

May 2015

Sundown, sunrise

How Australia can finally get solar power right

Tony Wood and David Blowers



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Overview

About 1.4 million Australian homes have installed solar panels on their roofs since 2001. It is the largest take-up of photovoltaic (PV) solar systems of any country. These home owners wanted to save money, depend less on the electricity grid, and play their part in tackling climate change. But lavish government subsidies plus the structure of electricity network tariffs means that the cost of solar PV take-up has outweighed the benefits by almost \$10 billion.

By the time the subsidies finally run out, households and businesses that have not installed solar PV will have spent more than \$14 billion subsidising households that have. Australia could have reduced emissions for much less money. Governments have created a policy mess that should never be repeated.

Even after the closing of the feed-in tariff programs that comprised a large part of the subsidies to solar PV owners, installing a solar PV system today makes financial sense in all capital cities except Melbourne. That will change if tariffs that better reflect the cost of running the network come into force. These tariffs, which federal and state ministers have agreed to introduce, will remove a second subsidy to solar PV owners. In all states, it will no longer be profitable to put panels on the roof.

But that will soon change. The falling cost of solar coupled with progress in battery storage technology will transform the century-old, centralised grid. Households will have a renewed incentive to install solar. They will store the electricity they generate during the day and use it in the evening when electricity costs are high. But governments must drive the tariff reform to ensure that this new model of distributed power generation is both effective and fair.

As home batteries becomes widely available, consumers will be able to use the grid less at peak times, reducing load on the network and the need for costly new infrastructure. But the widespread view that people will disconnect from the grid in large numbers is almost certainly incorrect. Both the cost of the battery and the size of the PV system required to maintain a reliable power source will deter nearly all urban households from going off-grid. The death spiral, the end of the network through falling customer numbers, will not occur.

Nevertheless, the new world of distributed power will profoundly challenge the business models of generators, grid operators and retailers. In rural areas, individuals, clusters of houses and even small towns may find it economically viable to disconnect from the grid. In cities, consumers will draw down less power as they generate and store their own.

Policy reform is urgently needed to support these changes. The regulation of networks must be tightened so that consumers do not pay for more surplus infrastructure. Even with these reforms, falling power use is likely to make some existing infrastructure redundant. Governments must decide now who will pay for these expensive asset write-downs when they are needed.

The journey to a new model of electricity delivery has begun. Already it has seen big mistakes and much waste. If we manage the transformation poorly, consumers will pay again. If we do it well, everyone can benefit from a more efficient, sustainable and affordable electricity system. Solar power in Australia will finally find its place in the sun.

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1 From the grid to distributed generation

For a century, Australia's electricity system has been built around generation from a central source. Almost all our electricity comes from coal, natural gas and water. Typically, large-scale power plants produce electricity at or near the sources of coal, gas and water then dispatch it to consumers through the electricity grid.

But new technologies profoundly challenge this model. Photovoltaic (PV) solar, wind and biomass use fuel sources that are abundant in most locations, and can generate power at a much smaller scale than large, centralised generators. In many cases it makes sense for these technologies to generate electricity at or near the place where the power will be consumed. This is called distributed generation, and one form of it, solar PV, has emerged most strongly in Australia.

Solar PV for households has been supported by generous subsidies and incentives from state and federal governments. Nearly 1.4 million households now have solar PV panels on their rooftops, a higher proportion of all households than any country in the world.¹ Households that have always been consumers of electricity are becoming *prosumers* — someone who produces as well as consumes — and are changing their relationship with the grid. Households with solar PV still use the grid to access electricity when their solar panels aren't producing, but they also use it to sell any excess energy they produce.

This report focuses on the emergence of small-scale solar PV, the most common form of distributed generation. It examines the

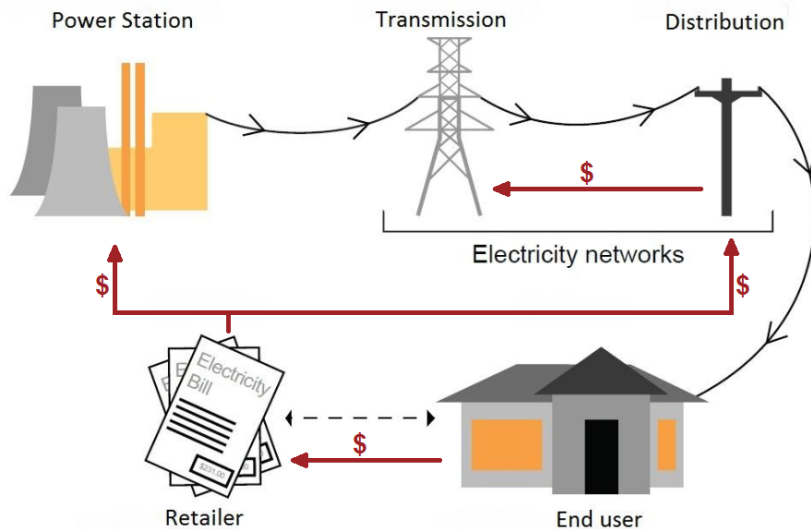
benefits and costs that have accompanied its emergence and how these are changing with developments in technologies, tariffs and subsidies. Finally, it recommends changes to policies and regulations to address barriers to the adoption of distributed generation where it is an economically efficient alternative to the traditional grid.

1.1 What is the grid and who pays for it?

Getting electricity to the user involves three stages: generation, transmission, and distribution. The latter two are usually known as the network or grid. The high-voltage transmission network transports electricity from centrally located power stations to local substations. The low-voltage distribution networks transport this electricity into homes and businesses. Figure 1 shows the system of electricity and who pays for it.

¹ Mountain and Szuster (2014)

Figure 1: How electricity and payments flow through the power system



Source: Grattan Institute

Transmission and distribution networks carry power through the National Electricity Market (NEM) to more than 9.5 million households and businesses in eastern Australia. A separate grid, the South West Interconnected Network, services consumers in southern Western Australia.

1.2 Regulated networks and the problem of peak demand

Transmission and distribution businesses are natural monopolies. To prevent them using their monopoly power to drive up prices, independent regulators — the Australian Energy Regulator (AER) in the NEM and the Economic Regulation Authority (ERA) in

Western Australia — decide the prices they can charge.

Every five years each network business presents the regulator with a proposal for how much revenue it requires to invest in, build, operate and maintain infrastructure. These costs depend on the size of the network, and the size of the network depends on forecasts of peak demand.

Peak demand is the amount of power used at the point in time that puts maximum load on the network. This point is usually near the end of a hot day in summer in all states except Tasmania (where it is in winter). Although it only occurs during a very brief period, peak demand is vital to network businesses. If they do not meet it their network is likely to fail, causing blackouts and huge damage to their reputations.

When peak demand is forecast to increase, network businesses traditionally respond by investing in new infrastructure to make the grid bigger. Under the regulated monopoly model of electricity the businesses are entitled to a return on their investments for the lifetime of the assets, which is generally several decades, and they pass on these costs to consumers in charges. That is why these forecasts of peak demand are so important. If they are too high, the result will be unnecessary investments, an overpriced network and unduly high power bills. This is what has happened in Australia over the past decade.

1.3 Falling consumption and peak demand encourage alternatives

Historically, peak demand and total electricity consumption grew at similar rates, but since 2000, changes in the way we use electricity drove peak demand to grow faster than total consumption for several years, as Figure 2 shows.

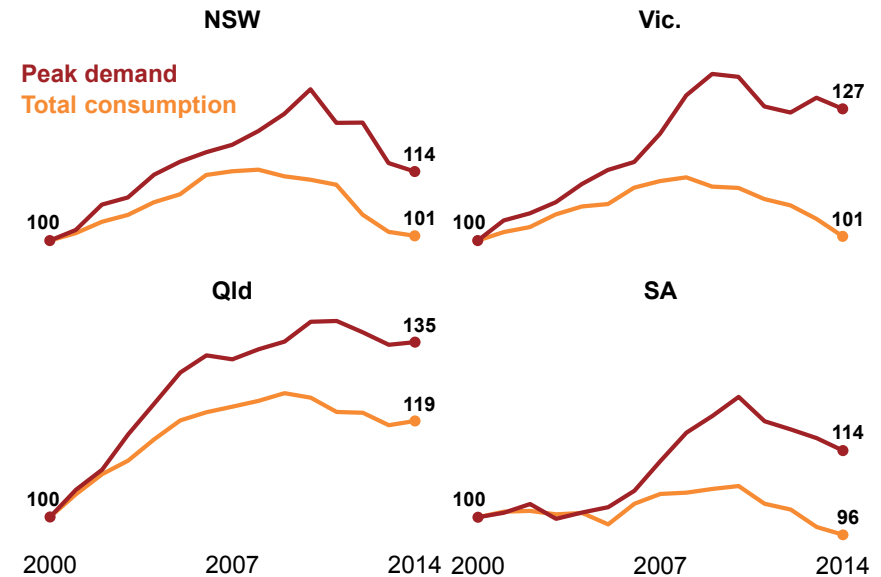
Since 2008, total consumption stopped growing and has declined steadily in New South Wales, Victoria, Queensland and South Australia. It is back to 2000 levels in all states, apart from Queensland. While peak demand continued to rise as overall consumption declined, more recently it has also fallen, although it is still well above 2000 levels.

More efficient appliances, steep price increases and the impact of high exchange rates on manufacturing have all helped to reduce electricity use. The adoption of solar PV has also reduced consumption of electricity from the traditional, centralised system. These factors help to reduce peak demand as well.

Unfortunately neither the industry nor the regulator anticipated these falls in total consumption and peak demand. As a result, many of the networks are bigger than we need and cost more than they should.

In a competitive market, falling consumption usually forces suppliers to lower their prices. But as regulated monopolies, network businesses are entitled to a fixed return on their investments. It may be low, but in exchange the network businesses do not bear the cost of falling consumption. Instead, they simply put up prices to get their return.

Figure 2: Peak demand has grown faster than total demand
Index of peak demand and total consumption for electricity by state
100 = year 2000



Note: peak demand measured as a 3-year moving average to reduce volatility in the measure.

Source: Grattan analysis of AEMO (2015a)

These changes have substantially increased the average price of each kilowatt hour of electricity. In Queensland, for instance, increased infrastructure investment combined with falling consumption has been the primary cause of an 86 per cent rise in retail electricity prices in real terms since 2007.² Rising electricity prices encourage consumers to look for ways to reduce their reliance on grid-provided electricity. One of the solutions they have turned to is solar PV.

1.4 The rise of distributed generation

Unlike centralised, large-scale power stations that transmit electricity to the end user over large distances, distributed generation comes in smaller units installed at or near the place where the power is used. The users vary from individual homes or businesses to entire communities that may have no connection to the centralised system.

In Australia, distributed generation has traditionally meant the use of diesel generators to power remote homes and communities, or as a back-up source of power for businesses in grid-connected areas. In the past 20 years it has become increasingly common to combine diesel generators with solar PV, leading to cleaner and usually cheaper electricity. More than a third of detached and semi-detached houses in remote areas have installed solar panels, sometimes combining them with lead-acid batteries to create their primary power source and turn the diesel generator into a back-up for periods of low sunshine and high usage.

² ABS (2014). Recent price determinations by the AER have lowered the rates of return network businesses receive on their investments, which should see reductions in network charges for consumers.

But in the past decade, most distributed generation is found in built-up areas, and the most common form of it is solar PV.

1.5 Germany, China and the falling price of solar

Germany has invested heavily in solar PV. It has about the same number of systems as Australia (1.4 million at the end of 2014), yet its population is almost four times as large.³ But because Germany subsidised commercial and large-scale installations as well as households, more than 85 per cent of Germany's solar PV capacity comes from systems larger than 10 kilowatts.⁴ By contrast, more than 90 per cent of Australia's capacity comes from small residential systems, of less than five-kilowatt capacity.⁵

At the end of 2013, Germany accounted for more than 25 per cent of the world's total installed capacity of solar PV. Australia accounted for only 2.3 per cent, reflecting our relatively small population and low investment in commercial and large-scale solar PV systems, as Figure 3 shows.

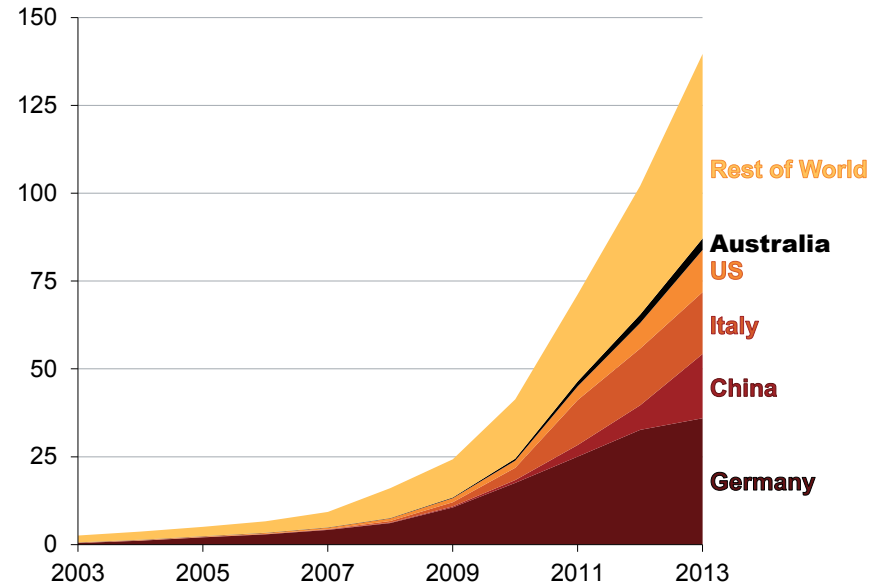
³ Fraunhofer ISE (2015)

⁴ Ibid.

⁵ CCA (2012)

Figure 3: Australia accounts for a relatively low proportion of global solar PV capacity

Cumulative installed global solar PV capacity, gigawatts



Source: BP (2014)

Germany has been responsible for much of the fall in the global price of the technology. As early as 1991, it provided feed-in tariffs for renewable energy, while the 100,000 homes scheme, launched in 2000, provided loans to homeowners and businesses to help them install solar PV. For a short time, strong demand led to Germany becoming the world's leading installer and manufacturer of solar PV. German demand also encouraged manufacturing of solar PV in other countries, especially China, which has been able to significantly reduce manufacturing costs.

China's increased share of the manufacturing market is due to lower wages and high domestic and global demand. China also provided substantial subsidies for manufacturers of solar PV, which subsequently led to anti-dumping action by several countries, including the U.S. It now has the second largest installed capacity of solar PV behind Germany, and accounts for more than half of solar PV manufacturing in the world.⁶

As China brought down manufacturing costs, the price per watt of installed residential systems in Australia fell rapidly between 2008 and 2013, falling from about \$12 per watt to under \$3 per watt.⁷ The next chapter examines the other reason why so much solar power was installed in Australia during this period.

⁶ Earth Policy Institute (2013)

⁷ APVI (2014)

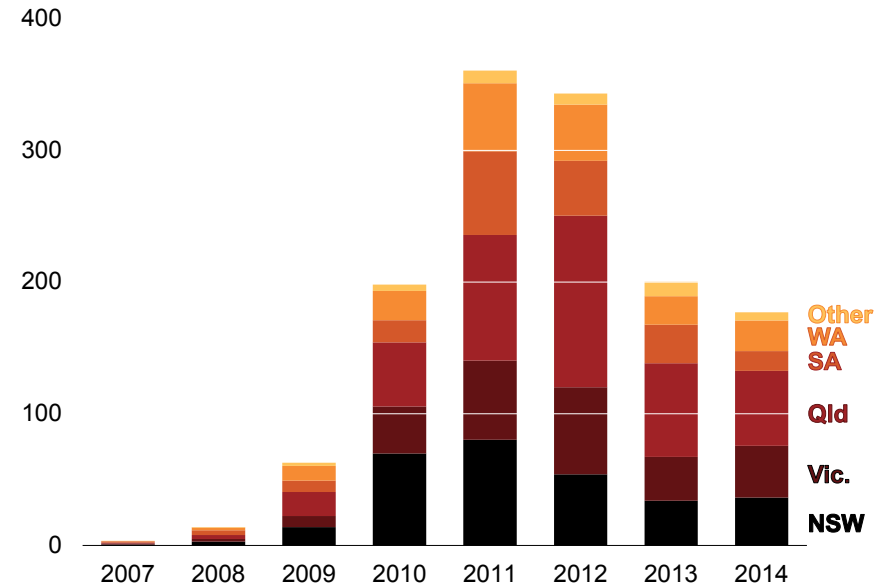
2 Solar PV: a good deal for some, a high price for all

Commonwealth and state government policies have encouraged huge household take-up of solar PV, provided a big boost to the renewable energy industry and helped to reduce greenhouse gas emissions.⁸ Yet the results have come at a high cost. Certificate schemes and feed-in tariffs, along with poorly structured network tariffs, have provided \$14 billion worth of subsidies to solar PV owners that all other power users have had to pay for. This chapter examines these subsidies and their effects on the electricity system.

2.1 Subsidy one: certificate schemes and feed-in tariffs

Certificate schemes and feed-in tariffs pay a direct subsidy to households to encourage them to install solar PV. From 2010 the Federal Government has encouraged households to install solar PV through the Small-scale Renewable Energy Scheme (SRES), as Box 1 describes. Between 2008 and 2011 state governments supported solar PV through highly generous premium feed-in tariffs. The combination of these subsidies and the falling price of the technology saw a solar PV boom between 2010 and 2012, as Figure 4 shows.

