Final Report to

Victorian Department of Primary Industries

Benefits and Costs of the Victorian FIT Scheme

17 November 2008

McLennan Magasanik Associates

Ref: J1639

Project Team

Melbourne Office
242 Ferrars Street
South Melbourne Vic 3205
Tel: +61 3 9699 3977
Fax: +61 3 9690 9881

Brisbane Office
GPO Box 2421
Brisbane Qld 4001
Tel: +61 7 3100 8064
Fax: +61 7 3100 8067

Email: mma@mmassociates.com.au
Website: www.mmassociates.com.au

TABLE OF CONTENTS

1 INTRODUCTION

The Victorian Government is proposing to introduce a feed-in-tariff for exports of energy from photovoltaic generation technologies.

Feed-in-tariffs have been successful in increasing the uptake of renewable generation in a number of countries overseas (particularly Germany and Spain). The advantages of this type of arrangement relative to other types of support measures includes the certainty provided to investors in their returns and the ease with which the program can be used to support a range of technologies. The disadvantages include the difficulty in determining an appropriate tariff rate that overcomes the relevant market failures but does not provide excessive profits to suppliers and the potential high expense of the scheme to electricity consumers.

The Victorian Government announced a commitment, on 6 May 2008 to introduce a new premium feed-in tariff scheme aimed at increasing the number of private households in Victoria generating renewable electricity from small scale PV systems. The proposed Victorian scheme will pay households 60 cents for every kilowatt hour of electricity fed back into the state's electricity grid. The scheme will be introduced in 2009 and run for fifteen years.

The scheme is intended to apply to systems up to 2 kW capacity and have a cap of 100 MW of generating capacity. However, the Victorian Government has asked MMA to examine alternative options on tariff rates, scheme coverage and eligible system size. The results of this analysis are outlined in this report.

2 POTENTIAL FOR FEED-IN-TARIFF

2.1 Advantages of small scale generation

Whilst there is the potential for a substantial amount of small scale generation to enter the Australian market, it will be competing against some other sources of generation. Small scale generation brings many advantages to the market including diversified supply sources and improved supply reliability. With the exception of gas-fired micro turbines, small scale generation does not incur fuel costs. In the longer-term, widespread adoption of small scale generation could also reduce network costs. Unfortunately, the capital cost of small scale generation is currently much higher than for large scale generation and this has hampered its adoption.

Government programs may help to reduce or overcome this capital cost disadvantage. Policy responses may range from removing regulatory obstacles to providing direct support for small scale generation. Australian Governments have already assisted by removing some of the obstacles in the market place. Plans to abolish the retail price cap have been announced. A rollout of interval meters has also been announced. In conjunction, both policies should encourage time of use tariffs and these would enable some small scale generation options (PV or solar based systems) to capture the full value of its energy.

However, some direct support may also be needed. This support can be justified only if the level of support would induce a long-term decline in system costs quicker than it would have occurred otherwise or overcome some other market failure. Justifying support purely on the grounds of abating greenhouse emissions can be criticised on the basis that there other measures that can reduce emissions more cost effectively (and indeed the Australian and the Victorian Governments are active supporter of a national emission trading scheme, announcing that it will introduce a national scheme by 2010).

Internationally, feed-in-tariffs are now becoming a popular mechanism to support small scale generation. Germany and Spain have introduced feed-in-tariffs to support a range of renewable generation options, including large scale options. Legislation has been enacted in these countries that specifies the price to be paid to generators for energy exported to the grid from eligible generation options and these prices apply over an extended period of time. The set prices are higher than standard wholesale electricity prices and in many cases higher than retail tariffs. Typically, different tariff rates are applied to each type of generation technology, with the rates usually based on the minimum revenue required to cover the costs associated with a particular technology. The feed-in-tariff works in these countries as their institutional and market arrangements for electricity allow for liability to be defined easily (since retailers have geographical monopolies). Nor do these countries deploy other market based support such as an MRET style program.

Feed-in tariffs can provide for the support of a range of technologies (portfolio approach), rather than the cheapest only (generally wind).

Feed-in tariffs are not additional to the wholesale electricity price; they define the total minimum price to be received by the eligible generators.

Feed-in tariffs can be varied in a number of ways to suit local requirements, for example:

- Feed-in prices can be one fixed rate, or set as a percentage of retail prices. They can be scaled according to plant capacity factor, differ seasonally, or change over time.
- Premium rates of up to ten times the retail tariff.
- In some schemes, the tariff decreases annually (e.g. German scheme).

The time frames over which feed-in tariffs apply can be varied, usually between 15 to 20 years.

There is a degree of uncertainty surrounding the level of eligible generation and compliance cost under a FIT scheme.

A key administrative issue for a FIT scheme is where liability falls. Typically, feed-in tariffs are employed where retailers have geographical franchises. With the NEM characterised by competitive retail markets, there is no geographic franchise and so there is no clear party for liability to be imposed.

The large number of small distributed generation systems that a feed in tariff would encourage may also result in additional benefits in delaying the need for upgrades in local distribution networks. This would occur only where significant numbers of PV systems were installed and is a direct result of a significant proportion of generation arising within the distribution system rather than having to be transmitted into the network from external sources. Since local distribution capacity is determined by the need to supply local peak demand, distributed generation would only avoid network costs if it reduced the need for imported energy during peak demand periods. The ability of distributed PV systems to reduce peak demand will vary. In most regions dominated by households, for example, peak demand will often occur in the evening time during summer (when air-conditioners are on and when householders are operating other appliances). Because solar insolation is lower during these periods, the contribution by distributed PV systems to lopping peak demand in these regions will be lower than the nominal capacity of the installed systems. However, regions with a high proportion of commercial businesses, there may be a good correlation between peak demand and peak PV generation[1].

