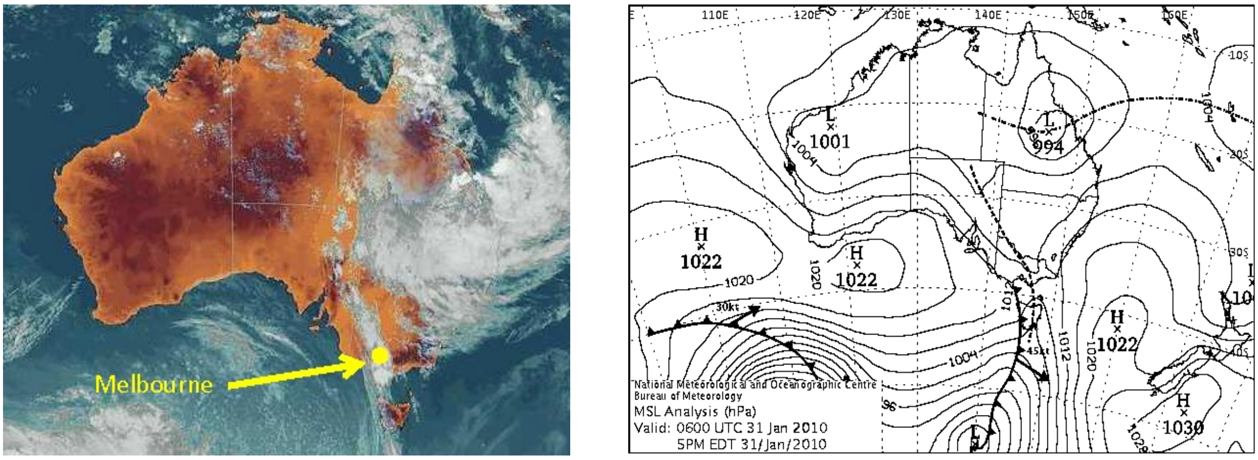
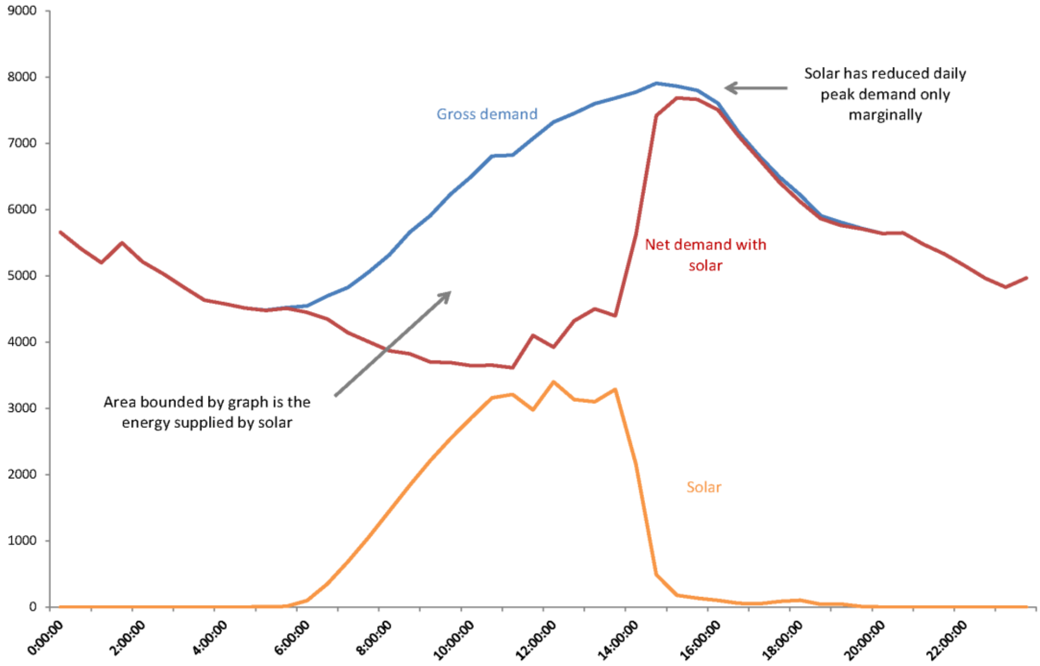