Figure 4: Subsidies drove rapid growth in solar PV installations
 Number of small-scale solar PV installations, thousands



Note: 'Other' includes Tas., ACT, and NT.
 Source: CER (2015)

⁸ These objectives are set out in legislation in the *Renewable Energy (Electricity) Act 2000*, see Australian Government (2000).

Box 1: SRES, child of the Renewable Energy Target

In 2001, the Commonwealth Government introduced the Mandatory Renewable Energy Target (MRET) to increase the amount of electricity generated from renewables by 9,500 gigawatt hours per year by 2010. In 2009 the scheme was replaced by the Renewable Energy Target (RET). Now at least 20 per cent of electricity generation would come from renewable sources by 2020.

To provide certainty to the market, the target was expressed as a total of 45,000 gigawatt hours of electricity to be generated from renewable sources by 2020. At the same time, the Government introduced an additional incentive, under which a 1.5 kilowatt solar PV system would receive a subsidy that was five times that for other forms of renewable energy. As a result, installations of solar PV were much higher than expected, and this caused the market price of Renewable Energy Certificates to crash from well over \$40 to below \$30 (this is the subsidy available for each megawatt hour of renewable energy produced). An effect of this lower price was to discourage investment in large-scale projects.

A year later, the scheme was split in two. The large-scale RET was given a target of 41,000 gigawatt hours of electricity produced from large-scale renewable electricity generation and the Small-scale Renewable Energy Scheme (SRES) a target of 4000 gigawatt hours from small-scale systems. Unlike the large-scale target, the SRES target is not fixed. In 2013 solar PV produced 6400 gigawatt hours of energy, far exceeding the initial target.⁹ It is expected to produce 11,000 gigawatt hours in 2020.¹⁰

The SRES trades in certificates. When consumers put a solar PV system (or a solar hot water system or heat pump) on their roof, they receive one Small-scale Technology Certificate (STC) for every megawatt-hour of electricity they are forecast to generate over a 15-year period (the forecast depends on the system's size and location, since some places get more sun). Owners sell the certificates to offset the upfront cost of the system.

Normally the system installer sells the certificates to an energy retailer, either directly or through a clearing house, on behalf of the owner. In return the installer gives the owner a discounted price on the PV or solar hot water system. Electricity retailers have an obligation under the SRES to buy STCs, and pass the cost on to consumers' energy bills.

⁹ Warburton, *et al.* (2014)

¹⁰ CCA (2012)

Feed-in tariffs pay households for the electricity their PV solar system generates and exports to the grid. The premium tariffs offered during the boom days of 2008 to 2011 mean that for 15 years, eligible Victorian households receive a minimum of 60 cents for every kilowatt hour they export to the grid, more than four times the typical retail tariff in 2009. Until 2028, Queensland and South Australian households will receive at least 44 cents per kilowatt hour. In NSW, the 60 cent feed-in tariff is only contracted for seven years, but households are paid for all the electricity they produce, and are able to purchase additional electricity from the grid at a much lower rate.

Households responded enthusiastically to the tariffs and took up solar PV at a rate much faster than state governments had anticipated and budgeted for. Alarmed, most states responded by lowering the tariff for new households. Tariffs went from “premium” to “transitional”.¹¹ Eventually, all states closed the schemes. Four — New South Wales, Victoria, South Australia, and Western Australia — removed the tariff in 2011 and early 2012 and installations fell sharply in 2012 and 2013. Queensland kept premium tariffs until mid-2013, and installations grew by more than 35 per cent in 2012, but have more than halved since the tariffs were removed. Nationally, the number of systems installed in 2014 was less than half the number installed in 2011.¹²

Feed-in tariffs also created an employment bubble. When the incentives were wound back, it burst. The number of people employed in the rooftop solar industry in the 2013-14 financial

¹¹ Transitional feed-in tariffs were typically one-for-one: households received the retail electricity tariff for every kWh exported.

¹² CER (2015).

year was just over half that of two years earlier.¹³

The story was similar with an earlier PV support program, the Solar Photovoltaic Rebate Program. It led to a six-fold increase in PV generation capacity in the 2000s, but it had the same boom-and-bust characteristics as feed-in tariffs. It also subsidised solar PV owners at the expense of everyone else and had little benefit as an industry assistance measure.¹⁴

Households who install solar PV today receive a feed-in tariff that more closely reflects the average wholesale price of electricity — typically between six and eight cents a kilowatt hour.

Yet premium tariffs continue to be paid to households who installed solar PV before the schemes were closed. Because network businesses are allowed to recover the costs of these subsidies from their customer base, subsidies paid to one group of consumers must be funded by another. In other words, households with feed-in tariffs are being subsidised by everyone else.

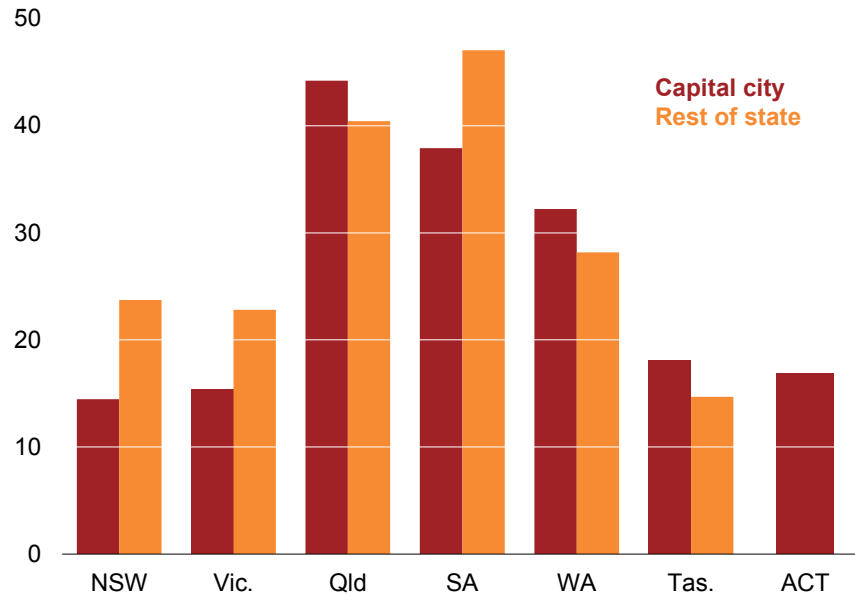
The schemes in Queensland and South Australia were particularly attractive and remained open for the longest time. More than 40 per cent of owner-occupied houses have installed solar PV in those states, as Figure 5 shows. In Western Australia the penetration rate has been helped by high levels of sunshine, while consumers in rural and regional Victoria and New South Wales have made high savings because their retail power prices are high.

¹³ ABS (2015)

¹⁴ Macintosh and Wilkinson (2010)

Figure 5: Solar PV is most common in states that had the most generous feed-in tariffs

Rooftop solar PV penetration rates, percentage of owner-occupied houses, Feb 2015



Note: includes detached and semi-detached houses.
Source: Grattan analysis of CER (2015), ABS (2011)

2.2 Subsidy two: network tariffs that do not properly reflect costs

A second subsidy associated with solar PV is related to how electricity is priced. Peak demand determines the cost of the network, which in turn determines the amount of our power bills. Yet the cost of meeting peak demand has no effect on the bills of households and small businesses, which are typically charged the same or a similar amount for each kilowatt hour of electricity, regardless of when it is consumed.

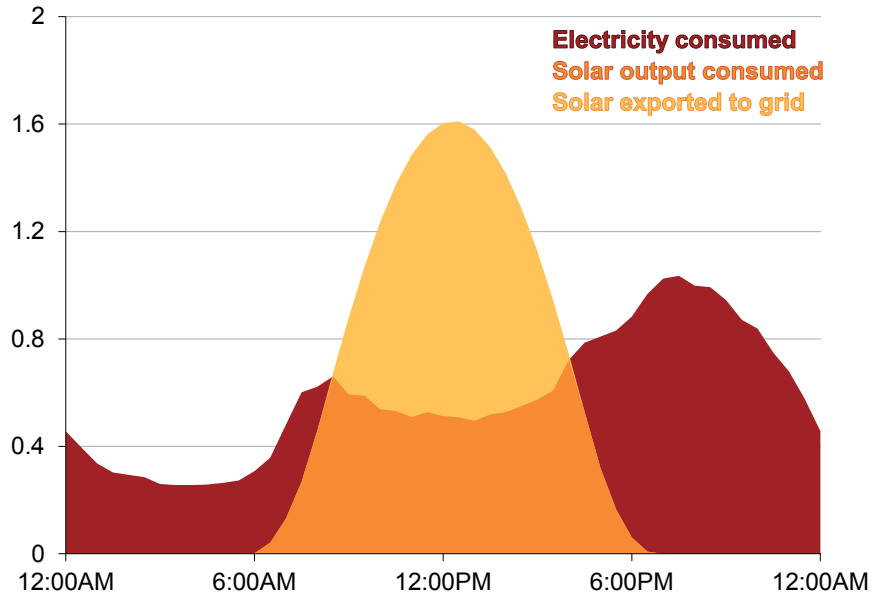
Under the current volumetric tariffs, households who do not use much electricity overall but use a lot during peak periods when the strain on the network is high, are being subsidised by other households. Owners of air-conditioners, for example, generally consume large amounts of electricity during peak times and, as a result, are being cross-subsidised by other electricity users.

Solar households are in a similar position. Since they consume less electricity overall, they pay less than other households do to use the network. But because peak use of the residential network usually occurs in the early evening when there is little or no solar output, solar households on average place as much strain on the distribution network as those without solar PV do.

Figure 6 shows that a typical Melbourne household demands the most energy at around 7pm, but a north-facing solar PV system stops producing energy at about 6.30pm. In other words, most solar households require just as much network infrastructure as everyone else but are paying less. All consumers are subsidising their reduced payment.

Figure 6: Household consumption is typically highest when solar output is low

Average power consumption and 3-kilowatt solar PV output, typical Melbourne household, kilowatts



Note: solar PV system is north-facing with a 30 degree tilt and an average efficiency of 80 per cent. The y-axis measures household's average demand or solar production at a point in time (measured in kilowatts), while the shaded areas represent the average amount of energy consumed or produced across the day (measured in kilowatt hours).
 Source: Grattan analysis of Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012).

Cost-reflective tariffs greatly reduce these cross-subsidies by making the price for consuming electricity during peak periods greater and reducing prices at other times. They also encourage households to spread their electricity consumption more evenly across the day, placing less strain on the network, and thereby delaying or avoiding the need for infrastructure upgrades. Their introduction would not change the total revenue paid to network businesses but in the long term consumers will benefit through lower electricity prices.

Grattan's 2014 report, *Fair pricing for power*, proposed a new design of network tariffs in order to reduce cross-subsidies among consumers, and to create incentives for consumers to reduce the load they place on the network.¹⁵ The report proposed the introduction of a demand charge which reflected the maximum load that households place on the network during peak times.

In November, 2014, the Australian Energy Market Commission (AEMC), the rule maker for electricity and gas markets, issued a determination that requires distribution network businesses to develop by 2017 electricity pricing that better reflects the cost of building the network¹⁶. If proper cost reflective tariffs are introduced, households will pay directly for the amount of network infrastructure they use — especially at peak times when the network is under greatest strain and is most expensive to run — while paying less for the overall amount of electricity they consume. Under this reform, households with solar PV would pay more to use the network than they do today.

¹⁵ Wood, et al. (2014)

¹⁶ AEMC (2014)

2.3 Subsidies are expensive and inefficient

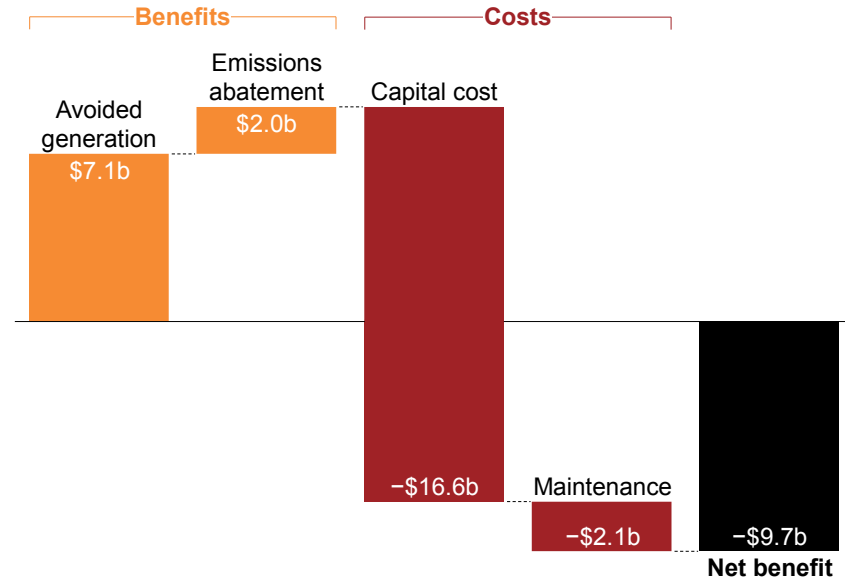
The widespread adoption of solar PV has brought economic benefits and costs.¹⁷ Switching from centralised electricity generation, mainly from fossil fuels, to distributed, solar PV generation brings two main benefits. First, solar PV has reduced the amount of electricity that needs to be produced. This represents a benefit of \$7 billion of avoided generation costs.

Second, electricity generated from solar PV will reduce emissions by an estimated 66 million tonnes of CO₂ by 2030 — or about four million tonnes a year. Installed solar PV will achieve less than 10 per cent of the abatement required to achieve Australia’s 2020 emissions target over the next five years.¹⁸

If those emissions are priced at \$30 a tonne, the reduction represents a benefit to society of about \$2 billion. Once the electricity savings are added in, the total benefit is just over \$9 billion.

But purchasing, installing and maintaining the solar PV systems until 2030 will cost \$18.7 billion, outweighing the benefits by more than double. The net economic cost is \$9.7 billion, as shown in Figure 7.

Figure 7: Rooftop solar PV has come at a large cost to society
Aggregate net present benefits and costs to society of solar PV systems installed from 2009, \$2015



*Note: includes all costs and benefits from 2009 to 2030. Does not include solar PV systems yet to be installed.
Source: Grattan analysis of CER (2015), BOM (2015), Solar Choice (2015), APVI (2014), AEMO (2015b), ABS (2014), IPART (2012), ESC (2014), QCA (2013), ESCOSA (2014), Synergy (2014), OTTER (2015).*

¹⁷ We have analysed the aggregated costs and benefits to society from nearly 1.4 million solar PV systems installed since 2009. Some costs and benefits have already occurred, others are projected until 2030. See *Sundown, Sunrise: Technical Appendices* for details.

¹⁸ Grattan analysis of Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012), AEMO (2015b).

In calculating the net benefits and costs of solar PV, our analysis estimates that the economic cost of the emissions reductions to 2030 due to solar PV is more than \$175 a tonne. By contrast, the Commonwealth Government's recent auction under the Emissions Reduction Fund purchased emissions reduction at an average price of \$13.95 a tonne. The Warburton review of the RET calculated that the cost of emissions reduction under the Large-scale Renewable Energy Target was \$32 a tonne.¹⁹

2.4 Solar PV may bring additional benefits to electricity consumers

2.4.1 The merit order effect

Households with solar PV may help to reduce wholesale generation prices through what is known as the "merit order effect". It takes its name from the way in which the NEM operates. Generators bid at five-minute intervals to dispatch electricity to the grid. Those who have submitted the lowest bids get to dispatch their electricity before higher cost generators, until the total amount of electricity dispatched equals demand during that five-minute period. All generators are paid the price bid by the last accepted generator.²⁰

The generation of electricity by solar PV installed on household and business roofs reduces the amount of electricity demanded from the wholesale electricity market. This means that the last accepted generator will now be lower cost than previously,

¹⁹ Warburton, *et al.* (2014). This is the value if emissions are not discounted in the future. Even under the discounted value, emissions reductions cost \$62 a tonne.

²⁰ AER (2014)

thereby reducing the price received by all generators and lowering the price for consumers.

Some industry analysts have used the merit order effect to justify premium feed-in tariffs.²¹ Yet merit order effects can occur in other ways that do not lead to financial reward. When a household reduces its electricity consumption by installing more efficient appliances, or when a new electricity generator enters the wholesale market, both reduce wholesale prices for everyone.²² But neither party receives compensation and they do not expect it.

Lowering wholesale prices does not constitute a net economic benefit to society, which is why it does not appear in the cost-benefit analysis presented on page 15. Instead, it is a short-term financial transfer from existing generators to electricity retailers, who may then pass these savings onto consumers. In economic terms, society as a whole does not benefit.

2.4.2 Impact on network peaks

Lowering peak demand may delay the need for future investment to expand and upgrade the network, reducing costs for consumers. Solar PV may impact peak demand in some areas, but the overall impact is likely to be small, even though solar has reduced overall electricity consumption.

Any benefit of solar PV on the distribution network will depend on how it affects peak demand at the feeder or substation level of the network. Across an entire network, peak demand typically begins

²¹ See, for instance McConnell, *et al.* (2013).