The delay of a required distribution or transmission system upgrade by even a relatively short period could result in significant cost savings. This saving may usually encourage network planners to provide additional support for PV installation so that they can

1 See, for example, Energy Australia (2005), *Kogorah Town Square Photovoltaic Power System Demand Management Analysis*, in which they show a high correlation between PV generatin and demand. However, because of the potential variability in PV output, only 35% of the PV capacity was considered to be firm.

materialise the savings in the upgrade costs that they would otherwise incur. However, under currently regulatory practises, this incentive is muted as the revenue cap arrangements provide them with incentives to earn revenue from network upgrades.

2.2 Potential market failures

In most states in Australia, small scale PV may be disadvantaged through market failures which fail to take into account the value and benefits to the electricity network which arise from the adoption of generation technologies embedded within the electricity network and the environmental benefits through reduced carbon emissions and other pollutants. PV micro-generation may be competitive if the full cost of externalities is taken into account in the design of tariffs for electricity generated by distributed or embedded generation.

Peak solar output of PV systems may correspond closely with times of peak demand, typically during summer afternoons with high air conditioner use. On the other hand during off peak hours usually at night, solar PV output is zero. At peak times, the pool price frequently rises well above average pool prices, often reaching hundreds, or thousands of dollars per MWh. Extra generation of electricity by small scale distributed solar PV systems at these times of peak demand reduces system demand and thus lowers the wholesale price of electricity. Distributed solar PV thus contributes most when wholesale prices are highest. However, owners of solar PV panels are unable to capture this benefit of reducing system demand during high price periods if the PV system simply reduces the energy consumed by the house on which the PV system is installed. One-for-one tariffs metered on a net basis (i.e. only on the amount exported to the grid) do little to encourage new investments in small PV systems. Even if the electricity generated is exported into the grid, if the buy back tariff is simply the equivalent of the general use tariff, the benefits of generating during times of peak system demand is not reflected as average retail prices on which general use tariffs are based are not an accurate reflection of cost of the value of PV to the market during these peak periods. More innovative tariffs are not offered for several reasons including lack of adoption of interval metering (not necessarily a market failure) and the imposition of retail price caps for some customer classes.

Solar PV also has benefits for the network which often the tariffs fail to reflect. The retail prices charged for electricity which includes network charges faced by small customers are a highly averaged price. It does not incorporate any locational and time-of-use price signals to indicate to the customer the real network cost of their load. During times of peak system demand, the marginal cost to the network is much higher than the averaged network charges faced by customers as the cost of network augmentation to manage system load is driven by the extent of peak demand. Buy back tariffs that are the equivalent of general use tariffs thus do not accurately reflect the value that distributed solar PV systems bring to the network. Solar PV generation which provides embedded energy during high demand periods is under-compensated for its network benefits as well as for its generation. These market failures have led to inefficient investment decisions - overinvestment in networks and underinvestment in distributed energy solutions.

Under the existing arrangements, embedded generators can make a case to have some of the benefits of deferred network upgrades passed on, as occurred with the Somerton Plant in Victoria, which received some payments for the benefits perceived from deferred system upgrades. Nothing in the rules prevents embedded generators being able to negotiate with network service providers to share some of the benefits from embedded generation[2], but there is often a perception that an asymmetry issue exists in that only the network service providers truly know the value of the network benefits and would have an incentive to under report these benefits. This is likely to be accentuated when the source of energy is coming from a number of dispersed households, each only contributing a small part to the total embedded generation capacity.

Another benefit that embedded generators bring to the electricity market that should be available to proponents is the reduction in network losses. As electricity is transported through the wires in the transmission and distribution system, energy is lost in the form of heat. This loss is exponentially related to the load demand. By siting a generator near a load, the amount of energy required to be imported from the network is reduced. This reduces the losses incurred by the network for all other customers. While larger embedded generators are usually able to include this benefit in their negotiations for connection to the system, this benefit is not likely to be reflected in tariffs for dispersed small scale generators. Savings in losses to other customers in the region are typically not captured under existing tariff arrangements.

At present, while South Australia, Victoria, the ACT, and Queensland have implemented, or are implementing feed-in tariffs that are greater than normal tariffs, the level of feed-in tariffs offered in the remaining states and territories are left to the retailers to determine. Even in the states which offer a premium for feed-in tariffs, the quantity exported to the grid is based on net exports rather than gross generation. This means that only excess energy exported to the grid is able to earn a return. For small systems installed by families that are home during the daytime, it is likely that no exports are possible. However benefits to the grid still exist as in the absence of this source of electricity, extra demand will be placed on the grid. Feed-in tariffs with a premium on general use tariff based on gross generation will provide the incentive to install micro generation facilities. The difficulty is that while it is the electricity retailers that offer feed-in tariffs, the benefits are captured by networks. As a result, it will probably require distribution networks to contribute funds which they can recoup through the distribution pricing process. This will encourage the take up of small scale distributed generation technology.

Network operators control access to information regarding their networks and have the ability and under the regulatory regimes often the incentive to impede access by

2 In fact, such arrangements can beneift network service providers as the payments could be deemed to be outside the regulated revenue arrangements governing their revenue streams from regulated network services.

embedded generators given that presence of such generators may reduce the need for network augmentation. Network owners are also normally the planning authority. Incentives in the economic regulatory framework that apply to networks encourage network businesses to grow their assets while maintaining network reliability in order to increase revenue. Alternative solutions to maintain or improve network reliability such as distributed PV generation do not have the same incentives. As a result, a conflict of interest arises when network service providers are expected to assist embedded generators in their connection to the network.

In summary, potential embedded generators often complain that the potential for embedded generation is impeded by a number of barriers including:

- Difficulties in accessing network operation information during negotiation on network connection agreements and costs. The embedded generation proponent does not have full information on their use of the network system, so may incur higher costs for connection to the transmission network.