Figure 8 depicts the Victorian demand on that day, and the modeled solar output in Melbourne assuming 4,000 MW of PV capacity. The impact of the modeled PV is to moderate the resulting demand and reduce the load on the network up to 14:00. However, following the cool change, the solar output rapidly drops, requiring an additional 3,000 MW of rapidly dispatchable power. Also of interest on that day was that the three largest Victorian operating wind farms had near full output for most of the day, except for a lull lasting for about one hour when output dropped significantly with a delay of two hours after solar had dropped, before returning to high output, thereby further increasing net system variability.

The impact of geographic diversity will be to moderate short term ramping, although there is also evidence that there may be a limit on the effect of geographic dispersion. For example Curtright and Apt [107] report that site diversity over a 280 km range does not dampen PV fluctuations over a 20-minute to multi-hour time span. Interestingly, they contrast the time profile of the fluctuations of PV with wind, noting that wind can be often treated as negative load. But PV fluctuations are more demanding of the network requiring a greater need for matching firm power.

The issue in relation to ramping is that, in the example above, PV only generated 14% of the daily energy but the very high flexibility required of the system forces a path-dependence on less efficient open-cycle gas and storage, while penalising baseload. The ideal compliment to rapid ramps is hydropower, which has the highest up-ramp capability; however Australia has relative low topographic relief and limited water availability, limiting the practical expansion of hydro [108].

Figure 8. Total Victorian demand, modeled solar in Melbourne, and resulting demand for 31 January 2010.



6. High Penetration PV Forcing a Sub-Optimal Generation Mix

6.1. Risks and Uncertainties of Future Energy Technologies and Carbon Policies

A key challenge for policy makers is the uncertainty associated with future energy technologies, while for utilities and innovators, the political uncertainty over the coverage and price of carbon pricing mechanisms is a major barrier to low-emission investment in Australia [109]. Since carbon pricing is determined by government fiat, the credibility of commitment creates risks for low-emission innovations [110] and since electricity is an undifferentiated commodity product, there is no clear reward for first-movers [109]. Even in the event of a strong bi-partisan commitment to abatement, future governments may be motivated to subsequently lower the carbon price if competitive low-emission baseload technologies emerge. Since innovators are aware of this, the "announcement affect" of high future carbon prices will tend to be discounted [111,112].

6.2. Intermittent Generation Forcing a Sub-Optimal Generation Mix

In the meantime, policies have focused on current technologies that can deliver immediate marginal abatement, such as wind, PV and natural gas, but less attention has been given to the long-term strategic consequence of a shift to intermittent generation. The problem is that a shift in generation mix that is driven by factors such as the marginal abatement cost, renewable energy support policies, or a consumer preference for PV, may force a path-dependence and evolve into a sub-optimal generation mix into the future [65]. This may result in difficult and expensive choices in the future when deeper cuts are called for, but where path-dependence has locked in a generation mix that needs to be highly flexible to accommodate renewables [113].

6.3. Low-Emission Baseload Undermined by Intermittent Generation

Given that around 75% of Australia's electricity is currently generated by baseload generation with hundreds of years of easily accessible coal, it is essential that one of the candidate low-emission baseload technologies is targeted to deliver deep emission cuts [66]. But the problem is that the high capital cost of baseload generation relies on an expected high utilization to underpin its economic viability. Since PV is always dispatched ahead of baseload, it will tend to encourage investment in flexible generation [35], and thereby undermine the business case for low-emission baseload.

On the one hand, the primary driver of network and generation capacity is peak demand, but a falling annual energy demand will tend to force tariffs higher since the high capital and fixed operating costs will be spread over fewer units of output. If the higher tariffs lead consumers to invest further in household PV without a commensurate reduction in peak load, or efficiency, which may have only a marginal impact on peak load [44], a vicious cycle may ensue [114], resulting in upward ratcheting tariffs.