²² IPART (2012)

in the late afternoon, when solar PV systems are still producing some electricity. But electricity generated by solar PV does not necessarily align with peak periods at the feeder or substation level, particularly in residential areas where peaks occur later. Figure 8 shows that an increasing penetration of solar PV can have a large effect on electricity demand during the day without impacting on the peak at the feeder level of a residential area.

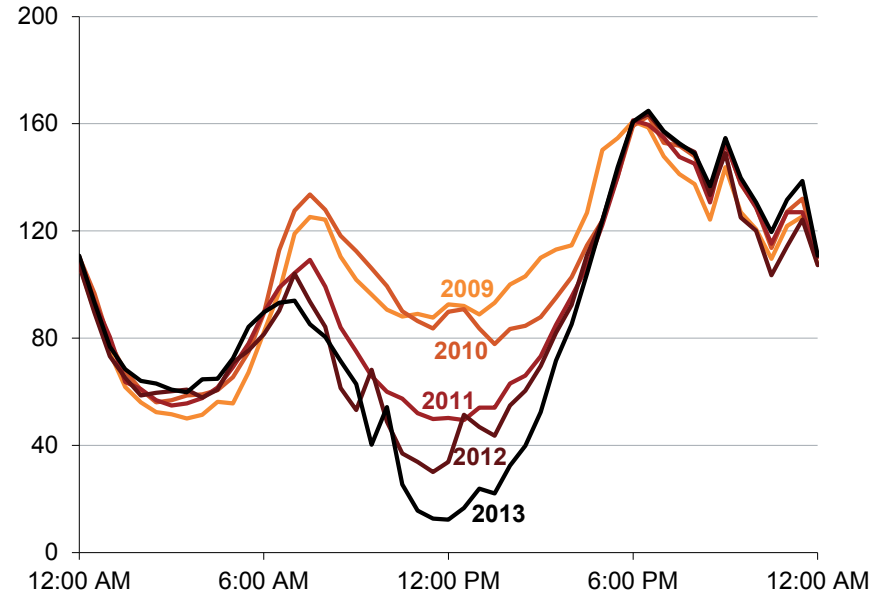
On the other hand, peak demand in the transmission network tends to occur in the afternoon, driven primarily by commercial and industrial users.²³ Solar PV in residential areas can potentially reduce these peaks, since it is still producing in the afternoon.

Solar PV can also have a negative impact on the network. The variation in the amount of electricity produced by a solar PV unit over the course of a day can be dramatic. Sudden cloud cover can abruptly reduce or increase solar production, leading to a surge or sudden drop in household demand for electricity. These changes in the flow of electricity along the grid can put stress on the network, potentially forcing network businesses to invest more to maintain reliability.

It is difficult to quantify the value of the delayed investment and additional operating costs caused by installed solar PV for the transmission and distribution network. What matters is that in the future all customers, including solar PV owners, face price signals to use the network efficiently so they are rewarded fairly when they do.

Figure 8: A high penetration of solar does not necessarily reduce network peaks

Electrical current flowing through a Queensland feeder in a residential area with increasing rooftop solar penetration, amps



Note: recorded on second Tuesday in October of each year.
Source: Energex (2013)

²³ Moyse (2014)

2.5 Subsidies are a \$14 billion wealth transfer

The SRES and premium feed-in tariff schemes created \$10.4 billion worth of cross-subsidies that flow from electricity users without solar PV to those with solar PV, as Figure 9 shows. The second subsidy — unintentionally embedded in the structure of electricity network tariffs — benefits solar PV owners to the tune of \$3.7 billion. As a result of these two cross-subsidies, by 2030 consumers without solar PV will pay consumers with solar PV a total of \$14 billion.

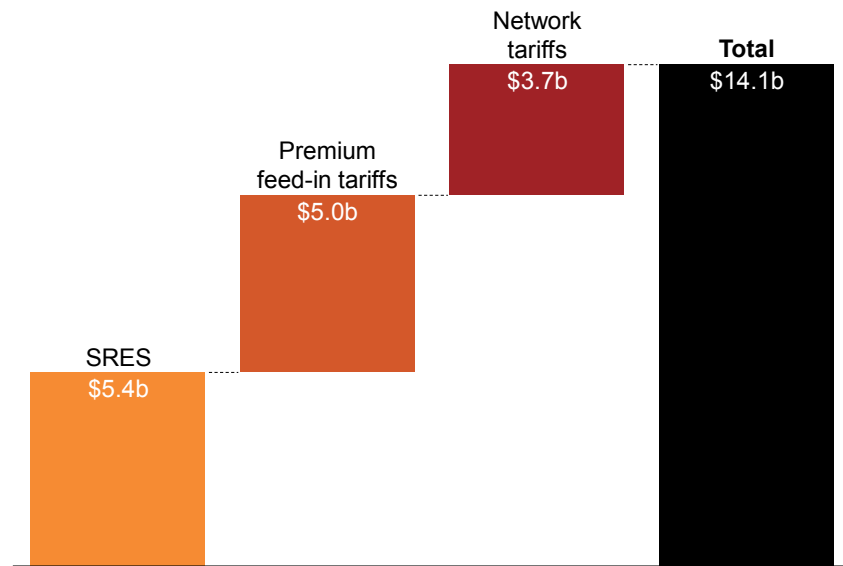
The subsidies are particularly unfair when many renters, apartment dwellers and low-income households are unable to gain the benefits of solar PV.

State governments did not foresee the rapid take-up of solar PV these incentives would create and the costs that followed. They did not implement mechanisms to prevent the costs getting out of control. By the time governments closed the schemes, the damage had been done. The mistakes must not be repeated.

Fortunately, these issues are starting to be resolved. Premium feed-in tariff schemes are closed to new households and the SRES is due to start winding down in 2017. These changes are likely to reduce the yearly savings going to households with solar PV. Chapter 3 examines a tariff reform that could make electricity tariffs more efficient and fair, and make solar power more expensive in the short term but more cost-effective in the long run.

Figure 9: Consumers without solar have paid a lot towards those with solar

Aggregate net cross-subsidies from electricity consumers without solar PV to consumers with solar PV, \$2015



Note: cross-subsidies do not include those from consumers with solar PV to other consumers with solar PV. Includes all cross-subsidies between 2009 and 2030. Source: Grattan analysis of CER (2015), Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012), Energy Australia (2015), Origin Energy (2015), AGL (2015), ABS (2014), ABS (2011), IPART (2012), ESC (2014), QCA (2013), ESCOSA (2014), Synergy (2014), OTTER (2015).

3 The economics of solar PV are changing

This chapter examines whether it is financially worthwhile to install household PV systems given their current purchase prices, electricity tariffs and subsidies. It also considers how the move to cost-reflective electricity prices will change the economics of solar PV, both for households that have already installed it and for those considering it.²⁴ The modelling is outlined in Box 2.

3.1 Under current tariff settings, solar PV is still a good investment

A household that installs solar PV today avoids the cost of electricity consumed when solar panels are producing — between 20 and 35 cents a kilowatt hour in most parts of Australia. If the panels produce more electricity than the household consumes, it earns a feed-in tariff of between six and eight cents a kilowatt hour for the energy exported.

Depending on their location, different households face different costs and benefits for installing solar PV. What may be economically viable for one may be prohibitively expensive for another. Different electricity tariffs are charged in different states and the states have varying levels of sunlight. People at home during the day are likely to consume more electricity when solar panels are producing, whereas households with people working by day and coming home at night are likely to export most of their solar energy.

²⁴ While the financial viability of solar PV is an important determinant of whether a household chooses to install a system on their roof, households may also have other motivations for doing so, such as environmental concerns.

Box 2: An economic model of solar PV

We analysed household consumption data measured at half-hourly intervals, and weather data including solar radiation in order to simulate household consumption over 15 years. The following results consider the costs and benefits to a household installing a three-kilowatt solar PV system today.²⁵ Households are assumed to have sourced a competitively priced solar PV system and retail electricity offer.

The financial viability of installing a solar PV system in each city is determined by the economic concept of 'net present value' (NPV), which takes into account both current and future payments. Because people value a sum of money today more than they would in a year's time, future costs and payments are discounted at a rate of 5 per cent per year (in real terms). The NPV accounts for all costs and payments over a 15-year period, reflecting that most households would expect a payback within this timeframe.

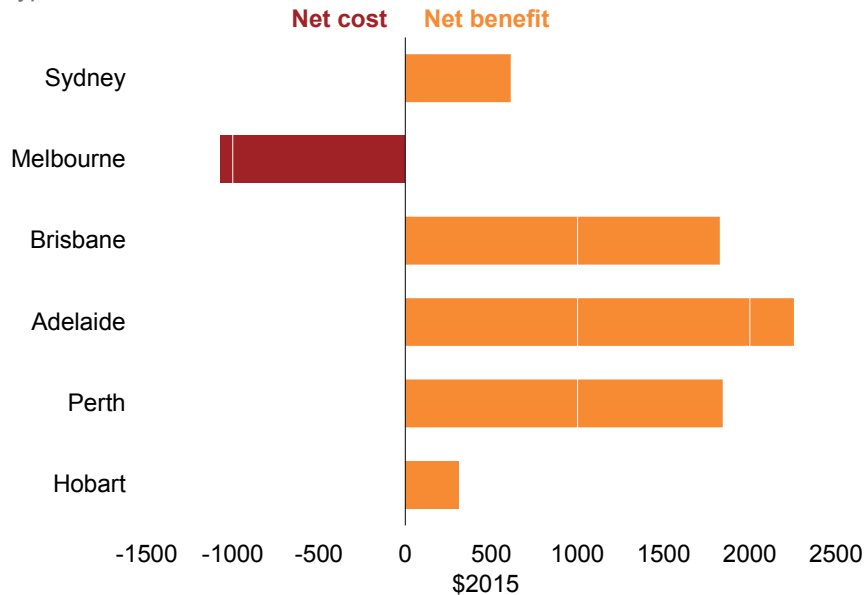
The model assumes that a household is able to install a solar PV system in the optimal position and maintain it over 15 years.

See *Sundown, sunrise: Technical Appendices* for details.

²⁵ The average system size installed since 2014 is 4.4kW, but 3kW is the most commonly installed system size since 2014. For the average households, the optimal system size is between 2kW and 3kW.

Figure 10: Investing in solar PV provides a positive return in nearly all major cities

Net present value of investing in three-kilowatt solar PV system for a typical household



Note: solar PV system is north-facing with a 30 degree tilt and an average efficiency of 80 per cent. NPV calculated using a 5 per cent real discount rate over 15 years. Electricity tariffs assumed to rise by one per cent each year in real terms, with no carbon price. Source: Grattan analysis of Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012), Solar Choice (2015), Energy Australia (2015), Origin Energy (2015), AGL (2015).

Figure 10 shows that the net present value of installing a three-kilowatt solar PV system is positive for a typical household in each capital city — except for Melbourne. This is partly because of the low level of sunlight experienced in Victoria compared to Queensland, for example. It is also because Victorian consumers have lower levels of electricity consumption than in other states due to the amount of gas that is used. The less electricity consumed, the less benefit to be gained from displacing grid produced electricity with solar PV generation.

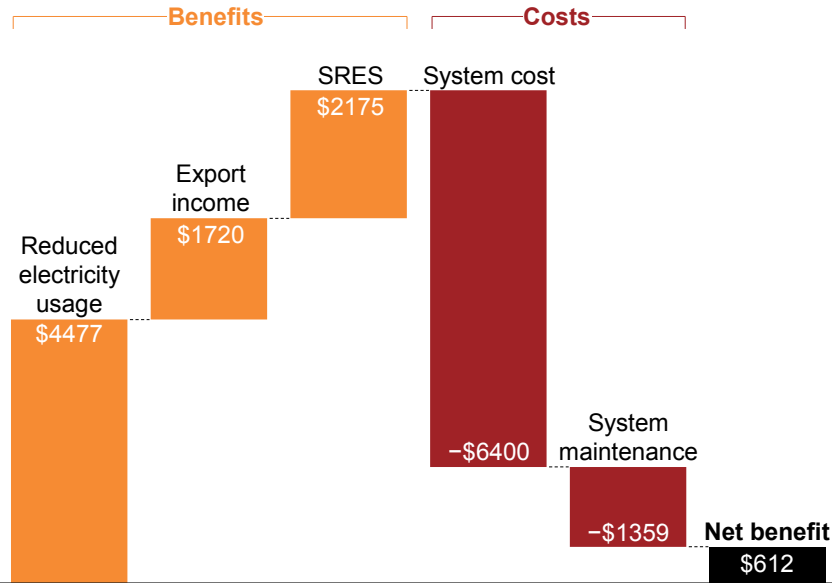
Figure 11 shows the costs and benefits for a typical Sydney household with a solar PV system over 15 years, receiving a feed in tariff of 6.6 cents per kilowatt hour.²⁶ We calculated the benefits as lower bills through reduced electricity usage, income from energy exported to the grid, and the SRES subsidy. In the absence of a price on carbon, the SRES subsidy provides an incentive to households to reduce emissions.

The costs include the total cost of the system (panels, inverter, balance of system costs and installation), and system maintenance (cleaning panels, repairs and inverter replacement cost after 10 years). Over the 15 years, the household came out ahead by \$612, in 2015 dollars.

²⁶ Results for all cities are shown in *Appendix A: Economics of solar PV, extended results (page 55)*

Figure 11: Solar PV benefits households most by reducing their electricity usage

Net present benefits and costs of installing a three-kilowatt solar PV system, typical Sydney household, in 2015 dollars



Note: system maintenance costs include inverter replacement after ten years.
 Source: Grattan analysis of Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012), Solar Choice (2015), Energy Australia (2015), Origin Energy (2015), AGL (2015).

3.2 A new tariff structure will make solar less attractive

Under current electricity pricing and with the SRES subsidy still available, solar PV remains an attractive investment for most households. But recently announced reforms to the regulatory framework for networks will change the way we pay for electricity. Provided they are properly designed, more cost-reflective tariffs will greatly reduce cross-subsidies among electricity consumers. They will also change the economics of the household decision to install solar PV

The AEMC has announced that it will require network businesses to implement cost-reflective network tariffs. But the structure of these tariffs is not yet clear. If they are well designed, they will contain a tariff based not on a household's overall electricity use but on its maximum demand for power at a point in time.²⁷ This demand tariff would better reflect the load a household puts on the network and therefore the cost to the network. By creating an incentive for households to use the network more efficiently, a demand tariff would delay the need for future upgrades to and investment in network infrastructure.

²⁷ This is sometimes referred to as a capacity charge. But there is another definition of capacity charge, where a consumer pays for a maximum level of capacity to be delivered to their premises, which they cannot exceed. We do not consider this alternative in the report.

The new tariffs may also include a critical peak tariff that would apply only at times and in places where the network is expected to be under strain. This tariff would be high, creating a further incentive for households in these areas to use less power at peak demand times, again reducing strain on the network. In return, these customers would be charged a lower price at other times.²⁸

The following analysis examines the economics of solar PV when a household pays to use the network through a demand tariff. We have assumed a tariff that is broadly consistent with initial proposals put forward by network businesses.

The demand tariff is charged monthly. A higher tariff applies in summer to reflect the fact that peak demand is more likely to occur at this time.²⁹ The charge is meant to reflect how much a household uses the existing network, and to encourage it to spread electricity consumption over the course of 24 hours and reduce demand at peak times. Not only does this delay the need for future investment, it is also a much fairer way for households to pay for the amount of network they use. Any household that can reduce its maximum monthly peak by an average of one kilowatt could save more than \$100 a year on its electricity bill.³⁰

However, the change to a demand tariff would reduce the savings of households with solar PV. It would not affect their earnings from selling energy to the grid. But when the network charge is based on a household's maximum demand, households with solar PV pay a similar amount to other households. As a result, solar PV households in most cities would lose more than \$200 a year in savings.

This loss of savings greatly affects whether solar PV is a worthwhile investment. Figure 12 shows that under a demand tariff, a three-kilowatt solar PV system is no longer beneficial in any of the capital cities. The price of the system would need to fall by \$500 in Adelaide, \$600 in Perth and \$800 in Brisbane before a household is able to break even.

Figure 13 shows that a typical Brisbane household with solar PV saves almost \$5700 on their electricity usage under the current tariff but would save just over \$3000 under a demand tariff.³¹ The difference represents the loss of the cross-subsidy that households with solar PV would receive from non-solar households over 15 years.

²⁸ See Wood, *et al.* (2014) for a detailed description of cost-reflective pricing.

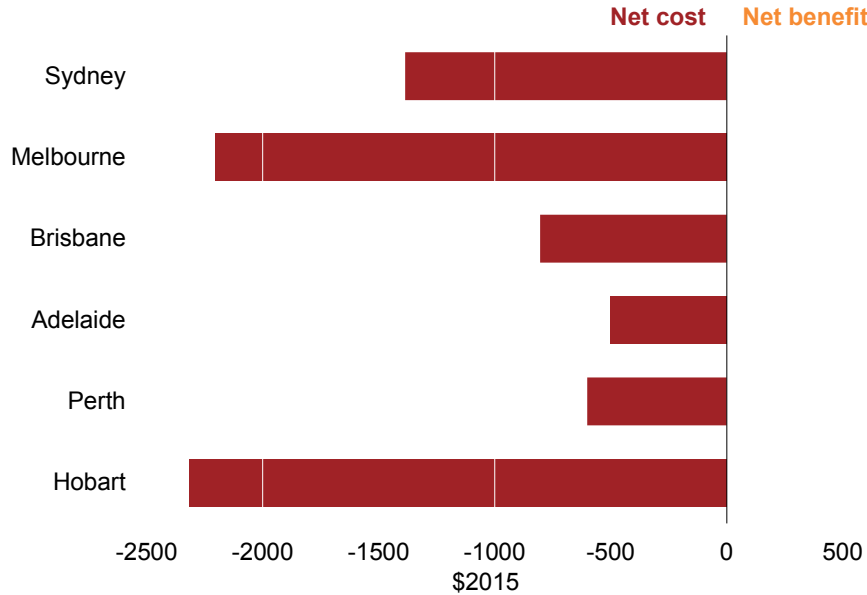
²⁹ Hobart is the exception, where peak demand is more likely to occur in winter. The demand charge is adjusted to reflect this. A minimum monthly demand charge applies so that all households contribute to the existing network.