- Lack of requirements for embedded generation to be explicitly considered where augmentation of networks is being considered. The regulations do require that network service operators consider alternatives to network upgrades as part of the approval process for these upgrades, but often the information is sought too late to allow the full development of alternative proposals.

- Network pricing structures that includes high stand-by charges with minimum chargeable demand that are only used when the embedded generator is not operating. This requirement penalise customers that self-generate, having to incur both the costs of generation as well as network demand charges that other generators do not incur.

- Low 'buy back' rates for electricity to be exported to the network that do not reflect a proper recognition of the network benefits that the generator brings to the network including the reduction in losses, network augmentation and potentially improved supply reliability.

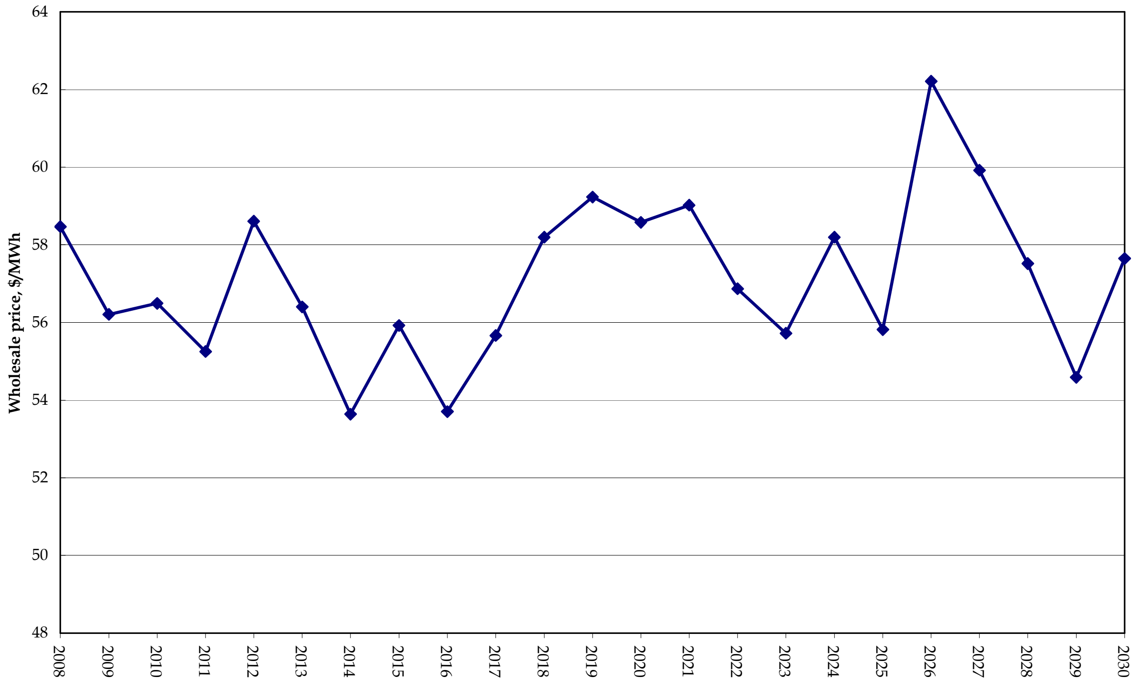
Thus, under current energy market arrangements, there is the prospect that small scale distributed generators may not get benefits from supplying energy during high price periods and from avoided network fees. To the extent this is true, it suggests that the tariff should be set at a rate that is equivalent to the value of the foregone benefits. However, further analysis is required to determine the potential and materiality of these market failures in the context of widespread adoption of small scale PV systems.

2.3 Estimates of the potential value

A review of the literature showed some diversity of opinion on the economic value of PV generation. There was general agreement on the following values for PV generation

- Cost of wholesale energy avoided. In Victoria, this would be equivalent to the volume weighted spot price (that is, weighted to the pattern of generation for PV systems) on wholesale markets plus avoided NEMMCO and system fees (which amount to around $1/MWh to $2/MWh). Volume weighted average spot prices for small residential and business customers are around $58/MWh in Victoria. For a PV weighted generation profile, prices could average around $70/MWh to $75/MWh. Add to this contract premiums in the order of 10%, which is usually the basis for contracts between retailers and generators.

Figure 2-1: Volume weighted spot market price projections, Victorian regional reference node



- Cost of energy losses during transmission and distribution of grid supplied systems. Energy losses will vary by regions within Victoria, with values varying from 5% to 10%. Note that since intraregional network losses are calculated as an average over the whole year, the true value of the losses that a PV can avoid may be underestimated. This is because PV generation typically occurs in peak demand periods when load on the networks is greatest and therefore network losses are highest. The averaging procedure used to calculate network losses can therefore underestimate the actual losses avoided. Since hour by hour loss estimates are not published, it is difficult to estimate the true value for losses, but a rough guide would be around 5% above the average values.

- Value of avoided greenhouse gas emissions. Again this value will vary by state, since the emission intensity of conventional generation avoided varies by state. For every $10/t CO_2e carbon price, the value is likely to be around $9/MWh to $13/MWh in Victoria. There is some disagreement in the literature on whether this should apply only when a carbon impost is imposed. Another issue is whether the value should be equivalent to the market price of carbon emissions under mandated emission abatement schemes or a true social value should be employed[3]. However, estimating the true social value of carbon abatement is extremely difficult

- Retail margins, which are typically 5% of the all up cost to customers (around $6/MWh to $10/MWh, depending on customer class).

However, there is considerable contention on what portion of the network costs are avoided. The bulk of network costs are fixed, with the actual level of costs dependent of maximum demand in any year and to a lesser extent energy consumption. For this reason, network tariffs are structured in fixed and variable cost components. The variable components usually cover part of the cost of shared network infrastructure (the component that is considered a "joint" cost and cannot easily be apportioned by customers). The fixed cost covers the cost of provided infrastructure to meet peak demand.