6.4. Solar PV Competing with Concentrated Solar Thermal and Wind

The two renewable energy technologies often taken as natural allies within a "suite of renewables" are concentrated solar thermal (CSP) and wind. But their insulation from the wholesale spot and bilateral contract market due to regulatory support obscures their natural rivalry within a competitive electricity market.

In Victoria in 2010, solar output during 13 non-contiguous summer hours contributed an astonishing 50% of the annual weighted revenue, where the spot price peaked at between \$1.72 and \$10.00 per kWh (usually \$0.03 to \$0.06). The impact of increased penetration of all forms of solar will be to depress the pool prices on sunny days, subsequently reducing revenue for all generators [115]. Indeed, Sandiford [116] reports a significant reduction in wholesale cost in Queensland and South Australia in 2011–12 in response to PV despite PV contributing only a modest share of system energy.

While the suppressing effect, often referred to as the "merit order" effect, may be favorable for retailers and consumers in the short run, the reduction in revenue for conventional generation may pose long term difficulties with maintenance of the network [115], and undermine the potential for other generators to maximize revenue streams during summer. CSP would be especially vulnerable since its output most closely aligns with that of PV, and more so if battery storage is included with PV.

In the case of wind, the respective stochastic and cyclic overlay of PV and wind does not offer any obvious mutually beneficial synergy. As such the more advanced market penetration of wind may result in a crowding out of PV as integration limits for intermittent generation become more tested over the next 10 to 20 years in Australia, potentially constraining the market potential for PV.

7. Embodied Energy

7.1. Embodied Energy of PV Systems

The embodied energy involved in producing the solar panels and ancillaries has been an active area of research over many years. Embodied energy for PV is usually measured as a payback time, i.e. the number of years it takes for the PV to generate the energy it took to produce the panel or system.

Another common measure, the EROI (energy return on investment) is a dimensionless term expressing the ratio of energy generated over its lifetime relative to the embodied energy, and was pioneered by ecologist Charles Hall and others in the 1970s [117]. The EROI, payback and related analyses are not a substitute for economic and other considerations, but provide a theoretical foundation for exploring the efficacy of specific technologies or projects [54].

There has traditionally been a significant divergence in the calculated embodied energy of PV. A large part of this was explained by differences in the allocation of energy due to the silicon purification and crystallization since solar cells used, to a large degree, off-spec material from the electronic industry, which requires a higher purity product [118,119]. Other factors include differing power mixes for the production processes, and process-specific emissions. In recent years, improvements in technology, in particular the production of highly refined silicon and the more efficient fabrication of the purified silicon into cells, has brought down the embodied energy significantly to the extent that some researchers now claim an energy payback time of less than 2 years [52]. However, other researchers suggest that half of the energy impacts occur in upstream activities outside of the boundaries of conventional PV LCA analyses (see Lenzen [54], Crawford [119], Trainer [7,120]), and a host of downstream ancillary and incidental energy costs are simply not considered in conventional PV LCA analyses (see Hall *et al*. [121], Hall and Prieto [6]).

It seems that much of the literature is concerned with defending a role for PV, assuming that PV is a non-essential add-on to an electricity meter rather than an integral component of the electricity network. If we are only concerned with the role of PV as a source of marginal abatement then it makes sense to ignore many of the costs associated with providing reliable electricity. But if we want to understand the ramifications of shifting to a high PV penetration scenario with PV as an integral component of the energy system, then we can no longer treat PV as merely a discretionary consumer purchase.

This section will take a similar, but simplified approach to a recent study by Prieto and Hall [6], which detailed the EROI for PV in Spain, to provide an assessment of additional downstream energy costs. The difference is that the vast majority of the installed PV power in Spain is in on-ground installations, a third of which are single or two-axis trackers.

7.2. Recent LCA Review

The following calculations will use a recent conventional LCA review by Raugei *et al*. [122], which provides an authoritative assessment for four types of cell using conventional boundaries. This paper will use two of these: mono-crystalline Si, which is widely deployed, and the less energy intensive, ribbon Si (see Table 4). Raugei *et al*. have used the average southern European insolation, which is comparable with the main population centers in the Australian NEM and a performance ratio of 0.75 [5], which derates the performance to allow for cell degradation and the difference between AC inverter output, and the module's rated DC performance.