³⁰ This is based on a demand charge of \$15 a kilowatt for each of the summer months (December through to March), and \$6 a kilowatt for all other months.

³¹ Results for all cities are shown in *Appendix A: Economics of solar PV, extended results (page 55)*.

Figure 12: Investing in solar PV is not financially attractive under a demand tariff

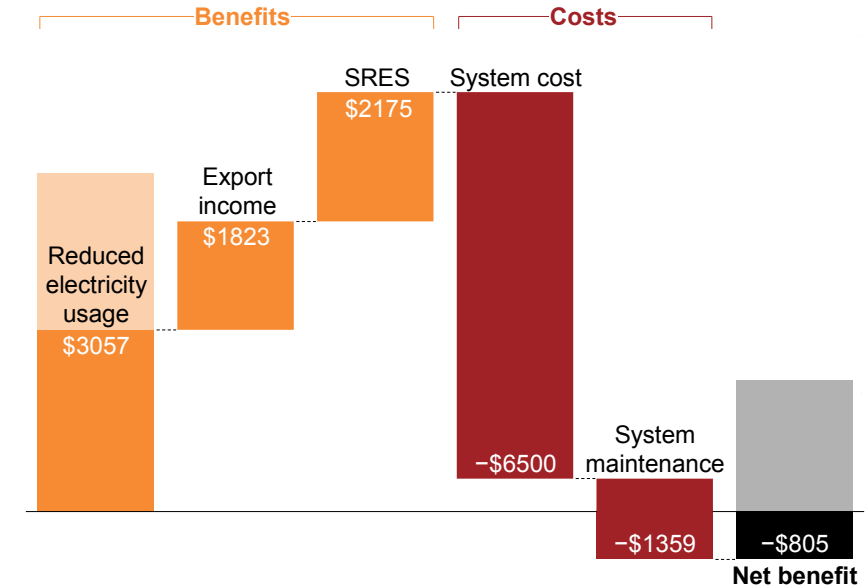
Net present value of investing in three-kilowatt solar PV system for a typical household under a demand tariff



Source: Grattan analysis of Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012), Solar Choice (2015), Energy Australia (2015), Origin Energy (2015), AGL (2015).

Figure 13: A demand tariff reduces the savings from reducing electricity usage

Net present benefits and costs of installing a three-kilowatt solar PV system under a demand tariff, typical Brisbane household, \$2015



Note: system maintenance costs include inverter replacement after ten years. Transparent bars highlight the changes arising from the shift to a demand tariff from the current tariff. Source: Grattan analysis of Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012), Solar Choice (2015), Energy Australia (2015), Origin Energy (2015), AGL (2015).

3.3 Genuine cost-reflective tariffs are essential

The move to more cost-reflective tariffs by 2017 is important to reduce unfair cross-subsidies among electricity consumers. But there is no guarantee that the change will be properly implemented. Because demand tariffs create some losers, they will face some opposition. State or territory governments may intervene so that watered down versions lessen the impacts on consumers but fail to significantly reduce the cross-subsidies. They should resist this temptation by making three key reforms:

3.3.1 Implement demand tariffs effectively

Effective implementation of demand tariffs faces a number of challenges. First, there is a trade-off between giving consumers an accurate price signal and protecting them from sudden increases in prices. The structure of demand tariffs already announced suggests that network businesses are favouring the latter approach. For instance, basing the demand tariff on a consumer's maximum demand each month gives a relatively weak price signal to customers.

For the tariff to give a strong and accurate price signal, the time when it is applied should coincide as closely as possible with periods of peak demand during summer months (in all states except Tasmania). A monthly demand charge has only a weak connection to these peaks, which reduces its ability to create more efficient use of the network.

Second, if the implementation of demand tariffs is voluntary, those who benefit from the current tariff structure, including those with solar PV, are unlikely to opt in. Demand tariffs would then only

remove cross-subsidies among consumers over a long period of time, as consumers respond to rising volumetric tariffs by switching to demand tariffs. If cost-reflective pricing is to be voluntary initially, it should be made mandatory by 2020. This will be essential for demand tariffs to work in the long run.

Third, the absence of smart meters or interval meters for many households outside Victoria makes the broad take-up of demand tariffs more difficult. A roll-out of either interval meters or smart meters will be needed. In the interim, more cost-reflective tariffs could still apply where customers do not have more advanced meters. Instead of charging customers on their individual maximum demand, customers could be charged according to the maximum demand in the area in which they live. Consumers with relatively flat consumption would have an incentive to install a smart meter and this would lead to a price reduction for them.

3.3.2 Introduce critical peak pricing

Demand tariffs are not perfect in reflecting the costs imposed on the network, but they will be a significant improvement over current tariff structures. In areas where the network is already under pressure, the Australian Energy Regulator should require network businesses to implement a tariff structure known as critical peak pricing as an alternative to building new infrastructure.

Under a critical peak price, consumers are told in advance of a pending critical peak period, during which they will be charged between three and eight times the standard flat-rate tariff.³² These

³² Wood, *et al.* (2014)

consumers will pay a lower price at other times. There is evidence this approach can significantly reduce peak demand, with savings for all.³³

An alternative that consumers might find more palatable would be for network businesses to offer critical peak rebates to some customers in areas where the network is constrained. Under this approach, households would be paid to keep their power use below a certain level during times when peak demand is likely to occur.

3.3.3 Introduce cost-reflective feed-in tariffs

When solar PV owners export energy to the grid, they are paid a fixed feed-in tariff that is meant to reflect the average wholesale price of the electricity that is not generated as a result. But cost-reflective pricing for electricity consumed should be balanced with cost-reflective pricing for energy exported. This would further encourage households with solar PV to reduce the strain they place on the network.

One approach would be to have two feed-in tariffs applying at different times. The first would apply for most of the year and reflect the average wholesale price of electricity across this time. The second would be set at a much higher rate, and apply either when wholesale prices are very high, or when the network is under strain.³⁴

At most times, solar households are better off consuming power from their panels rather than exporting. But at peak times, a high feed-in tariff would encourage these households to consume less and export more energy. In response, they may choose to install west-facing panels, since the output is likely to better align with peak periods. This feed-in tariff structure would lower the wholesale price of electricity in the short-term, and take the pressure off the network in the long-term by reducing the need for upgrades.

³³ Faruqui and Sergici (2009), Ito, *et al.* (2015)

³⁴ To be effective at changing behaviour, solar households would need to be informed whenever the higher feed-in tariff is in place.

4 Why battery storage changes everything

The introduction of demand tariffs will not make solar PV economically unviable forever. Its cost is coming down all the time. In a few years further reductions will make it economically viable again, at least in some Australian cities. In this next stage, solar PV for households and businesses can substantially reduce the need for power from traditional, centralised generation and reduce emissions levels at a cost that does not disadvantage other consumers. But the change requires one more element to be complete: the advent of affordable battery storage.

While falling consumption will hurt the wholesale market and returns to generators, its impact on network businesses is likely to be limited, at least for a while. Battery storage has the potential to change that, yet not in the way many anticipate. People will still need the grid and the “death spiral” that many electricity analysts fear is unlikely to occur.³⁵ But use of the grid in new ways will raise profound questions about how the grid should be paid for.

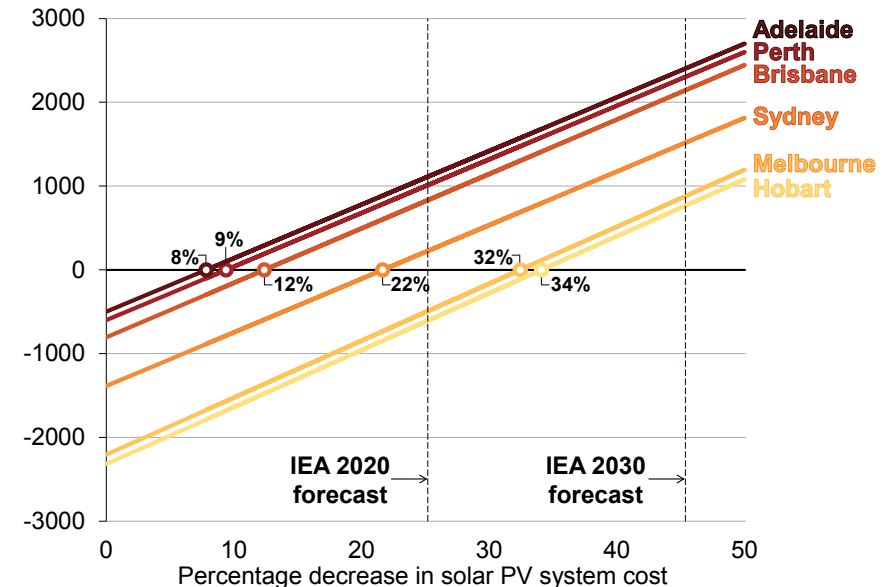
4.1 Further reductions in the costs of installing solar PV will make it economic

Under a demand tariff, a three-kilowatt solar PV system is not economically feasible in the capital cities. But only a small reduction in the cost of solar PV systems is required to make it viable in Adelaide, Perth and Brisbane, as Figure 14 shows.

³⁵ This idea describes what could happen if some consumers decide to disconnect from the grid. The costs are spread across those who remain, which makes leaving the grid more and more attractive until only those with no capacity to leave the grid are left to pay for the lot.

Figure 14: Solar PV only requires a small reduction in cost to break-even in some cities

Net present value of installing a 3 kilowatt solar PV system for a typical household under a demand tariff, \$2015



Note: percentages shown on chart refer to break-even points. Solar PV system cost refers to total installed cost (before SRES subsidy), not a household's out-of-pocket expenses. However, the results assume the SRES remains in place. Source: Grattan analysis of Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012), Solar Choice (2015), Energy Australia (2015), Origin Energy (2015), AGL (2015), IEA (2014).

Such reductions in price could occur very soon. The International Energy Agency forecasts that rooftop solar PV costs could fall by

25 per cent by 2020.³⁶ If that is correct, solar PV will be economically viable by 2020 for households in Adelaide, Perth, Brisbane and Sydney, even after demand tariffs are introduced in 2017. Solar PV costs will need to come down by about a third for it to be economically viable in Melbourne and Hobart, which is forecast to occur before 2030.³⁷

As solar PV prices fall, within a few years more households will choose to adopt solar PV without the need for subsidies. Yet many households will still be unable to. Renters and apartment owners have limited scope to adopt solar PV. For low-income households the upfront costs of solar PV are prohibitive. It is important to unwind cross-subsidies to ensure that these consumers don't end up paying increasingly high costs.

As the cost of solar PV falls, more businesses are likely to install systems. The limited uptake in the commercial sector to date has partly been because the incentives for solar PV have been skewed towards households and not businesses.³⁸ Cost-reflective tariffs were introduced for many businesses some years ago, which reduce the financial attractiveness of solar PV to them. Falling costs will change this. But the cost of solar PV is not the only factor that will affect its uptake in the future.

Given the current trends of falling consumption, the wholesale electricity market is likely to be over-supplied for almost a decade or more, keeping wholesale prices lower.³⁹ The AER's decision in

April 2015 to reduce the regulated returns to network businesses, if upheld, will reduce the delivered price of electricity. In addition, the SRES is due to start winding down from 2017, with no alternative carbon price in sight. These factors will reduce the savings available to solar PV from reducing electricity consumption from the grid.

4.2 Solar PV on its own will not greatly reduce peak demand

Solar PV will continue to reduce demand for electricity generated from centralised sources and delivered through the grid. Yet because use of solar PV does not usually coincide with periods of peak demand, it will not necessarily reduce the size of the grid we need.

Some analysts maintain that solar households would be better off facing their panels west in order to maximise their output during peak times and thereby help to reduce peak demand. But there is a trade-off to doing this, as the solar PV system will produce less power overall, and consumers will have to buy more power from the grid. Whether or not this is cost-effective will vary with individual circumstances and location.

³⁶ IEA (2014)

³⁷ Ibid.

³⁸ AER (2014)

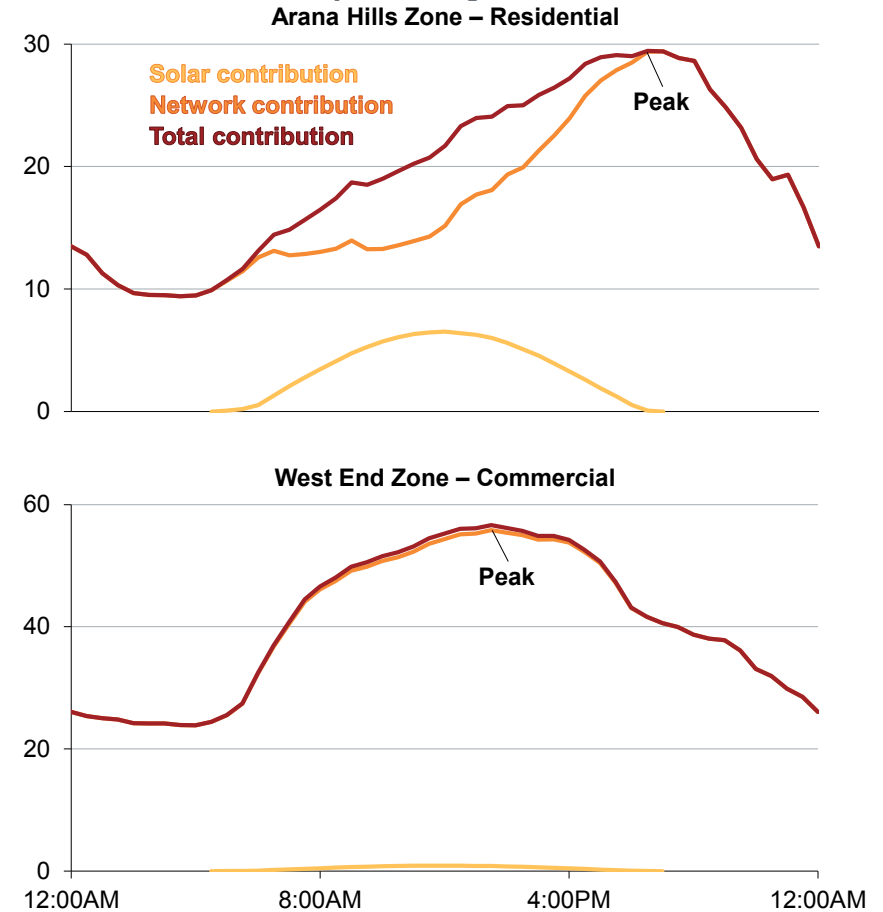
³⁹ AEMO (2014a)

At present, the impact of solar PV on peak demand and network capacity is limited. Figure 15 shows the impact of solar PV on two substations in South-East Queensland. An electricity network is comprised of numerous substations servicing different zones. Substations servicing residential zones typically have a higher prevalence of solar PV than substations in commercial zones. But commercial peaks tend to occur in the middle of the afternoon, while residential peaks occur in the evening.

While the story is not exactly the same for every residential and commercial substation, Figure 15 shows that even a low prevalence of solar PV in a commercial zone can reduce the peak, whereas a high prevalence of solar PV in a residential zone may not reduce the peak at all.

Residential solar forms the bulk of Australia's solar PV capacity. If more solar capacity is used in the way it has always been used, demand will hollow out in the middle of the day, and solar will have little impact on reducing the need for a large grid. The wholesale electricity market will need to cope with the reduction in overall consumption of electricity, but the network will not be significantly affected.

Figure 15: Solar PV output is poorly aligned with residential peaks
Substation load, 15 January 2015, megawatts



Source: Energex (2015)

4.3 Demand tariffs create an incentive for battery storage

All this will change with the introduction of battery technology. The ability to store energy generated at one time for use at a later time will transform the electricity system. Solar PV will interact with centralised generation and the network in a new way. At present, solar PV's ability to compete with centralised forms of generation is limited in two ways: it is not flexible in terms of when it produces energy, and its output is highly variable across days. Energy storage greatly reduces these limitations.

Yet the change will not unfold in the way that many people have predicted. Battery storage has long been cited as the technology breakthrough that will allow customers to end their relationship with the grid.⁴⁰ The combination of solar PV and a home battery has already allowed some households to disconnect from the grid, or to not connect in the first place. These households usually have a back-up source of power such as a diesel generator. But this opportunity is unlikely to be available to urban dwellers. Instead, the introduction of demand tariffs combined with affordable home batteries will offer them a different opportunity to change their relationship with the grid.