To the extent that PV generation can reduce peak demand then it can be reasonable argued that it could reduce network fees. However, some commentators argue that although distributed roof top PV generation does occur during the high demand period in summer it does not significantly reduce the local peak demand because the peak demand in many residential areas occurs in the early evening when PV generation is diminishing. A closer examination of the literature, however, reveals this to refer to the peak demand period for the local distribution network, and typically reveals that PV generation can reduce peak load by between 15% to 30%. But for the wider transmission system, peak demand may still occur in the early to late afternoon periods, so that PV's potential contribution to avoiding sub-transmission costs may be higher.

Further, the contribution to reducing network costs is likely to vary by voltage class and region. The basic assumption is that a portion of the variable network charge could be avoided, which varies in Victoria from between $5/MWh to $20/MWh.

A summary of the avoided costs due to small scale distributed generation is contained in Table 2-1. Note that the estimates are the high and low range for an average avoided cost across all regions within Victoria. The estimates indicate a value for the energy produced by a PV system of between $100/MWh to $150/MWh or 10 c/kWh to 15 c/kWh. This applies to gross output. On a net output basis, this is equivalent to 33 c/kWh to 50 c/kWh, assuming only 30% of the generation is exported to the grid. This compares with the stated rate for the Victorian FIT of 60 c/kWh on a net basis.

3 Caps under an emission trading scheme may be set at a lower that socially optimal levels due to a number of political and social factors. Action on abatement may also be limited until all countries are signed to an international agreement. To the extent this is true, then the true value of carbon abatement may be higher than the clearing price under an emission trading scheme.

Table 2-1: Costs avoided by small scale distributed PV generation, $/MWh

Item	Low estimate	Upper estimate
Wholesale spot price	70	75
Carbon price impact	10	28
NEMMCO Fees	1	2
Contract premium	7	8
Network losses	4	8
Retail Margin	6	10
Avoided network fees	5	20
Total	**103**	**151**

Carbon price impact calculated by assuming a carbon price ranging from $12/t CO_2e (low estimate) to $34/t CO_2e (high estimate) and an emission intensity of 0.8.

2.4 Role for Feed in Tariff

Feed in tariffs have been used in other countries to develop the photovoltaic industry. However, they are probably not the most effective tool for this purpose because there is no guarantee that the money will flow to domestic industries. Industry development is better handled by short term assistance such as capital subsidies to manufacturers. A feed in tariff can also be used to overcome some barriers to technological development and deployment, although an expanded renewable energy target is expected to fulfil this role in Australia for a range of renewable energy technologies.

However, a feed in tariff is a useful policy mechanism for overcoming a number of market failures in relation to electricity markets in Australia. These include:

- Imposition of retail price caps or uniform tariff policies which mean that the true cost of electricity supply is not seen by electricity customers.
- Lack of interval metering which results in a lack of use of time of day tariffs, which again diminish the value of generation during peak price/demand periods.
- Network losses tend to be smoothed across distribution systems, which diminishes the value of distributed generation at the end of grid locations and some regional locations.
- Network benefits of distributed generation such as roof top PV systems may not be appropriated by customers with PV as the value of these benefits can only be known by network operators who have no incentive under current regulatory arrangements to reveal the true value of the benefits.

Thus, a feed-in-tariff can be used as a second best policy instrument to overcome these market failures. The idea is to set the feed-in-tariff at a rate equivalent to the benefits of distributed energy systems including benefits not able to be captured under current market arrangements. The adoption of a feed in tariff should only be for a short duration as the emphasis should be to remove the market failures with specifically target policies (i.e. removing price caps, installing interval meters and so on). The feed in tariff would only be in place while other more targeted policies are being implemented.

Another key aspect of this approach to justifying feed-in-tariff is that the tariff itself would differ by State/Territory and by regions within States/Territories. This is because the value of the benefits is likely to differ across regions. Network benefits, for example, are likely to be higher in regional areas distant from generation centres.

However, Governments that have implemented a FIT tend to adopt a single rate across their state.

MMA's view is that the principles for setting the FIT should be harmonised, not the rate itself. The principles would be based around enforcing a set of procedures for calculating FIT for each major transmission/distribution off take point. The procedure would be along the lines of:

- Determine the expected wholesale price at the regional reference node or central delivery point for different intervals of each day (including the impact of permit prices).
- Calculate network losses to each distribution off take point.
- Calculate retail margins (avoided from not purchasing electricity through the local retailer).
- Calculated avoided network costs including the benefit of deferring network upgrades.
- Sum the components to arrive at a final $/MWh or c/kWh tariff.

By implication, this procedure would lead to different FIT rates across the electricity supply systems reflecting differences in the economic value of distributed generation across the system.

3 METHOD AND ASSUMPTIONS

3.1 Method of analysis

The task is to develop a model to estimate the uptake of small scale generation through a feed-in-tariff. The focus will be on photovoltaic technologies.

For this purpose, MMA has developed a model of distributed generation focussed on small scale renewable generation options.

In the model, uptake of eligible technologies will be affected by a number of factors. The model determines the uptake of PV technologies based on net cost of generation (after FIT revenue is deducted from costs) versus net cost of grid delivered power. Because the cost of small scale generation will vary by location, the model calculates uptake based on differences in key assumptions by location. Other factors that may impact on the decision will be modelled as a premium prepared to be paid for small scale generation. This premium will be assumed to decrease as the rate of uptake increases (reflecting the fact that the willingness to pay will vary among customers).

The cost of small scale technologies will be treated as an annualised cost where the capital and installation cost of each component of a small scale system (modules, turbines, inverters, BOS) is annualised over the assumed lifespan of each component, discounted using an appropriate weighted average cost of capital.