Table 4. Calculation of energy return on energy investment (EROI) of PV EROI including BOS, from Table 1 Raugei *et al*. [122].

	Mono-c Si (rooftop)	**Ribbon Si (rooftop)**
Insolation [$kWh/(m^2 yr)$]	1,700	1,700
Performance ratio	0.75	0.75
Module efficiency	14%	13%
$E_{out,yr}$ [$kWh_{el}/(m^2 yr)$]	179	166
T [yr]	30	30
E_{out} [$kWh_{el}/(m^2)$]	5,355	4,973
E_{pp} [MJ_{PE}/m^2]	3,257	1,907
E_{pp} [kWh_{PE}/m^2]	905	530
Solar $EROI_{el} = E_{out}/E_{pp}$ (refer [122])	5.9	9.4

7.3. Primary Energy Equivalent

Conventional PV LCA analyses are expressed in terms of primary energy, but since fuels have differing quality and usefulness (for example, a joule of electricity is more useful than a joule of heat from coal), there is an argument that the EROI should include some provision to account for the varying usefulness [123]. Indeed, Raugei *et al*. argue that the $EROI_{el}$ of PV should be multiplied by ($1/\eta_{grid}$) to account for the fact that PV generates electricity directly. Taking a typical grid efficiency (η_{grid}) of around 0.31 thereby increases the "primary energy equivalent" ($EROI_{PE\text{-}eq}$) around three-fold.

While the conversion makes sense for some end-uses dependant on electricity such as lighting and electronic devices, it assumes perfect fuel substitutability and high conversion efficiency from electricity to other fuels [123], and also ignores the stochasticity of PV. And since electricity only accounts for 18% of global final consumption of energy [90], it is not obvious that applying a universal three-fold conversion factor is appropriate; indeed, the conversion can also work the other way [6].

For example, with the exception of electrified rail, liquid fuels, which constitute around a third of global primary energy, are far more valuable than electricity for transport applications. In the case of aircraft, shipping, heavy road, mining, and other heavy equipment, liquid fuels are a necessity for the foreseeable future [124], and studies typically report an electricity-to-wheels conversion efficiency of no better than 25% for electricity-to-hydrogen based transport (see [125,126]). On the other hand, EVs are more efficient than internal combustion engines, but these mostly represent consumer end-uses rather than being a key component of industrial production, and it is less obvious that PV is matched to EV charging regimes (see Section 3.3).

This paper will assume the standard convention of "primary energy", but acknowledges that a "primary energy equivalent" may be more relevant in some cases.

7.4. Reduction of EROI Due to Storage or Energy Spilling at High Penetration

At a low penetration of PV, all of the generated power will be fed into the grid. However, when the penetration exceeds 5 to 10%, increasingly larger amounts of PV energy will be required to be spilled or stored [9]. If the energy is stored, there will be a loss of efficiency, as well as the embodied energy in the batteries or other storage devices. For example, if 25% of the PV output is cycled through storage at 80% efficiency, the resulting energy loss equates to 5%.

Table 5 assumes 4 hours storage (see Denholm and Hand [34]), with 50% maximum depth-of-discharge with lead-acid batteries, which have the lowest embodied energy for commonly available batteries, and are highly recyclable. Although there continues to be intensive research into a host of storage devices, the most popular storage device for household solar continues to be the lead-acid battery [128]. The construction of the modern lead-acid battery can be dated to Camille Fauré's process in 1881 for coating the lead plates, which opened up the industrial scale production of the battery [129]. The high specific weight of the battery, being a critical weakness for electric vehicles, is not a problem in stationary applications. The longevity of the lead-acid battery provides a reality-check on the limits of technological innovation in energy conversion and storage (for example, Eisler's [130] 50-year historical account of the hydrogen fuel cell provides an antidote to the notion that a revolution in storage is "just around the corner").

Table 5. Calculation of embodied energy of batteries per square meter of solar.