A battery can be combined with solar PV to keep a household's maximum demand low, reducing its impact on network peaks. But under current tariffs, the incentives to do this are weak. A demand tariff will encourage households to store some energy in a battery and consume it in peak periods to avoid the high price. The battery can be charged on the grid overnight when electricity is cheaper, or by using excess solar output. By using a battery to

keep their maximum demand low, households with solar PV will still be able to export their excess solar energy.

A household with a three-kilowatt solar PV system already installed will save an additional \$300 to \$400 a year on their electricity bill if they install a seven-kilowatt-hour battery under a demand tariff. This is about \$100 more a year than the same household would save under the current tariff structure.

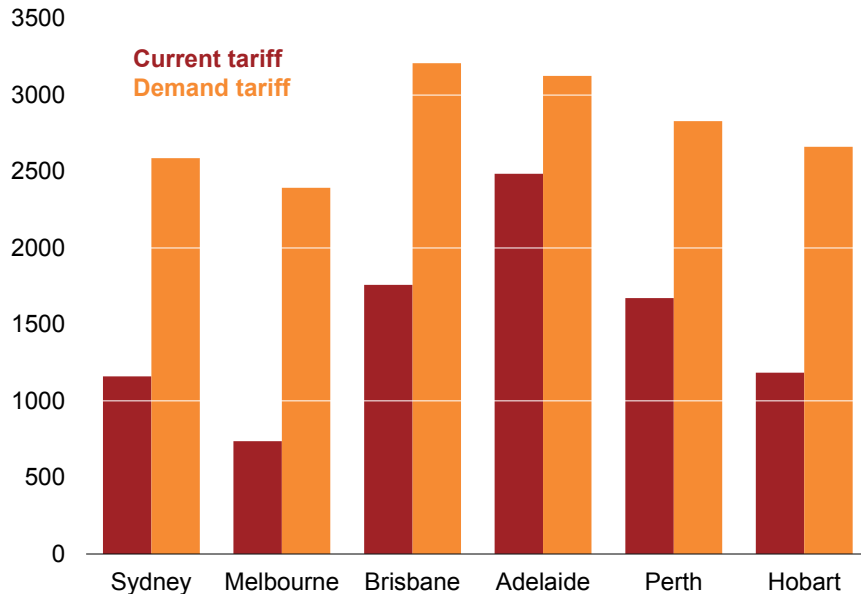
But the news is even better than that. Because a household usually only has a high demand for electricity over a brief period, not every day, batteries would not need to be used as often. Because battery life depends greatly on the number of times it is charged and discharged (and the depth to which it is discharged), a battery used efficiently under a demand tariff could last for up to twice as long as one used daily under the current tariff structure.

Figure 16 considers the price to install a battery at which a household with solar PV will break even for each capital city. Under current tariffs, a seven-kilowatt-hour battery installed for \$2000 is only financially viable in Adelaide, but a price of \$2400 is viable in every city under demand tariffs. In Brisbane and Adelaide, the battery is economically viable at a price of \$3100 under demand tariffs. This assumes that the battery will last for 10 years when charged and discharged daily under current tariffs, but for 15 years when used efficiently under demand tariffs.

⁴⁰ See, for instance, Citi Research (2014)

Figure 16: Battery storage will become economically viable sooner under a demand tariff

Break-even installed price of a seven-kilowatt-hour battery for a typical household with three-kilowatts of solar PV, \$2015



Note: these results assume that households receive the standard feed-in tariff, not a premium feed-in tariff. Results are based on a lithium-ion battery with a depth of discharge of 80 per cent, and an average efficiency of 85 per cent. The battery is used efficiently under a demand tariff to minimise a household's demand. Includes maintenance costs of \$10 per kilowatt hour per year.

Source: Grattan analysis of Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012), Energy Australia (2015), Origin Energy (2015), AGL (2015).

Tesla Motors have announced a home battery, the Tesla Powerwall, likely to be released in Australia in the next couple of years. The seven-kilowatt hour lithium-ion battery to be released in the US is priced at \$US3000 (plus balance-of-system costs

such as the inverter and charger).⁴¹ Accounting for these additional costs, the exchange rate, GST and installation costs, an Australian household would have to pay at least \$7000 to install one of these batteries in 2017 — not an economically viable decision.

Assuming that the cost of installation is about \$1000, battery storage could be economically viable for the average household at a cost of about \$250 a kilowatt hour. Citigroup predicts that a cost of \$US230 a kilowatt hour is possible by 2022 (including balance of system costs), with further price reductions to follow.⁴² These results suggest that tariff reform will be vital to the uptake of battery storage in Australia.

Some households with solar panels will purchase batteries even if the financial costs outweigh the benefits. Some will want to be early adopters of a new technology, others will value the environmental benefits. Some will want to sever their connection with the electricity grid so they can be self-sufficient. But a large-scale rollout of battery storage is unlikely without the technology being financially viable for most households.

There is a further barrier to the take-up of storage. The premium feed-in tariff schemes have years to run, some to as late as 2028. Households that installed solar PV under those schemes will make more money exporting their excess solar energy to the grid than storing it for later consumption.

⁴¹ Tesla Motors (2015)

⁴² Citi Research (2014). At current exchange rates, \$US230 corresponds roughly to \$AU320 once GST is included. A cost of \$AU250 would correspond to about \$US180.

Of course, it is not only households with solar PV installed who may benefit from a home battery. Households without solar may be able to use a small battery to manage their demand. They can charge their battery overnight using cheap electricity from the grid, and use the energy stored to reduce demand during peak times. Under a demand tariff, the decision to install a seven-kilowatt hour battery without solar becomes economically feasible at an installed price of \$2300 in all cities apart from Sydney and Melbourne.

Both solar PV and battery storage can independently save households money on their energy bill. But the two technologies are complementary — households with both will save more. Whether households choose to install one or both technologies will depend on how prices change in the future.

The use of battery storage will reduce peak demand across the network. If a large number of households use a home battery to manage their demand, network businesses will invest less in new and upgraded infrastructure, and all consumers will pay less.

The development of battery storage also gives households the potential to disconnect from the grid. If many do so, other consumers would have to pay more to ensure network businesses get their fixed rate of return. The more consumers have to pay, the more likely they are to leave the network, creating a vicious circle that analysts call the “death spiral” — the end of the network through declining consumer numbers. But a number of factors suggest this danger is not imminent.

4.4 Going off grid is still far off for urban dwellers

Many households are excited about the development of battery storage, believing it will enable them to disconnect from the grid. But without a back-up source of power, a very large financial investment is required to have a reliable off-grid system. Households in urban areas will be much better off using the grid as their back-up source of power instead of a diesel generator.

An off-grid household loses the financial benefit of being able to export electricity to the grid. And because solar output is highly variable it cannot reliably generate all of a household’s power, particularly on winter days of cloud and weak sunlight. This means the battery must be large enough to cover for days of heavy cloud. The size of the required battery and solar PV system is likely to exceed the dimensions of all but the biggest houses.

For example, a seven-kilowatt solar PV system — the minimum size system needed to go off grid and have reliable access to electricity — is likely to require between 60 and 70 square metres of roof space. Ideally the panels would face north and be tilted at about 60 degrees to maximise output in winter, although east- and west-facing roofs can be used if necessary. Many city houses just do not have that amount of clear roof space.

Figure 17 shows that for an upfront cost of about \$34,000 a typical Sydney household that installs a seven-kilowatt solar PV system with 35 kilowatt hours of battery storage (enough backup for two days of consumption) would be able to generate 95 per

cent of its electricity needs across the year.⁴³ That still means the equivalent of 18 days a year with no power.

To attain 99 per cent reliability, a household would require a 10-kilowatt solar PV system and 60 kilowatt hours of storage, at an upfront cost of about \$52,000. This would require even more roof space, ruling out even more households.

Reliability of 99.9 per cent amounts to an average of nine hours a year without power, which would be competitive with the grid in most urban areas. But this would cost a household more than \$72,000 with a 15-kilowatt solar PV system and 85 kilowatt hours of storage — more than double the cost of achieving 95 per cent reliability. For urban residential households, it is not just the cost that would be prohibitive but the size of the system as well. Only the largest homes would be able to accommodate 15 kilowatts of solar panels on their roof space.

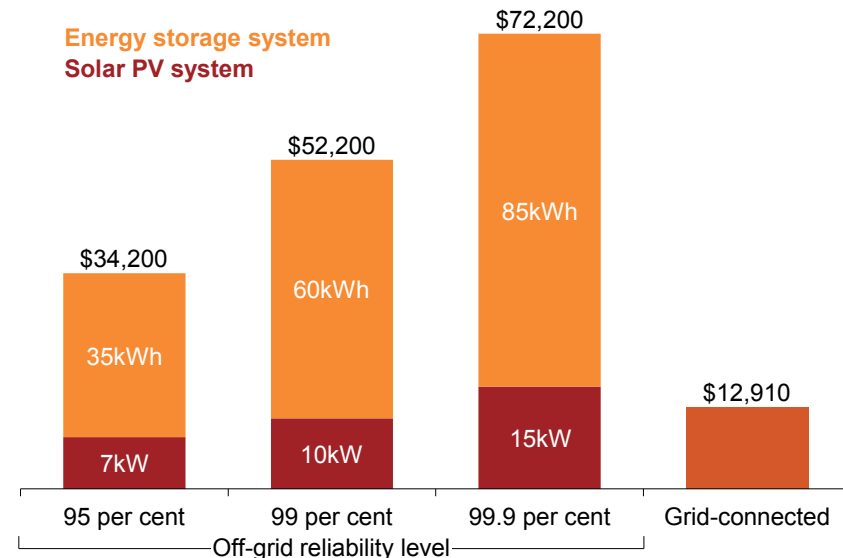
By comparison, the total cost of relying completely on the grid (with no solar or storage) for 10 years is about \$13,000. This is far less than the upfront costs of any of the off-grid options, and is rather more reliable.⁴⁴

⁴³ This is based on a lithium-ion battery price of \$600 per kWh (including balance of system costs), plus \$5000 installation. This reflects where prices might possibly be within the next three years.

⁴⁴ Ten years is chosen as a comparison since lithium-ion batteries are likely to need replacing at this point.

Figure 17: Going off the grid requires a substantial initial investment and reduced reliability

Upfront cost of an off-grid system by reliability level versus net present cost of remaining connected to the grid, typical Sydney household, \$2015



Note: solar PV system is north-facing with a 60 degree tilt and an average efficiency of 80 per cent, lithium-ion battery assumed to run with a depth of discharge of 80 per cent, and an average efficiency of 85 per cent. Maintenance costs of solar PV and batteries are not included. Net present cost of remaining connected to the grid is calculated using a 5 per cent real discount rate over 10 years. Electricity tariffs assumed to rise by one per cent each year, with no carbon price.

Source: Grattan analysis of Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012), Solar Choice (2015), Energy Australia (2015), Origin Energy (2015), AGL (2015).

Some households may accept less reliability than they have from the grid today, but even a few days a year without power can create problems. Food that must be refrigerated or frozen may be spoiled, electric cooktops, ovens and microwaves cannot be used, and there will be difficulties using a home office. Therefore, most households would turn to some form of back-up for the times when the battery is depleted and the sun is not shining.

In remote locations that are not connected to the grid, a diesel fuel generator is the most common back-up source. Generators are a cheaper way to achieve high reliability than installing more solar and storage, but they still require further capital investment and have a high fuel cost. To purchase and run a generator to meet five per cent of a typical Sydney household's consumption may cost more than \$10,000 over a 10-year period, on top of the \$34,000 cost of solar PV and storage. The noise of running a diesel generator would prevent their use in most urban areas. And diesel generators produce a lot of emissions.

In cities, it simply makes sense for households to use the grid as their back-up source. Tariff reform may mean that households are charged more to remain connected to the grid, but much of this cost could be recovered by exporting excess energy. A seven-kilowatt solar PV system might be required to meet a household's consumption in winter, but it produces a lot more energy than a household requires in summer when the days are longer and there is less cloud cover. For a Sydney household with seven kilowatts of solar PV and 35 kilowatt hours of battery storage, the net cost of remaining connected to the grid over 10 years is about

\$2500 — far cheaper than running a diesel generator.⁴⁵ And the battery can be charged from the grid, which may be useful during periods of low sunlight.

4.5 Battery storage will transform the electricity sector

Even without a mass exodus of consumers from the grid, battery storage will have profound consequences for the electricity sector. The take-up of solar PV has already made an impact on both the wholesale market and on networks. The rise of solar PV has been one component in reducing electricity consumption and prices in the wholesale market over the past six years. Reduced amounts of electricity flowing through the grid have driven networks to increase unit prices to maintain revenue.

Under demand tariffs, solar PV will soon become economically viable without subsidies, and further installations will increase the impact on the wholesale market and the network. When battery storage combined with demand tariffs becomes the norm, generators and network businesses will have to adapt to a new world.

4.5.1 Impact on the wholesale market

The large uptake of solar PV is already challenging generators. Even though total generation of rooftop solar is only two per cent of the electricity produced in the NEM, its high output in the middle of the day significantly reduces the demand for electricity

⁴⁵ This is based on a demand tariff with a minimum monthly charge. Under current tariffs in Sydney, this household can actually make a net gain remaining connected to the grid, since export income exceeds the small supply charge.

from centralised generators.⁴⁶ Falling demand and rising renewable generation supported by the RET have already forced a number of coal-fired generators to be mothballed or run only on a seasonal basis.⁴⁷ Further increases in the uptake of solar PV will accelerate such change. More households using solar and battery storage to flatten peak demand will reduce the need for expensive generation in peak periods. But there are implications for baseload generators as well.

At present, the periods of high-priced electricity generation are an important source of revenue for all generators in the NEM. The lower price generators receive during non-peak periods is normally enough to cover the marginal cost of producing electricity from coal or gas-fired baseload generation. The higher price at peak times helps all of them to cover the capital costs of building the generation. Fewer periods of higher prices could force all generators — including those with low or negative marginal costs such as wind farms — to bid at higher prices in order to recover their capital costs.

Yet these changes, significant as they will be, do not appear to pose any policy or regulatory challenges for governments. Some commentators fear that in the long run they could threaten the current structure of the wholesale market.⁴⁸ But many analysts believe the NEM will continue to provide reliable and competitive power, even though some generators may shut down. While industry participants, regulatory agencies and governments will

⁴⁶ AER (2014)

⁴⁷ Ibid.

⁴⁸ Nelson, *et al.* (2014)

need to carefully monitor developments, a catastrophe does not seem to be imminent.

4.5.2 Impact on the electricity network

Grattan's 2014 report, *Fair pricing for power*, proposes the introduction of demand tariffs across the network to ensure customers pay a fair share for the existing grid, and critical peak pricing in areas where there is an imminent need for network investment.⁴⁹

This tariff structure will provide a strong incentive for consumers to reduce peak demand, and solar PV with battery storage could become a cost-effective way for them to do it. The existing network would still need to be paid for, but the high costs of future investment could be reduced or avoided.

Nevertheless, network businesses have big challenges ahead. With a home battery, consumers could be a lot more aggressive in cutting their peak demand. Using a seven kilowatt hour battery, a Brisbane household can cut its average monthly maximum demand of six kilowatts by half, saving more than \$400 a year on its power bill.⁵⁰ If the take-up of battery storage is high, a significant reduction of peak demand could lead to a scenario where some network assets are never required.

If peak demand fell, under current regulations network businesses would be entitled to raise tariffs to maintain their revenue. Rising

⁴⁹ Wood, *et al.* (2014)

⁵⁰ Grattan analysis of Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012). This reduction in a household's maximum monthly demand can be achieved regardless of whether the household has solar PV installed.

prices could also lead to a different kind of death spiral — caused not by households leaving the grid but by households consuming less from it.

Policy makers must face the question of who will pay for the parts of the grid that are not needed. Grattan's 2013 report, *Shock to the system: dealing with falling electricity demand*, identifies the following potential solutions:⁵¹

- Existing infrastructure costs could be frozen and paid for as a fixed annual fee for each home or business, similar to a rates-style system. To prevent the cost of the network being spread over a shrinking number of consumers, all households would have to pay, even those who disconnect from the grid.⁵² Demand tariffs and critical peak pricing would be used to ensure more efficient future investment decisions. The renewable energy industry and some consumers would strongly resist this approach, arguing that it would encourage consumers to stay connected to the grid, while unjustifiably propping up an outdated business model. But it could be justified on the principle that the network was built by the businesses and approved by the AER on behalf of all consumers.

- Using another principle — that network businesses should bear the risk of over-valued assets, as power generators do — the AER could impose asset write downs in its regulatory determinations. Existing regulatory frameworks do not envisage this prospect, and investors in network businesses are unlikely to have factored this risk into their investment decision (although it could be argued that the rate of return they have actually received is sufficient to cover it).⁵³ Such write-downs could be seen as a sovereign risk and deter future investment in Australian infrastructure.
- If neither of the above can be implemented, governments may fund an asset write-down and taxpayers would pay the cost.

None of the alternatives is attractive, but the problem must be addressed. If it is not, consumers will pay for the underutilised assets through ever higher network charges, and consumers without distributed generation will pay more for the old grid than those with solar PV and batteries.

⁵¹ Wood, *et al.* (2013)

⁵² Rates-style systems already deliver a number of services. In Victoria, the Water Act 1989 authorises water businesses to charge landowners for water services if water and sewerage infrastructure is available to their properties, regardless of whether they use those services.