The model includes:

- Coverage of small scale renewable technologies including PV, micro hydro-electric and small scale (roof-top) wind generators. In this study, only PV systems are considered.
- Coverage of residential customers.
- Includes feed-in-tariffs as a potential revenue stream.
- Covers multiple regions (major transmission node regions within Victoria). The model was disaggregated by major distribution nodes to account for differences in solar insolation levels for photovoltaic generation and wind speed for wind turbines. The number of households and other eligible customers in each region was the basic unit for modelling. That is, the costs of delivered electricity is modelled for each household or other customer group where these customer groups will be defined by insolation levels, wind speeds, and other local load profiles.
- The degree to which each customer grouping will adopt solar/PV technologies also depends on tariff arrangements, with assumptions made on the uptake of interval meters and the time of use tariffs. Interval meters (and time of use tariffs) have been assumed to roll out into the market at 10% of the installed base per year. The price paid for the time of use metered electricity from renewable source has been estimated

based on the output profiles of the renewable technology and the hourly electricity prices. These prices, which tend to be higher than averaged prices are utilised where renewable generation occurs but no feed in tariff applies.

The model has a built in function to reduce the cost of generation from small scale technologies as a function of adoption of these technologies. International studies have indicated that the level of utilisation is likely to be the best predictor of future cost reductions through learning by doing. Economies of scale in production of system equipment are likely to be achieved as the capacity installed increases. However, as this is a contentious area, it is assumed for the present analysis that costs are reduced according to international trends in system costs.

3.1.1 Model Structure

The model is designed to provide estimates of the uptake of small scale renewable distributed generation and the social benefits and costs of this uptake.

Uptake of distributed generation is a function of the relative cost to end-users of distributed generation and supply of electricity from the grid. Uptake of distributed generation will occur up to the point at which it becomes more expensive than grid supplied electricity at the retail level.

The model estimates the cost of electricity supply to each off-take point. At each off take node, the lowest cost mix of distributed and grid supplied electricity is calculated for the study period. The model effectively assumes one representative customer (for the relevant customer classes) at each off take point that is able to source electricity from the lowest cost option. Small scale distributed generation is chosen when the cost of that generation (on a levelised basis) is lower than the variable component of delivered retail price of energy supplied from the grid. A number of constraints on the uptake of distributed generation are imposed as described below.

The level of distributed generation depends on the cost of distributed generation net of any benefits that may be captured by the distributed generator under existing market arrangements.

Data on peak demand at each transmission node are readily available from VENCorp. The nodes are also characterised by different costs for each distributed generation option.

The unit sizes are assigned to each technology in line with the expected scale of individual units.

In each off take node (region), the avoided cost of grid supplied electricity is the sum of:

- Volume weighted wholesale electricity price (as affected by assumed carbon prices as discussed in Appendix A, Section A.1.4) adjusted by the marginal loss factor applying on networks to the node, including distribution losses, plus
- Contract premiums, plus

- Transmission and distribution use of system fees, mainly the variable components, based on published network fees, plus
- Retailer margins.

Costs for each component are in real dollar terms. Note that since the wholesale price will vary from year to year, so will the delivered retail price.

For each distribution generation option, the full costs of generation are modelled. Costs include:

- Capital cost, which are modelled as a function of capacity (to reflect the economies of scale with unit size). Capital costs are reduced over time.
- Operating and maintenance costs.
- Transmission connection costs (but not deep connection cost as the assumption is that the plant will supply local loads).
- Network fees for backup supply.
- Carbon price for purchase of emission permits to cover emissions from electricity generation.

Potential economic benefits are captured in three ways. First, some net benefits are subtracted from the sum of the costs to the extent that the benefits can be captured under the assumed regulatory arrangements. This applies to avoided network upgrade costs, whereby the net present value of the deferment of capital expenditure on any upgrade is subtracted from the cost of distributed generation. The deferment is calculated by determining the time the upgrade proceeds without distributed generation (based on information on upgrades available from VENCorp), which occurs when peak demand exceeds the notional capacity of the transmissions and distribution system. The firm capacity of distributed generation is added onto the notional capacity of the existing transmission and distribution system[4].

Second, some costs may be avoided by distributed generation but added onto the cost of grid supplied electricity. If there is a price on the release of carbon, then the cost of emissions is added onto both the grid supplied option and distributed generation option depending on the emission intensity of each supply option. Similarly, there is provision for network fees for network services to be avoided for the load supplied by distributed generation (in regions where the regulations allow for this).

Third, the model has the capability for the user to impose an externality benefit to the extent that distributed generation avoids emissions of other harmful pollutants (which are currently not taxed or regulated). This can be done for emissions of NO_x, SO_x and particulates. However, we do not consider these externalities for this study.

[4] In this study, the benefit of deferred network upgardes was found to be small as the uptake of small scale generation in any region was not sufficient to avoid any planned uptake until well past 2020.

A number of constraints that limit the uptake of distributed generation are included in the model:

- *Economic constraints*. As the capacity of distributed generation in a region increases, the unit cost of generation also increases[5]. In the case of wind generation, this is modelled as reduced capacity factor as more wind generation is selected (to reflect the fact that as more wind farms are built, they are likely to locate in less windy areas). In the case of PV this is modelled as increasing capital cost to represent the likely increase in installation costs where demand increases faster than the capacity of installers and reduced energy output per kW of capacity as less favourable sites are chosen.
- *Technical and regulatory constraints*. A number of maximum capacity limits are imposed to mimic the impact of technical limits to uptake in a region or other regulatory impediments. The maximum capacity limits can also be used to model the effect of social issues such as the amenity affect of wind generation in residential areas and some sensitive sites.
- *Geographic constraints*. The off take nodes have been divided into metropolitan and rural nodes and have been utilised to assign the availability of potential capacity in a region for wind and hydro resources.
- *General constraint* that the capacity of distributed generation does not exceed the local peak demand (as this would entail the need to export power to other regions which would incur additional costs not modelled).