	Mono-c Si (rooftop)	**Ribbon Si (rooftop)**
Assumed power of solar [kw_{max}/m^2]	0.14	0.13
Assumed battery depth-of-discharge [%]	50	50
Hours of capacity at full power [hours] (refer [34])	4	4
Storage capacity [Wh]	1120	1040
Sets of batteries over 30 years @ 7.5 yr life	4	4
Lead-acid (recycled) embodied energy [MJ/Wh] (refer pg. 21 [127])	0.87	0.87
E_{batt} [MJ/m^2]	3898	3619
E_{batt} [kWh/m^2]	1108	1005

EPRI [36] note that Li-ion batteries offer the most significant cost reduction potential in response to the scale up of electric vehicle production. Han and Han [131] report a recent EV wholesale battery cost of USD$300 to $500/kWh with an "ultimate goal" of $100/kWh, compared to the Australian wholesale cost for deep-cycle lead-acid batteries of AUD$180 to $250/kWh or a retail cost of AUD$250 to $300/kWh (the AUD and USD have been close to parity for some time). Other prospective battery technologies that have the potential for significant price reductions include the advanced lead-acid, Zn/Br flow batteries and emerging Zn/air and Fe/Cr [36].

7.5. Embodied Energy with an Off-Grid System

Using the assumptions above, it is possible to estimate the EROI for the limit condition of an off-grid system. Indeed, off-grid solar PV is frequently used in rural Australia in contexts where the cost of connecting to the nearest feeder is sufficiently high to justify the substantial capital outlay of an off-grid solar installation.

Non-critical stand-alone systems are commonly designed with 95% availability (equivalent to 5% loss-of-load) as a compromise between cost and utility [128] (a backup generator will be used to fill-in during extended overcast periods in winter). This provides comparable availability to conventional generation and a useful insight into the limit condition of a very high penetration of PV with PV providing a quasi-baseload role.

Half-hourly solar data for Melbourne, along with half-hourly demand data from Deloitte [19] was used in a spreadsheet model with VBA macros to model the system with storage. Deloitte's demand data provides for an average 15.5 kWh demand per day, but the magnitude of the daily demand does not alter the final EROI result. The model has been calculated as the solar/battery combination in which there were 438 hours (5% of annual hours) below 50% of battery capacity. The least cost option used 11.1 kW of solar capacity and 63 kWh of battery capacity assuming 50% depth of discharge (the most common depth of discharge for lead-acid deep cycle batteries), equivalent to about 2 days of storage. Using this data, the EROI can be calculated as 1.3 (see Table 6).

The lifetime discounted cost of the system is estimated at $80,317 with a LCOE of 47 cents/kWh (assume solar $2,500/kW, batteries $250/kWh with 7.5 year life, 5 kW off-grid charger/inverter $1,000/kW with 15 year life, 3.5% discount rate).

Table 6. Calculation of EROI for off-grid solar system over 30 years. Excludes generator and other ancillaries.

Daily energy used [kWh]	**15.5**
Solar capacity [kW]	11.1
Battery capacity [kWh]	63
E_{batt} [MJ] @ 4 sets over 30 yrs	219,240
Solar area [m^2]	79
E_{pp} [MJ_{PE}/m^2]	3,257
E_{solar} = solar area x E_{pp} [MJ]	258,234
$E_{system} = E_{pp} + E_{batt}$	477,474
E_{used} @ 15.5 kWh/day over 30 yrs [MJ]	611,010
System $EROI_{el} = E_{used}/(E_{solar} + E_{batt})$	1.3

7.6. Embodied Energy of the Distribution Network and Retailing

Since PV is a distributed energy source, it is generally assumed that the power is consumed locally and therefore analyses exclude the broader costs of delivering the energy and the costs associated with adapting the network to accommodate PV. Indeed, the IEA-PV guidelines for PV LCA imply that the boundary should end at the inverter output (see Section 3.2.3 [5]). Yet, modern electricity systems are integrated systems that require an entire chain to deliver a precisely regulated product when and where it is needed. No single generator is responsible for distribution, yet it is clear that distribution has a significant cost and therefore an embodied energy content that must be accounted for if the system is to achieve an energy surplus. If we are concerned with whether PV can provide a primary energy role, then a pro-rata allocation of the embodied energy must be attributed to PV.