⁵³ Grattan's 2012 report, *Putting the customer back in front*, showed how distributors provided higher equity return with lower risk than other equity investments, rather than lower returns. See Wood, *et al.* (2012)

5 How distributed generation will transform networks

Distributed generation gives networks an opportunity to change the way their business works — to offer services differently and in a more cost effective manner. Opportunities already exist for network businesses to adopt distributed generation instead of adding to the existing grid. This chapter assesses these opportunities and what regulatory barriers must be removed to make them a reality.

5.1 Distributed generation is an alternative to augmenting the network

Traditionally, network services have been delivered to most parts of Australia through substations, poles and wires and other infrastructure. Network businesses have responded to increases in peak demand by augmenting the existing network and investing in new infrastructure.

Distributed generation can offer a low-cost solution to a network constraint — the point at which the network infrastructure cannot cope with demand for electricity. At peak periods, distributed generation can take pressure off the network by supplying electricity directly to the grid, rather than having it flow from a central source through the constrained piece of infrastructure.

Box 3 describes the options that a network business has to deal with a network constraint. Although some forms of distributed

generation, such as diesel generators or batteries, can defer the need for network investment, they may have shorter lives than traditional wires-and-poles solutions. This may actually be an advantage as we enter a period of high uncertainty.

A network can also use distributed generation instead of replacing ageing assets, or as a way to defer their replacement by alleviating the load on the local network.

Some network businesses already use distributed generation as an alternative to traditional network investment. Some embed diesel or gas generators within their networks or use solar or wind generation in more remote areas. Box 4 provides an example of how a network business uses distributed generation to deal with a constraint on the grid.

Box 3: Options for dealing with network constraints

The introduction of more cost-reflective pricing will help to alleviate pressure on the network. Grattan's 2014 report *Fair pricing for power*, argues that network businesses should consider critical peak pricing as a way to deal with a network constraint. This pricing will encourage consumers to reduce their demand at peak times, reducing the constraint on networks. The network businesses have three other options to address constraints. These can work either in conjunction with critical peak pricing or where it has not been introduced:

1. Traditional network build: the business increases the capacity of the existing network by enhancing the infrastructure. This may involve either adding infrastructure such as a new line, or increasing the capacity of existing infrastructure — by replacing an existing substation, for example. When peak demand and total consumption in the local area are likely to continue growing, these options are likely to be the most cost-effective solution.
2. Demand management: instead of increasing the network's capacity, a network business acts to decrease demand during peak periods. It might pay customers to reduce their electricity use during peak periods, for example. For short periods, this is the most cost-effective means of dealing with a constraint.

In the PeakSmart air-conditioning scheme run by Energex in south east Queensland, customers are paid an upfront fee of up to \$500 to connect their air-conditioner to the scheme. During peak periods, Energex is able to remotely limit the amount of electricity used by the air-conditioners, reducing stress on the network. By the end of March 2015, more than 26,000 air-conditioners in south east Queensland had been connected to the scheme. As part of Energex's broader demand management programme, the PeakSmart program has contributed to a reduction of 144 megawatts of electricity demand over a five year period.

3. Distributed generation solution: a network business can bypass the constraint by local installation of a diesel or gas-fired generator. The network business can either own the generator themselves, or contract an independent company to provide the distributed generation solution.

During a peak period, the generator provides electricity to the area. In the future, batteries may prove to be a cost-effective option. Electricity could be stored at times of low demand and supplied to the local area when needed during peak periods.

Box 4: Traralgon case study

In 2012, AusNet Services investigated a forecast constraint at its zone substation in Traralgon, Victoria, which supplies more than 16,000 customers in central Gippsland. Increases in peak demand put pressure on the three transformers at the substation, potentially leading to a loss of power for some households in Traralgon and surrounding areas.

A typical network response to this constraint would be to replace and upgrade two of the transformers at the substation. Instead, AusNet Services replaced just one transformer and commissioned a third party, NovaPower, to supply up to 10 megawatts of power from its Traralgon Power Station, situated downstream from the substation, at times when the network is constrained.

The \$11million, 10 megawatt gas-fired power station operates as an independent generator, selling electricity into the NEM. The contract with AusNet Services guarantees that the power station will fire-up during the periods of the constraint reducing pressure on the substation.

This reduces the risk of power outages for local consumers and deferred the need to spend \$2.9 million on upgrading a second transformer at the substation.

Yet these types of example remain the exception. Current regulations do not consistently provide incentives to deliver the most cost-effective outcome.

5.2 Why networks are not using distributed generation

The main regulatory tool the AER has at its disposal to encourage network businesses to use distributed generation are the Regulatory Investment Tests for transmission and distribution (RIT-T and RIT-D). The tests require network businesses to consider non-network solutions (as in Box 3) as an alternative to investment in poles and wires.

This chapter examines the RIT-D process and the incentives and barriers that exist to assist or prevent distribution businesses from using distributed generation. For transmission businesses, the size of upgrades limits the use of non-network solutions, although distributed generation can still play a role.

When a distribution business identifies a need to enhance the capacity of the network and the cost exceeds \$5 million, it is required to undertake a RIT-D assessment.⁵⁴ Third parties may be invited to submit proposals to deliver a non-network solution. If the solution is technically viable and offers the greatest economic benefit, then the distribution business must adopt it.

At present, network businesses use surprisingly little distributed generation, even with the RIT-D process.

⁵⁴ In Western Australia, distribution businesses are required to undertake the Regulatory Test, which is their version of the RIT-D. However, the Regulatory Test only applies to any proposed augmentation that costs at least \$11.7 million.

The 11 distribution businesses in the NEM have identified only 37 projects as suitable for the RIT-D process over the next five years. Some of these depend on new housing developments or other demand growth, while others may not pass the RIT-D test.

Part of the reason for the small number of potential projects may lie in limitations with the RIT-D. We examine these here:

5.2.1 There are no specific enforcement provisions

The rules governing the RIT-D process may not be sufficient to force distribution businesses to consider non-network options. Initially the COAG Energy Council proposed that the AER would have specific review and audit powers to determine whether (a) network businesses were adequately considering non-network options and (b) were considering all projects above the \$5 million threshold. These provisions were not adopted because in its final ruling the AEMC decided that the AER's existing powers were adequate.⁵⁵

As a result, while all businesses are required to undertake a RIT-D in the above circumstances, there is no process beyond the existing compliance regime to ensure that it happens. The RIT-D replaced the old regulatory test at the beginning of 2014 and how much the AER is able to ensure compliance with these regulations is yet to be determined. If, over the next regulatory period, it becomes apparent that network businesses are not adhering to the RIT-D process, the COAG Energy Council should consider the introduction of the specific review and audit powers that it initially proposed.

⁵⁵ AEMC (2012)

5.2.2 The investment test does not apply to replacement spending

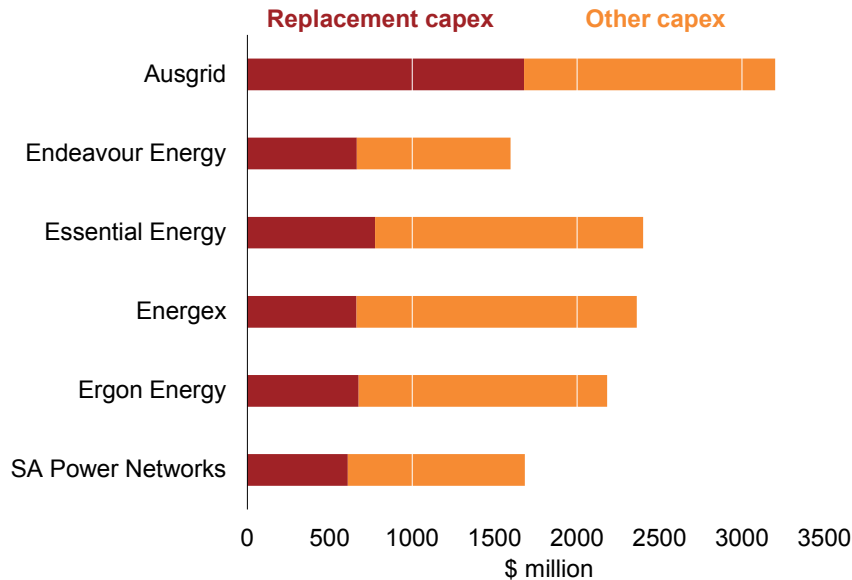
The RIT-D process only applies to projects that augment the network and not to the replacement of existing infrastructure, unless that replacement adds capacity to the grid.

Yet the investments network businesses make to replace existing assets are a significant part of their capital expenditure. On the basis of current AER revenue determinations, network businesses in New South Wales, Queensland and South Australia are forecast to spend about 37 per cent of their capital on replacing assets, as shown in Figure 18.

As the cost of distributed generation reduces and battery storage and other technologies develop, these non-network solutions are increasingly likely to be a cost-effective alternative to replacement spend.

Figure 18: Replacing existing infrastructure forms a large part of capital expenditure

Replacement capital expenditure relative to total capital expenditure



Note: The information reflects the final AER decisions relating to Ausgrid, Endeavour and Essential, and the AER's preliminary decisions regarding Energex, Ergon and SA Power Networks.

Source: Grattan analysis of AER (2015a), AER (2015b), AER (2015e), AER (2015c), AER (2015d), AER (2015f).

Given the amount spent on it, and the increasing potential of distributed generation, the RIT-D test should be imposed on replacement expenditure. The AER have recently identified this

gap and have suggested that the AEMC consider applying the RIT-D (and RIT-T) to replacement spend.⁵⁶

5.2.3 Networks are still encouraged to spend on infrastructure

The regulatory process has flaws that continue to encourage distribution businesses to over-invest in the network.⁵⁷ Grattan's 2012 report, *Putting the customer back in front*, shows that the more a business invests in capital expenditure, the greater the return.

Every five years the AER determines a network business's total revenue for the next five-year period. It also determines the network business's rate of return — the yearly return it gets on the amount of money it has invested in its infrastructure.

The rate of return that a network business receives has been keenly debated in recent years. If it is too high, as many independent analysts believe, it provides a strong incentive to network businesses to build infrastructure of questionable need.⁵⁸ New South Wales network businesses were allowed a rate of return of over 10 per cent in the previous regulatory determination, and spent the money on major capital investments. The businesses are not solely to blame: unduly high reliability standards imposed by the New South Wales Government forced them to spend significantly on capital.

⁵⁶ AER (2015g)

⁵⁷ Wood, *et al.* (2012)

⁵⁸ Mountain (2015)

Since 2012 and the release of *Putting the customer back in front*, the regulatory framework that governs distribution businesses has changed significantly. The AER's Better Regulation reform program has improved the incentive for network businesses to save on their capital expenditure. For any saving on capital expenditure during the five-year regulatory determination, the business gets to keep 30 per cent of that saving.

The outcomes of the last round of regulatory determinations also suggest that the AER is addressing the problem. Capital spending for all New South Wales network businesses that have been assessed has been downgraded by about 20 per cent on average. The rate of return has also been reduced from about 10 to 7 per cent.

These changes are encouraging. The incentive for businesses to gold plate the network is much reduced. Yet the overall regulation process may still encourage businesses to favour building new infrastructure over lower-cost alternatives. Whether the recent changes to the regulatory framework and the actions of the AER will be enough to counteract this remains to be seen.

5.3 The regulatory framework needs to change

Providing network businesses with the right incentives to deliver the lowest cost options is difficult. Consumers expect networks to be safe and deliver electricity when they need it, but they also want it done at least cost and do not want to pay for infrastructure they do not need.

Recent changes have done much to reduce the incentives for network businesses to over-invest in network infrastructure. Two

adjustments to the regulatory framework will improve this further and should reduce the likelihood of future over-investment.

5.3.1 Annual adjustments of consumption forecasts

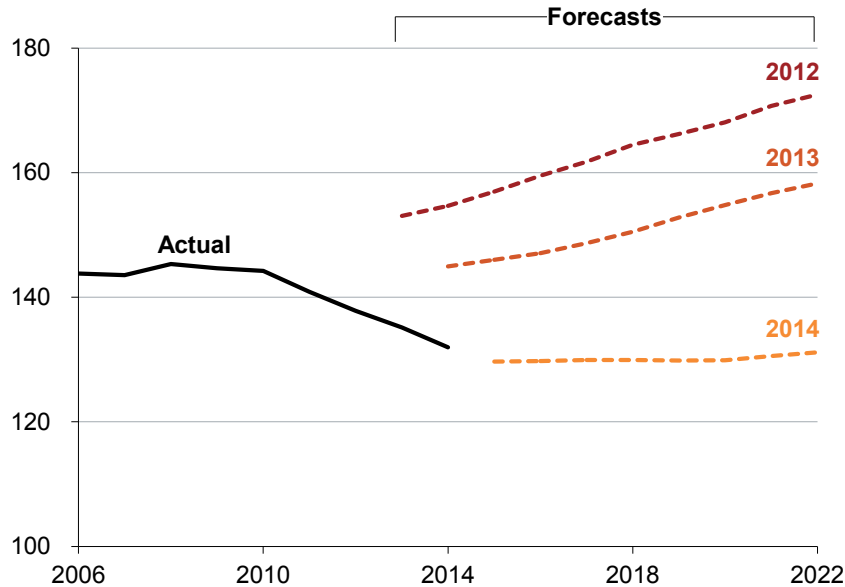
The level of capital spending is determined at the beginning of the regulatory period and is set for a five-year period. A network business's proposed capital expenditure will depend on forecasts for electricity consumption and peak demand over the future period. As shown in Figure 19, over the last 10 years, these forecasts have become increasingly inaccurate and usually too high. This led to regular downward adjustments.

The current regulatory model includes some incentive for the network business not to proceed with unnecessary capital expenditure. If the business chooses not to spend capital included in the original forecast, it still collects revenue as though the investment had been made. But this is allowed only for the five year regulatory period and at a reduced level into the next five-year period.

Despite this approach, the business still has a strong incentive to argue for excessively high capital forecasts. There is a better way.

Setting capital expenditure based on the best available five-year forecast but then reviewing it annually would allow capital spending to reflect the most up-to-date forecasts, such as those published by the Australian Electricity Market Operator (AEMO). Revenue requirements and network prices would then be adjusted according to the new forecast level of spending.

Figure 19: Consumption forecasts can adjust substantially in a year
National Electricity Market residential and commercial energy consumption, forecast versus actual, terawatt hours



Note: one terawatt hour is equal to one billion kilowatt hours.
Source: AEMO (2013), AEMO (2014b)

Network businesses may complain about the increased administrative burden, yet the businesses already produce yearly electricity demand forecasts in order to complete their annual planning reports. Businesses operating in competitive markets routinely use a similar process in their internal capital management processes.

5.3.2 Formalise asset write-downs in the regulatory framework

At present, the AER can undertake a limited review of capital spending when a network business spends more than the AER has approved for a five-year period. If the AER finds that the capital spending was not prudent, it can prevent the business from recovering the cost of some of their infrastructure through the network charges. The AER reviews the prudence of the capital spend as a whole, yet only capital expenditure that exceeds the allowance can be excluded from the Regulated Asset Base (RAB).

This is a new rule and has yet to be tested. But it should be extended to allowing the exclusion of any capital expenditure the AER deems not to be prudent, not just the value of the excess expenditure. Such a change would effectively embed a process for future asset write-downs in the five-year regulatory process.

As part of the determination, network businesses should be asked explicitly to demonstrate prudent capital expenditure during the previous five-year period. The AER will need to form a view on whether this spending has been prudent. If it has, it can be rolled into the asset base. If it hasn't — either because infrastructure has been built where there is no need or because a business has implemented one solution where a more cost effective, non-network one was available — the AER should have the authority to reduce the base. Such post-expenditure capital expenditure reviews are a common practice in competitive markets.

Western Australia's New Facilities Investment Test (NFIT) operates in a similar fashion. The NFIT determines the extent to

which capital spent on major augmentations can be recovered through network tariffs. The Economic Regulation Authority can exclude from the RAB any investment that does not satisfy the test. A result of Western Power's first Access Arrangement (Western Australia's version of a regulatory determination), was the write-down of around \$220 million worth of assets as a result of the NFIT.

This approach increases the financial risk to the network business, bringing it close to that faced by a non-regulated business. The rate of return to the network business may need to be adjusted to reflect this risk.

These changes may still not get the incentives absolutely right; however, they will be a move in the right direction. For example, the threat of an asset write-down may be sufficient to encourage the businesses to spend more prudently.

6 Where going off-grid makes sense

The emergence of distributed generation challenges the 100 year-old model of the grid as a natural monopoly. Genuine competition in how network services are provided is in sight. Although going off-grid is still not economically viable in cities and may not be for a very long time (see Chapter 4), it does make sense for some households and communities, and the numbers of these will steadily increase.

At present, there are powerful barriers to going off-grid. Under current regulations, network businesses struggle to offer off-grid solutions and there is no process to allow third parties to compete to deliver these services. Policy makers need to address these problems now to ensure that solutions exist when going off the grid becomes the most economically efficient way to access electricity.

6.1 Going off-grid in remote areas can make sense

In some rural and remote areas, an off-grid, distributed generation solution makes sense today. Box 5 describes an example and highlights the opportunity and challenge to delivering such a solution.

Box 5: Case study: Gascoyne Junction, Western Australia

Horizon Power is a government-owned, vertically integrated electricity supplier to 45,000 consumers in 45 communities in regional and remote Western Australia. Gascoyne Junction is a town of 44 households approximately 175km from Carnarvon.