3.2 Key assumptions

Below we outline the key assumptions used in our analysis of the policy measure. Other assumptions on variables affecting the electricity markets are outlined in Appendix A.

3.2.1 Local demand

Forecasts of local demand at each node were derived by taking the actual peak demand for 2006/07 as published by state based transmission planners and then applying the state wide peak demand growth rate as forecast by NEMMCO. Peak demand in 2006/07 for each node is shown in Table 3-1. Energy consumption for each region was calculated from peak demand by using the state wide load factor. A correction factor was applied to ensure that the sum of energy consumption at each node equalled state-wide energy consumption.

5 This is done to represent both the actual likelihood of rising costs as supply increases and to avoid what is known as the "flip flop" effect that occurs with average cost assumptions, where the model chooses nothing but distributed generation once the cost of distributed generation is lower than the cost of grid supplied electricity.

Table 3-1 Peak and energy demand assumptions in 2007/08 - Victoria

Node	Peak Demand, MW	Energy Consumption, GWh
Altona	455	2,815
Ballarat	163	1,006
Bendigo	200	1,232
Brooklyn	123	763
Brunswick	87	538
East Rowville	482	2,977
Fishermen's Bend	260	1,607
Geelong	360	2,222
Glenrowan	91	561
Heatherton	332	2,052
Kerang	68	422
Loy Yang	411	2,534
Malvern	183	1,129
Mt Beauty	36	223
Richmond	622	3,845
Ringwood	525	3,244
Shepperton	281	1,734
Springvale	455	2,812
Thomastown	675	4,168
Wodonga	92	569
West Melbourne	521	3,218
Yallourn	4	23

Source: VENCorp and MMA analysis.

3.2.2 Technical assumptions

Assumed technical parameters for the distributed generation option are shown in Table 3.2. Although the model can handle variations in the assumptions by region, we assumed that the technical assumptions for PV generation technology were the same in each region.

Table 3-2 Technical assumptions for distributed generation option

	Rooftop PV
Annual uptake limit as a maximum proportion of total demand, %	0. 1
Maximum plant size, MW	0.002
Capacity factor, %	16.3 – 19.2
Outage rates, % of year	3

Note: PV capacity factors vary by region according to solar insolation levels. PV systems above 2 kW are assumed to get the one-for-one tariffs currently provided by retailers. However, according to the simulation results, only a very small number of systems above 2 KW (less than 10) are found to be installed. Annual uptake limit designed to limit uptake in early period of scheme to around 15 MW per annum to reflect current manufacturing capacity and limited availability of qualified installers. Source: MMA analysis.

Capital costs

It is assumed that in each region, the actual plant size will be equal to maximum allowed size except for the last plant chosen, which may have a lower capacity.

Unit capital costs are also assumed to decrease over time reflecting long-term trends. Photovoltaic system capital costs are assumed to decline by 5% per annum until 2020 and then at 3%[6].

Capital costs are annualised over the life of the plant, assumed to be 25 years for all plant. Costs are annualised using a real weighted average cost of capital set at 5% above the risk free long-term bond rate (which based on latest 10 year treasury bond rates is about 5.3% per annum in real terms).

3.2.3 Photovoltaic System Parameters

Costs

The average installed system cost for residential PV is around $12,500/kW[7] in Australia for a typical 1.5 kW roof top system. Smaller systems cost a little more and larger systems a little less by achieving some economies of scale and bulk purchase of panels.

There is an international market for PV modules, which keeps pricing in individual countries reasonably linked. Module prices have actually been on the increase since 2003 due to very strong demand for PV, driven by strong government incentive programs in countries such as Germany, Japan and California and a shortage of crystalline silicon feedstock. This contradicts the expected long-terms cost reduction trend expected from improving technology and higher production volumes. Manufacturers have responded by investing heavily in more manufacturing capacity. Underlying costs should continue

6 See IEA (2008), *Energy Technology Perspectives* 2008, Paris. (pp 373). The IEA asserts that in the past learning rates of 15% to 20% have been achieved for PV technologies. Assuming a learning rate giving an 18% cost reduction per doubling of capacity and assuming that global PV capacity increases from the 5,700 MW to 33,000 MW in 2020 (at a growth rate a little over 1,500 MW, which is the current growth rate), then PV costs systems costs from $12,500/kW to $6,900/kW, representing an average declien of around 5% per annum.

7 This includes the installed cost of a PV system before REC revenue, FIT revenue and rebates are deducted.

to fall despite the current market price and there is an expectation that prices will return to a steady fall as the market matures.

Predicting the future price of any product is difficult and subject to large uncertainties. The key parameters that will determine the future cost of PV cells include:

- Raw material cost
- Other input costs
- Economic conditions
- Demand and production levels
- Technology.

Many of these parameters are interlinked and improvement in one may force higher costs in another, for example, as costs fall due to increased economies of scale in manufacturing, upward cost pressure may be applied due to the increased demand forcing up raw material costs. However, technology improvements may reduce the quantity of raw material required or the type of material necessary.

Historical data over the past 25 years have revealed that there has been a 20% cost reduction for every doubling of the cumulative production of PV cells globally. This linear behaviour of cost with cumulative volume is typical of most manufacturing, and is expected to continue at the historical value of 20% for each doubling of cumulative production volume. It is expected that installed costs will fall by approximately 5% per year over the period to 2020 and 3% thereafter, assuming that demand continues to rise and that manufacturing capacity can keep pace with this demand.

Capacity Factors

Photovoltaic cell output is directly related to the intensity of the sunlight falling on the panel. The sunlight intensity or solar insolation varies with global position, effectively distance from the equator, and local climate such as cloud cover. Across Australia the solar insolation varies significantly and will affect the output of a given solar array dependant on its location. To account for these variations we have estimated the PV system capacity factors at each of the transmission nodes employed in the analysis using the RET Screen PV Energy Model[8]. The key input for this analysis is the geographic coordinates of the locations involved, the orientation, configuration, and tracking of the panel, and the monthly average temperature and solar radiation. The climate data are available from the NASA Surface Meteorology and Solar Energy Data Set[9].