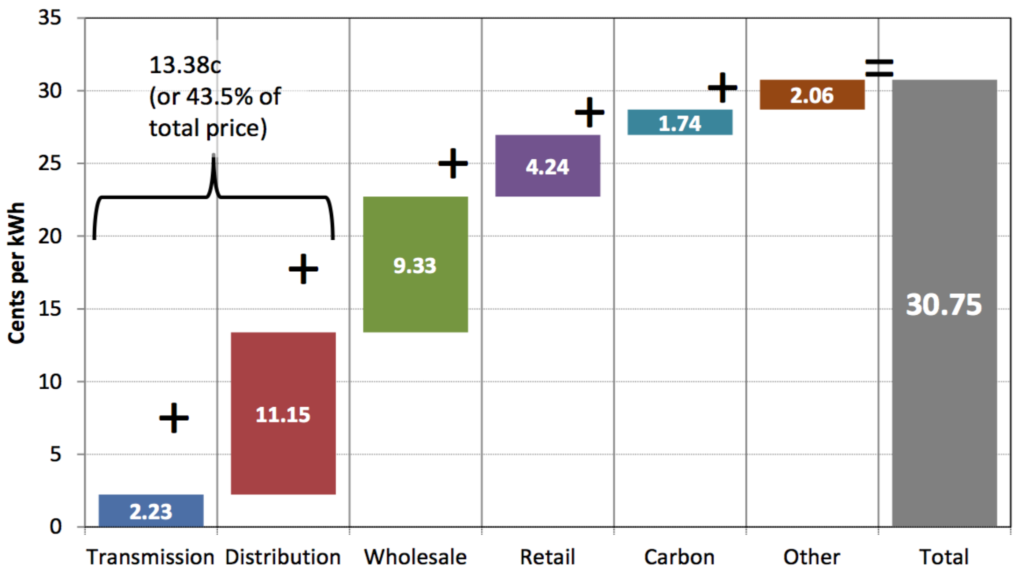
For example, in an assessment of the EROI of oil, Hall *et al*. [121] estimate that an EROI of 10:1 at the wellhead translates to an "extended EROI" of 3:1 at the petrol pump when the energy costs of refining, refinery losses, distribution, and supporting infrastructure are taken into account. It is assumed that the energy costs of electricity distribution would be much lower since the electricity taken from the generator is already a high quality power source without requiring chemical and physical transformation, but nonetheless, transmission and distribution makes up around half of the value of retail electricity. Since PV is embedded within the low-voltage network, it will not be subject to conventional transmission and distribution losses of 5% (Table 9 [134]).

Table 7 provides an overview of the industry value of the Australian electricity supply industry. The respective shares of electricity supply are broadly consistent with the retail cost (see Figure 9). The ABS [135] provides the energy intensity (GJ per $m of value added) for a range of industries, but does not provide a breakdown of the energy intensity of distribution. The average for all industries was 2,500 GJ/$m, and the water and waste utilities had an intensity of 1,970 GJ/$m, which provides a reference point for a utility. Taking an industry value added of $9.5B for distribution and assuming an energy intensity of $2,000 GJ/$m gives 19.0 PJ, which is 2.0% of the total electricity sold. This represents the direct energy inputs, but does not include most of the embodied energy within the physical infrastructure (concrete poles, wires, transformers, switchgear *etc*.), which will be embedded within other industry accounts or sourced from overseas.

Table 7. Shares of Electricity supply output and employment: by ANZSIC group, 2006–07. Source: Productivity Commission [132]. Total value added $20.1B (pg. 35 [133]), employment 52,000 [134].

	Industry value added (%)	Employment (%)	Net capital expenditure (%)
Generation	35	22	30
Transmission	11	6	18
Distribution	47	62	48
On selling and market operation	7	11	4
	100	100	100

Figure 9. Projected retail residential electricity price components 2013-14, Australia. Source: Productivity Commission [3].