Electricity is produced by four 80 kilowatt diesel generators owned by an independent company that has a supply contract with Horizon Power. Horizon buys electricity and sells it to the houses via a local network at a flat rate of 22 cents per kilowatt hour. The revenue from this tariff does not cover the cost of supply, and another government-owned business, Western Power, pays Horizon Power a subsidy to cover the gap. Effectively urban consumers pay the subsidy for regional and remote consumers.

In Gascoyne Junction, three houses have installed five kilowatts each of solar PV, contributing to meet a demand that averages around 90 kilowatts, with a summer peak of 250 kilowatts.

It is likely that some combination of more solar PV, either on roofs or as a small solar farm could be combined with battery storage and a much smaller diesel generator as a cheaper solution in the future. A decision point could be on expiry of the current contract with the generator.

The critical regulatory question is whether the current policy and regulations will allow Horizon Power to implement such a lowest cost solution. The fact that Horizon Power is an integrated supplier makes things simpler, but the combination of a low, fixed tariff and a subsidy do not necessarily provide an incentive for the lowest cost solution.

6.1.1 ...for customers who are not connected to the network

The population density of urban areas keeps network costs relatively low. The cost of connecting an additional household to the grid may be only the cost of running a wire to the property, probably a few hundred dollars.

But because remote areas may not have a nearby network, connecting to the nearest grid will require investment in new network infrastructure, which consumers must wholly or partly pay for. The amount they will contribute will depend on the nature of the network upgrade.

There are two types of costs networks face when connecting a new customer to the grid in remote areas. The first is the physical cost of connecting the property to the network and may involve investment in new poles and wires (shallow augmentation). The second is the cost of any upgrade to the network, such as an upgrade to a substation, necessary to support the addition of a further property (deep augmentation). A customer connecting to the grid will be expected to pay the network business the full cost of any shallow augmentation, but not the deep augmentation costs, which are paid for by the network business's broader customer base.

Where shallow augmentation costs are the only costs the network faces in order to connect the customer, the decision to go off-grid rests mainly with the consumer as they have a choice either to pay for the grid connection, or to buy an off-grid solution. Alternatively, the network may require deep augmentation to connect a customer. In this case, the customer wishing to connect their property to the network does not face the full cost of

connection. The result is that they may choose to connect to the grid, when from an economic perspective it would have been cheaper to have them choose an off-grid solution. The extent to which the decisions made by individual customers deliver the most cost-effective solution is not straightforward, as illustrated in Box 6.

Much will depend on whether further growth on the network is likely. If the network business anticipates that more customers will connect to the local network in the future, it should either undertake the deep network augmentation, or implement a non-network solution — whichever is lowest cost when anticipated growth is included. If such growth is not expected, the network businesses should be able to offer the customer a distributed generation solution. Yet ring-fencing arrangements in the regulations, explained later in this section, which prevent network businesses from operating as anything other than a network business, can be a barrier to this alternative.

Box 6: Off-grid scenarios in remote areas can be complex

Customers in remote areas are, in many cases, supplied through Single Wire Earth Return (SWER) lines. There are about 28,000 kilometres of SWER lines in Victoria and 65,000 in regional Queensland.⁵⁹ The cost of these SWER lines is estimated to be \$50,500 per kilometre.⁶⁰

Imagine a customer who wants to connect a new property to the nearest network supply point, two kilometres away. If only the cost of the line is taken into account, the cost of connection is \$101,000 for a line with a typical life of 30 years. The cost of providing an off-grid solution, featuring solar panels, a battery and back-up generator for that period is \$80,000, including maintenance and replacement costs.

The cost-effective solution for the customer would be to install distributed generation. Yet if another customer builds a property next to the first customer and makes the same decision, together they would have spent \$160,000 to go off-grid, well in excess of the network solution.

If both customers had built their properties at the same time, or the network business had foreseen the arrival of the second customer, the cheaper network solution would have gone ahead. There is no perfect solution to these challenges, so balanced judgement and flexibility will be necessary.

⁵⁹ Nous Group (2010)

⁶⁰ Dyer (2009). Prices have been adjusted for inflation.

6.1.2 ...for consumers who are already connected to the network

There is a high cost per consumer to build, maintain and operate the network in remote and regional areas. These are the first consumers for whom leaving the grid will be financially favourable as distributed generation costs fall. Yet because urban consumers subsidise the connection costs of regional and remote consumers, the latter groups will not face the price signals that will encourage them to make the lowest-cost decision.

Spreading the cost of grid connection for people in rural and remote areas across the whole community has been a political choice to avoid being seen to disadvantage people in regional and remote Australia. Under Queensland's Uniform Tariff Policy, for example, retail electricity prices in regional areas reflect the costs of supplying similar customers in the south east of the state, even though actual supply costs are higher in regional areas. A state government subsidy covers the extra costs incurred by the network business, Ergon Energy.

Consumers can only make the most cost-effective decision between a network and distributed generation solution when faced with the real cost of the alternatives. This is not the case under a policy like the Uniform Tariff Policy. Yet, removing these locational subsidies is likely to be politically difficult.

The practical solution is probably to recognise that only the local network business can make a reasonable assessment of the best alternative. The challenge is to ensure that any government subsidy does not prevent delivery of lowest-cost solutions.

6.1.3 ...for edge-of-grid communities

In some cases the cost of connecting a community to the grid or maintaining that grid connection is far greater than creating an islanded network. An islanded network has its own generation and network that operates independently from the rest of the grid or maintains a thin connection to it.

Such a network is most likely to be relevant to communities on the fringe of the grid. Some will be in remote areas, others will be semi-urban. New developments at the fringes of cities and towns and without existing grid connection may also benefit from an islanded network.

Yet maintaining a connection to the main grid has benefits. Firstly the main grid can act as a back-up to the islanded network. In extreme situations, where generation cannot meet demand, the community could purchase electricity from the main grid, using it as if it were a back-up generator. Conversely, any excess electricity the islanded network generates can be sold into the main grid.

Anecdotal evidence suggests there are already areas where high costs to maintain the main grid would make an islanded network appropriate. If faced with the decision to connect these communities or individuals to the main grid now, distributed generation would be a cost-effective alternative, as Box 7 shows.

There will be more of these opportunities as distributed generation costs fall and the technology improves.

Box 7: When disconnecting makes sense

In the north west of New South Wales, 263 customers are serviced by more than 1800 kilometres of network line: almost seven kilometres of line per customer. Even if these lines were the only infrastructure that had to be built to supply electricity to these customers — and there are other costs — the cost would be \$91 million, or more than \$346,000 per customer.⁶¹

Instead, it would be cheaper for the network to provide each with a distributed generation option. The cost over the same period would be about \$80,000 per customer. When the network needs to be replaced, this will most likely be the best option. Ensuring that network businesses adopt the RIT-D process for replacement capital spend will require the businesses to consider distributed generation for scenarios such as this.

In order to deliver an islanded network under the current structure, a set of complex commercial arrangements is required between generation, retail and network businesses to capture the benefits. But there is little incentive for these businesses to do so. The alternative is an integrated approach with a single organisation responsible for generation, networks and retail — in other words, a return to the old model of electricity supply.

⁶¹ Ibid. Prices have been adjusted for inflation.

6.2 Back to the future: recreating a traditional power company?

Islanded networks create an opportunity to provide competition in the delivery of the whole electricity service, from generator to user. While network businesses are in a good position to deliver these services, regulations permitting, they are by no means the only option. Another business or third party could offer to supply these services to the consumer or community.

Yet there are barriers to providing competition among alternatives in these circumstances. This section focuses on three issues: the current ring-fencing arrangements, a process to introduce competition and how electricity from the existing grid should be paid for. Other issues include whether consumer protections should stay the same in an islanded network. Governments, network businesses and other stakeholders need to consider these questions now, before islanded networks become viable but cannot be introduced because of poor incentives or regulations.

6.2.1 Ring-fencing arrangements

Network businesses will be well placed to provide islanded networks when they are the best solution. Yet both national and state regulations have ring-fencing arrangements that restrict the activities these businesses can undertake. They make innovations such as islanded networks difficult, and should be reformed.

In South Australia, a distribution business cannot also hold a retail or a generation licence, unless the generation is used to support the network by dealing with a network constraint (see Chapter 5). Similar provisions exist in other states. In Victoria, networks are

limited to installing generation with a capacity of up to 30 megawatts to provide network support.

Western Power, the government-owned network business that covers Perth and the south-west of Western Australia, has the same constraint. Western Power wants to undertake a trial to assess whether, when an islanded network opportunity exists within its network. As Western Power is prevented from delivering such a solution, it is investigating whether the islanded network could be supplied by Horizon Power, also government-owned, but without the same licence constraints. This is because Horizon Power is an integrated supplier in order to supply electricity to its consumers in regional and remote areas of the state.

These regulations can also hinder networks from maximising the value of distributed generation. Because they are prevented from trading in the NEM, they cannot sell electricity from distributed generation on the spot market. As an alternative, the distribution business can make a commercial arrangement with a retailer to purchase the electricity from them, but the network will not get the most value from this arrangement.

If a network business was allowed to trade in the NEM, a network business using a generator or battery could sell electricity on the wholesale spot market during periods when prices are high, generating a revenue stream from its distributed generation. Increased revenue will make the business case for distributed generation more attractive.

At present, a network business could set up its own ring-fenced business away from its other operations to generate, buy and sell electricity in the NEM. Yet this will create an additional cost and

administrative burden on a network business to deliver a solution that is supposed to save money, and network businesses may choose not to go down this path.

It is expected that the AER will be required to develop and publish ring-fencing guidelines by July 2016. As part of this process the AER should review current ring-fencing arrangements to determine whether they present barriers to these alternatives. If they do, the rules should be changed to remove the barriers.

6.2.2 Competition in delivery of islanded networks

At present, consumers in remote communities have limited options for electricity supply. Distributed generation will give them a genuine alternative to grid-supplied electricity. Competition can make sure the solution is delivered at least cost.

The size of an islanded network creates little scope for competition for either generation or retail services. Because a community's needs would require only a limited number of generators, which would need to be in place at the time an islanded network was created, the opportunity for entry into the market would be limited.

Retail competition would also be difficult. Costs for the islanded network would be isolated and it is unlikely that different prices could be charged to customers within the network. The lack of competition may also lead to customers facing higher prices than they otherwise would.

A solution would be to allow any business to tender for the right to provide a fully integrated system of generation, network and retail

services for a fixed term. The tender would have to determine the customers' electricity price to prevent the franchise owner exerting monopoly power.

Policy makers have much to resolve. Which communities are appropriate for an islanded network? Who should run the tender? How can consumer protections in an islanded network be maintained? Governments should initiate a process to consider how a competitive tender would work.

6.2.3 Paying for the existing grid

Islanded networks that wish to retain a shallow connection to the main grid to back up their islanded generation will still need to contribute to the main grid. Although they may use the main grid rarely or not at all, the connection will need to either be built or maintained.

Prices for connection to the main grid need to be carefully considered. Consumers in the islanded network should not be required to pay for more network services than they use. At the same time, consumers on the main grid should not cross-subsidise the islanded network's connection.

The introduction of a rates-based system, set out in Chapter 4, to pay for the main grid regardless of use would help to alleviate the problem. Consumers in the islanded network would pay a flat, yearly rate for the main grid infrastructure.

If the islanded network needed to purchase electricity in an emergency, it should carry a premium price to allow for the islanded network's lack of contribution to the costs of running the

main grid. Alternatively, the islanded network could pay a higher fixed rate to contribute to the running of the main grid, reducing the risk of price shocks should it ever need to access electricity from the main grid.

Governments, regulators and industry participants need to start thinking about how to put the right processes in place now. Without them there is the risk that consumers will pay more for their electricity services than they need to. Alternatively, they will take matters into their hands and leave the network before governments and network businesses act. This would leave network businesses struggling to recover the costs of the existing grid — the real death spiral.

7 What governments should do

Governments' support for the development of solar PV technology was poorly considered and implemented. With advances in battery technology, governments will again face the challenges of distributed generation. This chapter summarises recommendations that will help distributed generation contribute to a fairer, cheaper and low-emissions electricity sector.

7.1 Get pricing right

A clear timetable, no later than 2020, should be set for the mandatory introduction of demand-based tariffs across Australia. A roll-out of advanced meters — either smart or interval meters — to all consumers will need to be completed by the time demand-based tariffs become mandatory.

Other changes to the pricing structure, including critical peak pricing and more cost-reflective feed-in tariffs, should also be introduced. They will provide consumers with more targeted price signals in places and at times when the network is under stress. Responses to these signals by all consumers, but particularly those with distributed generation, can help prevent increased spending on network infrastructure.

7.2 Develop an approach to dealing with redundant assets

It is likely that developments in distributed generation and storage will result in under-utilisation of existing electricity network assets. In conjunction with all stakeholders, governments need to develop an answer to how these assets should be addressed, including who should pay for redundant assets and under what arrangements.

7.3 Get the right network regulations in place

Changes need to be made to the regulations to ensure network businesses deliver the lowest-cost solutions in all circumstances.

Require network business to undertake an investment test for all replacement spending over \$5 million

Network businesses are having to spend more to replace infrastructure, yet they are not required to consider non-network alternatives. Adopting the RIT-D investment test for replacement spending will encourage networks to take up distributed generation solutions.

Introduce annual adjustments of consumption and peak demand forecasts

Forecasts of electricity consumption and peak demand determine how much capital network businesses invest in. These forecasts have been highly unreliable in recent years. To prevent this, the AER should be required to work with the businesses to adjust

forward capital plans on a yearly basis based on up-to-date forecasts.

Formalise asset write-downs in the regulatory framework

The regulations should allow the AER to disallow any infrastructure spending from the RAB by the amount of all capital spending that fails a prudent-investment test.

7.4 Remove barriers to delivering off-grid solutions

A range of barriers needs to be overcome for this future to be realised. There is as yet no formal competitive process by which a community can become an islanded network. Ring-fencing arrangements prevent network businesses from providing combined generation and network services. How an islanded network would pay for its connection to the grid, and how consumers in an islanded network would maintain their consumer protections, are difficult questions. Policy makers need to start work to answer them.

In the first instance the AER should review the ring-fencing arrangements to determine the extent to which they will act as a barrier to adoption of distributed generation. Governments should develop a competitive tender process in the delivery of an islanded network.

7.5 Conclusion: here comes the sun

Battery storage is coming. Society has paid more for solar PV than it should have. We should not make the same mistake with battery storage. Nor should it be prevented from forming an integral part of our electricity system.

In the past, policy makers failed to properly address the challenges of distributed generation. Early adopters of solar PV understandably took advantage of the policy failure. But all consumers paid a high price. The rise of battery storage presents a new challenge. If we get it right this time, solar power in Australia will finally find its place in the sun.

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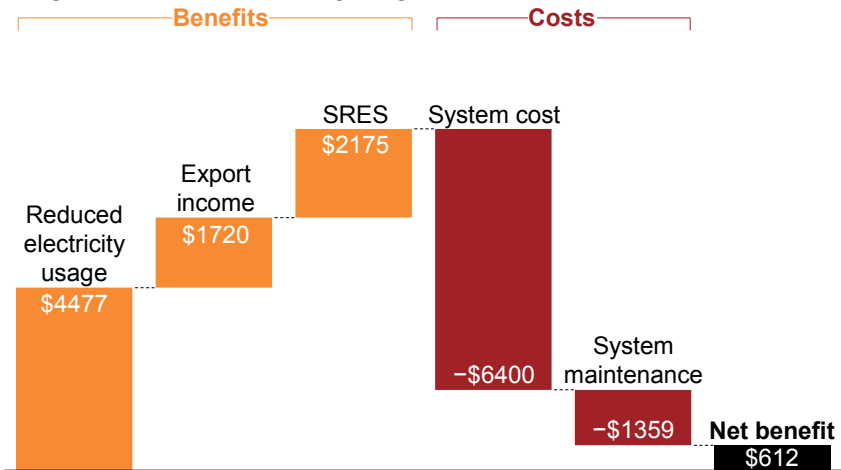
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Appendix A Economics of solar PV, extended results

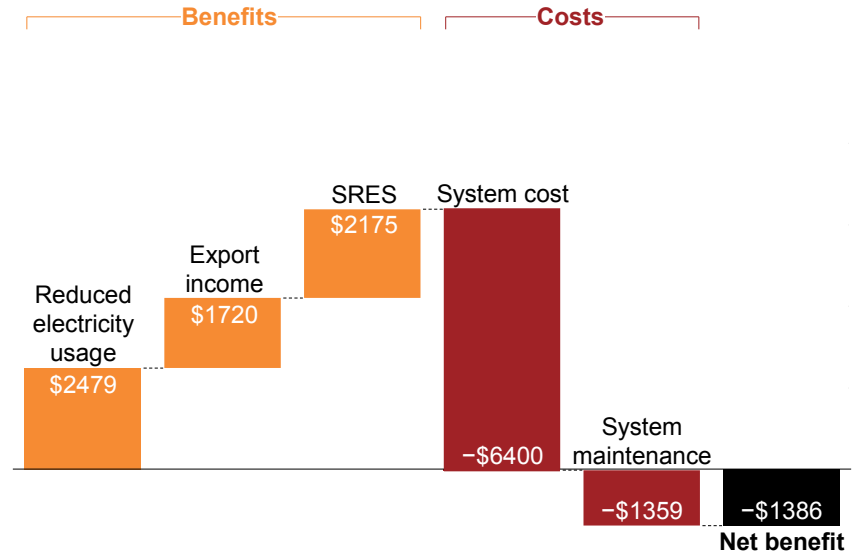
Sydney

Figure 20: Net present benefits and costs of a three-kilowatt solar PV system, current tariff, Sydney



Source: Grattan analysis of Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012), Solar Choice (2015), Energy Australia (2015), Origin Energy (2015), AGL (2015).