The resulting system capacities range from 16.3% in southern Victorian and elevated locations to 19.2% in north western Victoria.

8 RETScreen Energy Project Analysis Software, Clean Energy Decision Support Centre, www.retscreen.net

9 http://eosweb.larc.nasa.gov/sse/RETScreen/

Table 3-3: PV System capacity factors by location[10]

Region	PV System Capacity Factor
Altona	16.944
Ballarat	17.326
Bendigo	18.484
Brooklyn	16.939
Brunswick	16.934
East Rowville	16.706
Fisherman's Bend	16.914
Geelong	17.694
Glenrowan	18.088
Heatherton	16.708
Kerang	19.262
Loy Yang	16.741
Malvern	16.699
Mt Beauty	17.819
Richmond	16.939
Ringwood	16.694
Shepparton	18.428
Springvale	16.706
Thomastown	16.682
West Melbourne	16.938
Wodonga	18.053
Yallourn	16.738

Calculated using the RETS Screen International Model available at www.netscreen.net. Calculated for a fixed PV array with a 30 degree slope, based on a BP mono-silicon technology (BP 1570 S model)

3.2.4 System parameters

Over the duration of any FIT scheme it is expected that the costs of the generation technologies will fall as manufacturing volumes increase. Costs over time have been assumed to decrease according to historical price reductions in each of the technologies modelled. The reductions have also been assumed to decline in the future as the technologies become more mature. The rates of these cost reductions are shown in Table 3-4, with the capacities, initial 2008 costs and other operating parameters.

10 These were the same capacity factors as MMA used in early modelling for Sustainability Victoria

Table 3-4 Modelled system parameters

	Units	PV System
System Size (typical system size)	kW	1.5
2008 Installed Cost	$/kW	$12,500
Capital Decline Factor 2008-2015	%	5.0%
Capital Decline Factor 2016-2020	%	5.0%
Capital Decline Factor 2020-2030	%	3.0%
Capacity Factor - Max	%	19.2%
Capacity Factor - Min	%	16.3%
Annual Energy Output - Max	kWh	2,536
Annual Energy Output - Min	kWh	1,708
Max % of total Load	%	0.010%

Typical system size is less than the maximum system size eligible under the proposed FIT measure as limits on roof space, shading and inappropriate orientation limit system sizes on typical households.

It is assumed that 30% of output from a roof-top PV system is exported to the grid. That is, 70% of the electricity generated is used in the household.

3.3 Feed in Tariff Scenarios

Parameters for the feed in tariffs scenarios used in the modelling are as follows:

- *Scenario 1. Stated Policy*
    - 60 c/kWh on net metered output (nominal terms)
    - 100 MW cap on installations and 2kW maximum system size
    - 15 year duration of scheme commencing in 2009. This means that households get 15 years of revenue from the FIT if a PV system is installed in 2009, 14 years of revenue from the FIT if the system is installed in 2010, 13 years if installed in 2011 and so on.
    - Eligibility for all Victorian residential customers
    - Tariff paid by electricity retailers with provision for pass through
- *Scenario 2: Status Quo*
    - Current arrangements
    - Minimum tariff equivalent to retail purchase tariff
    - Net metered output
    - 100 kW cap per individual system
    - No end date
    - Tariff paid by retailers with pass through

- *Scenario 3: SA Scheme (in Victoria)*
  - Stated policy with 44 c/kWh tariff
- *Scenario 4: Stated Policy on Gross Output*
  - Stated policy with 60 c/kWh tariff paid on a gross basis (i.e. on every kWh of PV electricity generated).

Carbon prices and other key electricity market assumptions are listed in Appendix A. In summary, carbon prices are assumed to increase from $12/t CO_2e in 2010 to around $34/t CO_2e in 2021, reflecting a gentle emission abatement target in the early years of the proposed carbon pollution reduction scheme.

Commonwealth rebates through the Solar Homes and Communities Plan, currently provided for roof top PV systems are assumed to be provided from 2008 to 2010 only (no rebates are assumed to be provided after 2010).

3.4 Other revenues

Small scale renewable generators were also assumed to earn revenue from sale of renewable energy certificates. An average system was assumed to be deemed to earn 2 certificates each year over a 15 year period, with the value of each REC assumed to earn $40/MWh.

In addition, it is assumed that some customer groups were willing to adopt PV systems at above the equivalent cost of grid supplied electricity (that is, some installations will occur even without being costs competitive). The value of this premium was assumed to be around $2,000[11]. This applied to additional cumulative systems installed in Victoria of 8,000, after which no premium was applied.

[11] This was estimated by adjusting the premium in our distriubted generation simulation model until historical sale numbers in 2006/07 aand 2007/08 are achieved. That is, a premium of $2000 is required for the simulation model to achieve recent sales levels.

4 IMPACTS

The modelled results are discussed below. As stated above, the results are indicative of the range of costs and benefits from the policy options.