Most of the LCA analysis of the physical infrastructure of electricity systems has been on generation rather than transmission and distribution (T&D), and where analysis has been undertaken, it attributes around 10% of the overall impact of electricity delivery to T&D [136], however this also includes energy losses, which will be lower with embedded generation. We will assume the embodied energy content of distribution at 4% of the electricity delivered, or double the estimated direct energy inputs.

The addition of storage will reduce the need for network augmentation, hence will lower the marginal cost of T&D, but the magnitude of the embodied energy with batteries and battery cycle loss is much greater than the marginal gain in T&D.

7.7. Employment in Australian PV-Related Industries

Watt *et al*. [49] report the estimated "PV-related labor places" in Australia for 2011 at 10,600. System, installation, manufacture and distribution make up 7,100, with financial, legal, REC traders, consultants and analysts making up 3,000, and research and development including 300. We will take the direct system-related labor plus a 30% proportion for non-direct, and exclude research and development, giving a labor of 8,000-equivalent. Nearly all of the panels and most of the inverters are imported, and it is not apparent that the basic EROI includes sufficient provision for embodied energy due to labor, hence there is probably little "double counting".

In order to estimate labor energy intensity, and using the same methodology as Prieto and Hall ([6], p. 63), we take Australia's total annual energy consumption, which in 2009/10 was 3,703 PJ (Table 6 [134]). In the same year, there were 7.8 million full-time and 3.3 million part-time workers [21]. Assuming that part-time workers work a third of the hours of full-time equates to 8.9 million full-time equivalent workers. Therefore as a crude estimate, the national labor energy intensity is 418 GJ (116 MWh) per full-time productive worker (compare Prieto and Hall's estimate for Spain of 297 GJ).

Multiplying this by the PV-related labor places equates to 3,343 TJ (929 GWh). This assumes that PV-related labor makes use of the normal activities provided by society.

There was 837 MW of PV installed in Australia in 2011 [49]. Taking a peak power of 0.14 kW per m^2 of panel equates to a panel area of 6 million m^2. Thus dividing the panel area into the estimated labor-related embodied energy equates to 155 kWh/m^2.

7.8. Extended EROI

Taking the four additional components discussed, we arrive at an "extended EROI" of 2.0 and 2.3 respectively, given a "basic EROI" for the PV system of 5.9 and 9.4 (see Table 8).

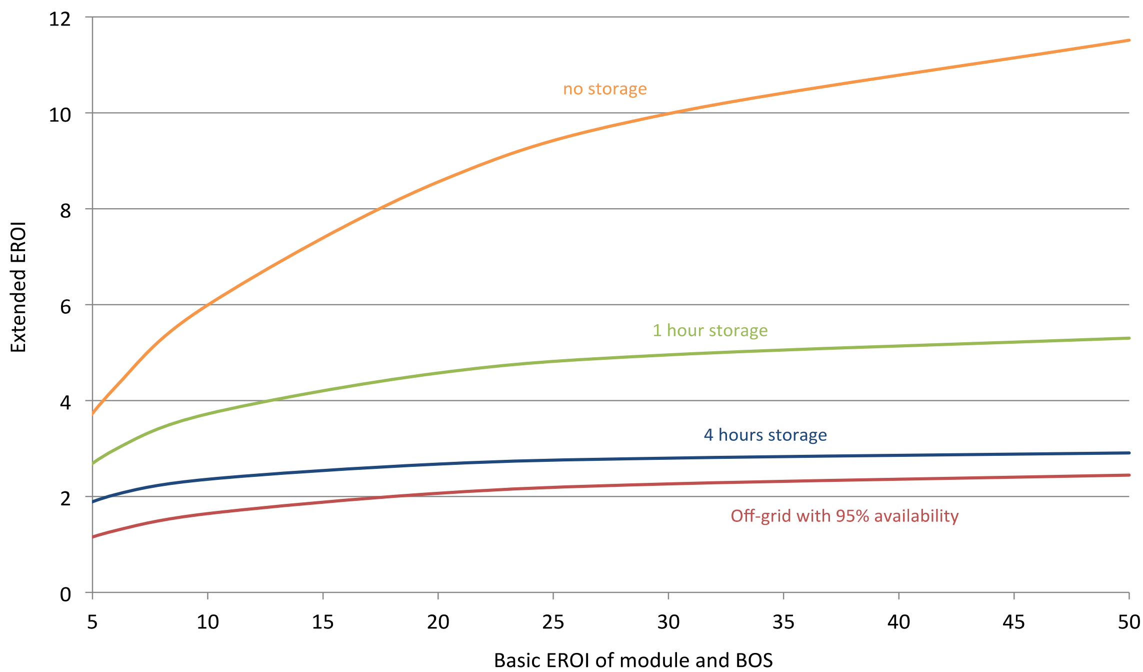
Figure 10 depicts the "basic EROI" with conventional boundaries *versus* the "extended EROI" while holding the other factors constant. The key insight is that the additional downstream energy impacts included in the extended EROI overwhelm the resulting EROI at high basic EROI, and the addition of upstream energy impacts would lower the EROI further. It suggests that the strong focus on developing a superior solar cell overlooks the observation that the "extended EROI" will always be constrained by the weakest links. The critical problem is that PV requires storage to increase its value to the network, but storage significantly undermines its energy-return. This contrasts with conventional electricity generation in which the storage is built into the primary energy source (*i.e.*, coal, gas, uranium, hydro).