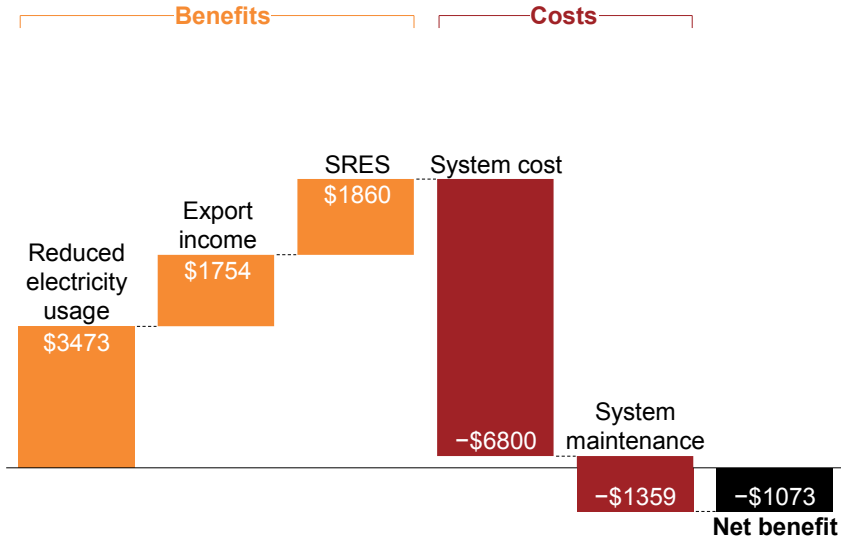
Figure 21: Net present benefits and costs of a three-kilowatt solar PV system, demand tariff, Sydney



Source: Grattan analysis of Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012), Solar Choice (2015), Energy Australia (2015), Origin Energy (2015), AGL (2015).

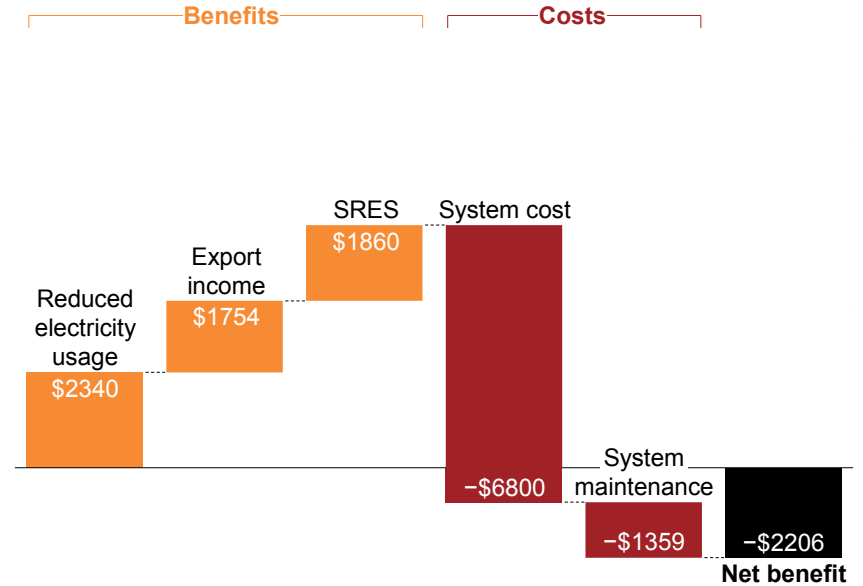
Melbourne

Figure 22: Net present benefits and costs of a three-kilowatt solar PV system, current tariff, Melbourne



Source: Grattan analysis of Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012), Solar Choice (2015), Energy Australia (2015), Origin Energy (2015), AGL (2015).

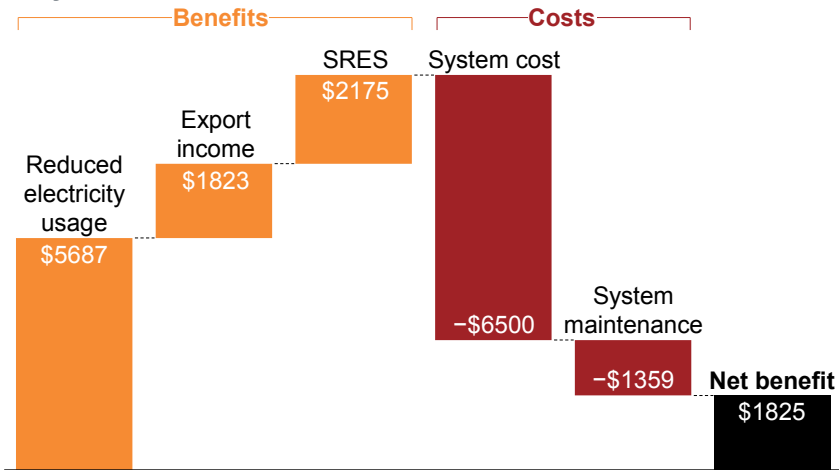
Figure 23: Net present benefits and costs of a three-kilowatt solar PV system, demand tariff, Melbourne



Source: Grattan analysis of Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012), Solar Choice (2015), Energy Australia (2015), Origin Energy (2015), AGL (2015).

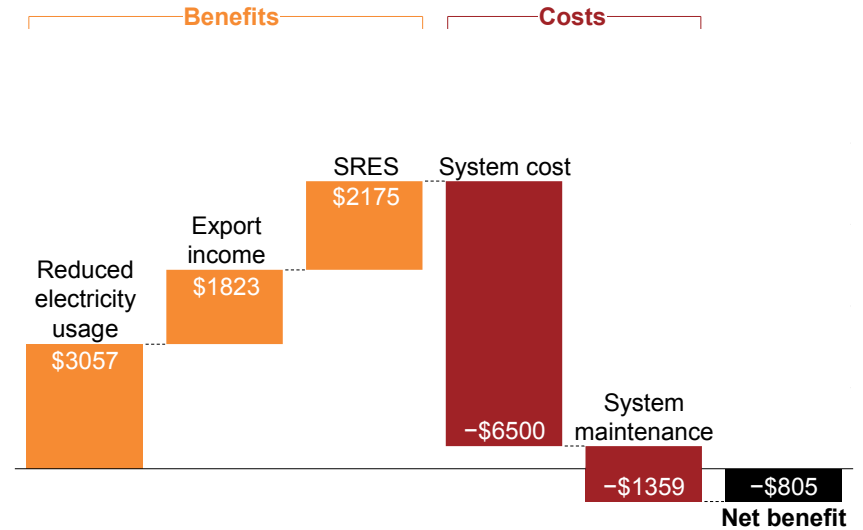
Brisbane

Figure 24: Net present benefits and costs of a three-kilowatt solar PV system, current tariff, Brisbane



Source: Grattan analysis of Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012), Solar Choice (2015), Energy Australia (2015), Origin Energy (2015), AGL (2015).

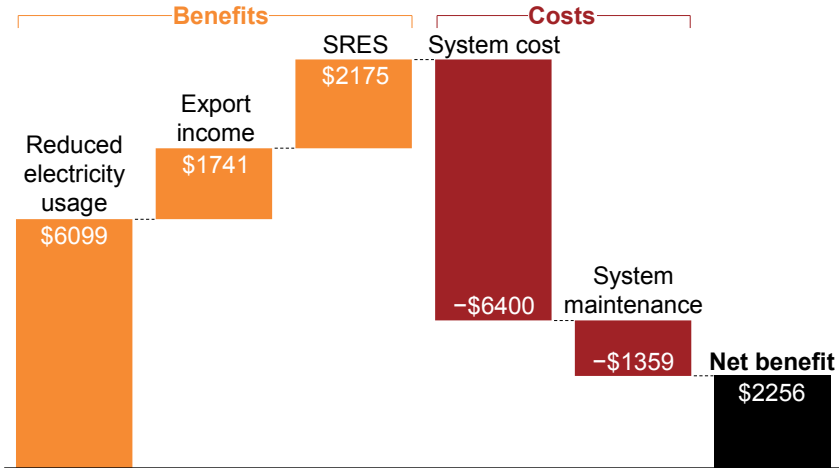
Figure 25: Net present benefits and costs of a three-kilowatt solar PV system, demand tariff, Brisbane



Source: Grattan analysis of Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012), Solar Choice (2015), Energy Australia (2015), Origin Energy (2015), AGL (2015).

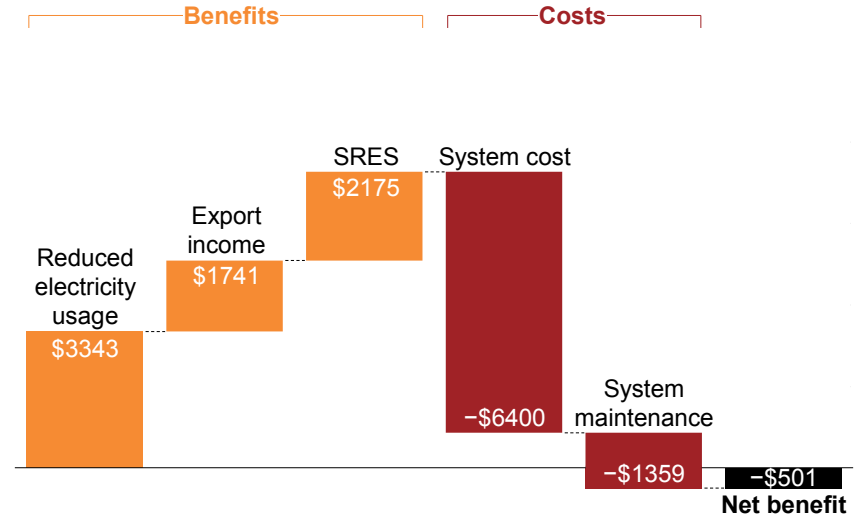
Adelaide

Figure 26: Net present benefits and costs of a three-kilowatt solar PV system, current tariff, Adelaide



Source: Grattan analysis of Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012), Solar Choice (2015), Energy Australia (2015), Origin Energy (2015), AGL (2015).

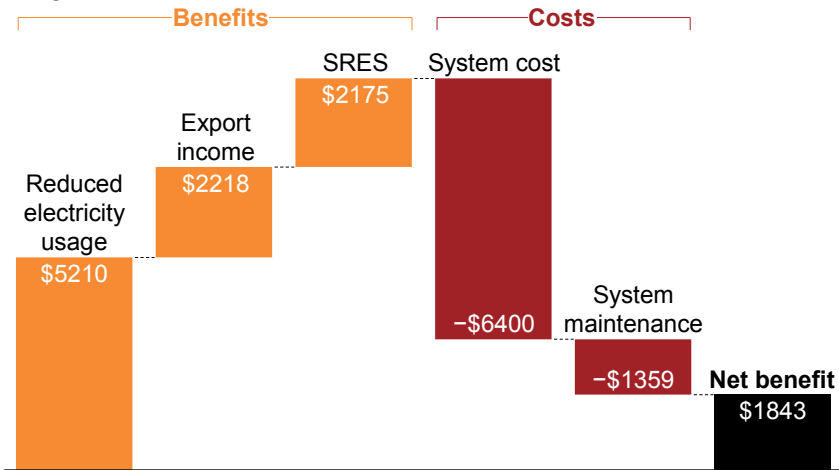
Figure 27: Net present benefits and costs of a three-kilowatt solar PV system, demand tariff, Adelaide



Source: Grattan analysis of Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012), Solar Choice (2015), Energy Australia (2015), Origin Energy (2015), AGL (2015).

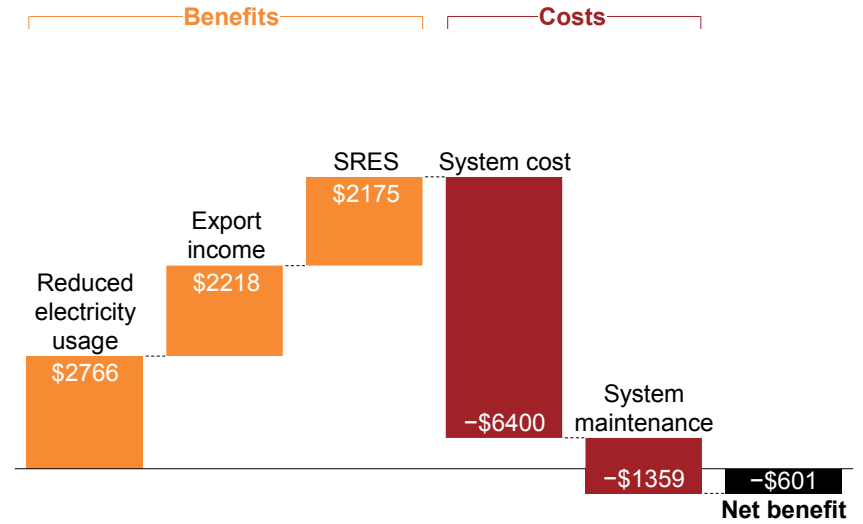
Perth

Figure 28: Net present benefits and costs of a three-kilowatt solar PV system, current tariff, Perth



Source: Grattan analysis of Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012), Solar Choice (2015), Energy Australia (2015), Origin Energy (2015), AGL (2015).

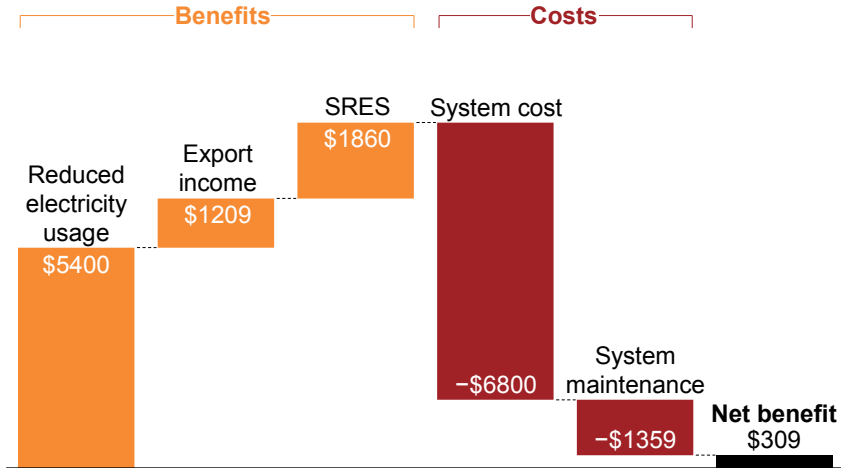
Figure 29: Net present benefits and costs of a three-kilowatt solar PV system, demand tariff, Perth



Source: Grattan analysis of Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012), Solar Choice (2015), Energy Australia (2015), Origin Energy (2015), AGL (2015).

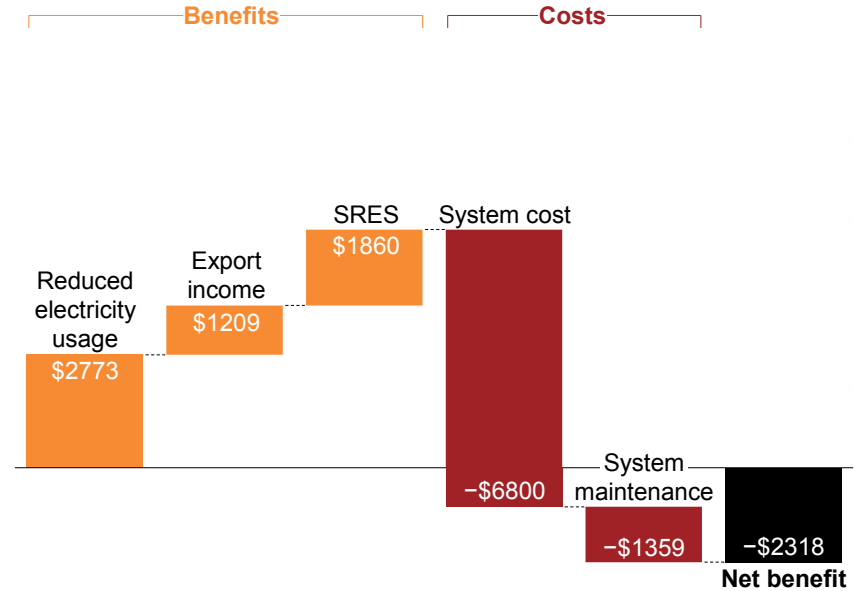
Hobart

Figure 30: Net present benefits and costs of a three-kilowatt solar PV system, current tariff, Hobart



Source: Grattan analysis of Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012), Solar Choice (2015), Energy Australia (2015), Origin Energy (2015), AGL (2015).

Figure 31: Net present benefits and costs of a three-kilowatt solar PV system, demand tariff, Hobart



Source: Grattan analysis of Victorian Government (2014), AEMO (2015a), BOM (2015), ABS (2012), Solar Choice (2015), Energy Australia (2015), Origin Energy (2015), AGL (2015).