Note that this brief analysis has selected the most important additional elements, provides a static snapshot, and the calculation carries significant uncertainties. Hence this analysis is meant to be taken as indicative rather than precise.

Table 8. Calculation of "extended EROI" (includes downstream energy impacts).

	Mono-c Si (rooftop)	Ribbon Si (rooftop)
Basic $EROI_{el} = E_{out}/E_{pp}$ (Table 4)	5.9	9.4
E_{out} [$kWh_{el}/(m^2)$] (Table 4)	5355	4973
E_{pp} [kWh/m^2] (Table 4)	905	530
E_{batt} [kWh/m^2] (for 4 hours, Table 5)	1108	1005
E_{batt_loss} = 5% x E_{out} [kWh/m^2] (Section 7.4)	268	249
E_{dist} = 4% x E_{out} [kWh/m^2] (Section 7.6)	214	199
E_{labor} = [kWh/m^2] (Section 7.7)	155	144
Extended $EROI_{el} = E_{out}/(E_{pp} + E_{batt +} E_{batt\_loss} + E_{dist} + E_{labor})$	2.0	2.3
Extended energy payback time = life / EROI [yrs]	15	13

Figure 10. "Basic EROI" with conventional boundaries *versus* "extended EROI". "No storage" includes labor and pro-rata allocation for distribution, "storage" also includes battery embodied energy and battery cycle loss, and "off-grid" only includes module, BOS and batteries.



8. Conclusions

Much of the literature on PV explores its theoretical potential, and most large-scale Australian and international renewable energy plans include a high penetration of PV. However, there is a dearth of rigorous analysis exploring whether the radical grid transformation that is required to accommodate large scale intermittent generation offers the most promising pathway to a near-zero emission electricity supply within the time frame discussed in climate policy.

This paper shows that it may be technically possible to integrate a high penetration of PV in Australia, but that the economic and energy cost erodes much of the benefits; declining module costs are necessary but not sufficient to permit PV to take on a primary role in the electricity system. Future developments in PV, storage, and integration technologies may eventually allow PV to take on a greater role, but in the time horizon usually discussed in climate policy, there is limited prospect of transformative technologies emerging on the commercial scale required that would allow PV to take on a meaningful primary role.

In a grid dominated by unsequestered coal and gas, PV provides a legitimate source of marginal emission abatement with high, but declining costs. But the short-run tactical response of the expansion of PV without storage works against a long-run strategic approach to deep emission cuts, which will ultimately require the successful adoption of one or more of the candidate low-emission baseload technologies. The greatest strength of PV lies in being embedded within the low voltage network as a supplementary power source, where it can potentially provide valuable network support, but will require reform of the electricity market along with a substantial decline in lifetime battery cost.

Conflict of Interest

The author declares no conflict of interest.

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