4.1 Uptake levels

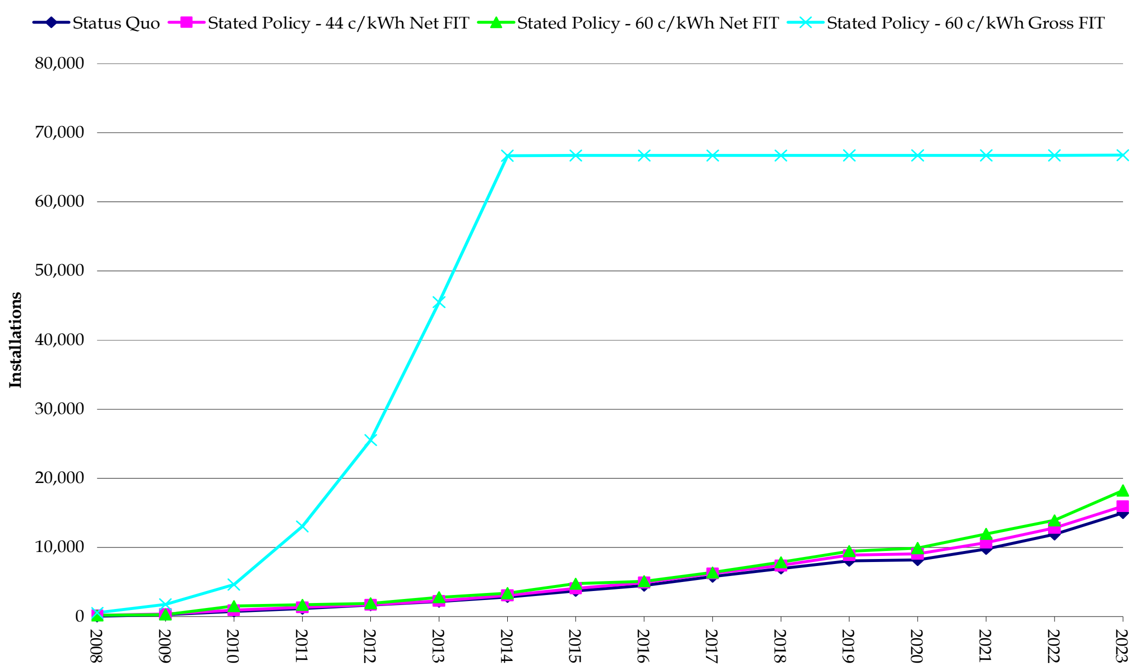
4.1.1 Photovoltaic generation

The forecast uptake of photovoltaic systems is shown in Figure 4-1. The uptake of PV is displayed in terms of generation and as cumulative capacity in Figure 4-2 and Figure 4-3 respectively.

Rapid uptake of PV systems is evident after 2020, resulting primarily from the reduction in the cost of the PV systems, makes them close to economic generation options. In the net feed in tariff scenarios, uptake is less than 10,000 units (less than 0.3% of all households). By 2023, uptake roughly doubles in these scenarios to 20,000 units. The stated policy scenario with 60 c/kWh net tariff has the highest uptake of the net tariff scenarios.

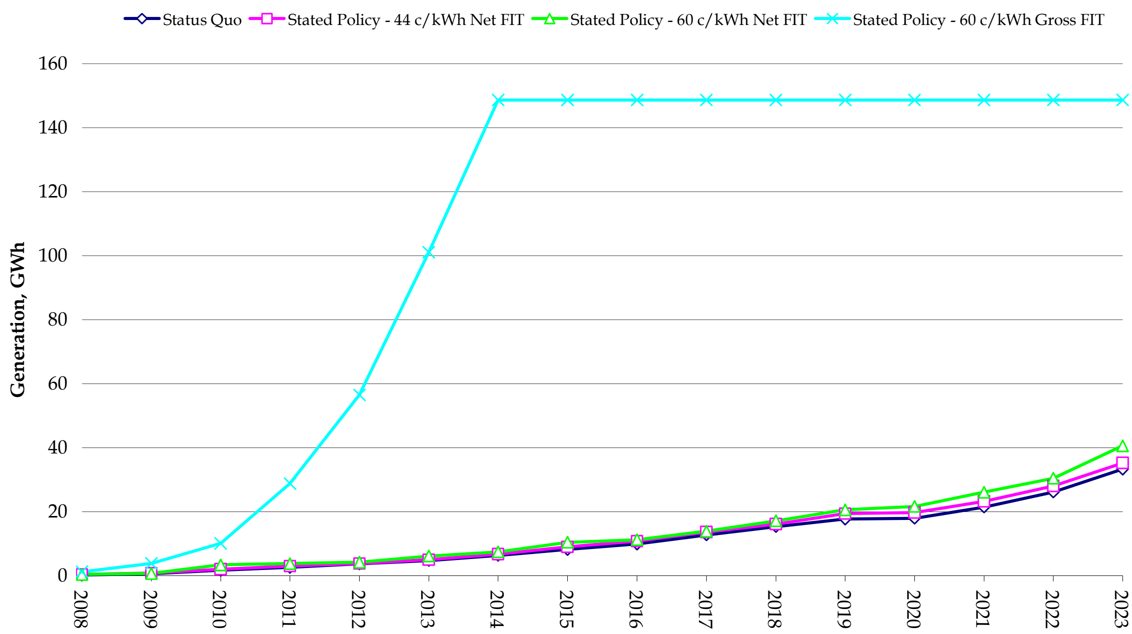
Only in the scenario with the 60 c/kWh gross tariff does significant uptake of PV systems occur prior to 2020. In the 60 c/kWh gross tariff case over 60,000 systems are installed by 2015 compared to less than one tenth this number for all of the other scenarios, which never reach the maximum level of capacity mandated under the policy. The increase in installed numbers post 2020 is largely independent of the level of tariff applied and is a result of the declining costs of PV systems which makes a portion of the installation economic regardless of the level of support. In the gross tariff scenario uptake will be significantly higher if the 100 MW cap was removed.

Figure 4-1 Cumulative number of installed photovoltaic systems



Similarly in terms of the electricity generation resulting from PV systems, only the 60 c/kWh gross tariff scenario results in significant generation in the medium term, reaching 150 GWh in 2015. In terms of the impact on the total electricity supply system this represents 0.40% of the forecast demand in Victoria in 2015 and 0.30% of the forecast demand in 2023[12]. All the other scenarios result in generation representing less than 0.03% of total demand in 2015 and less than 0.10% in 2023.

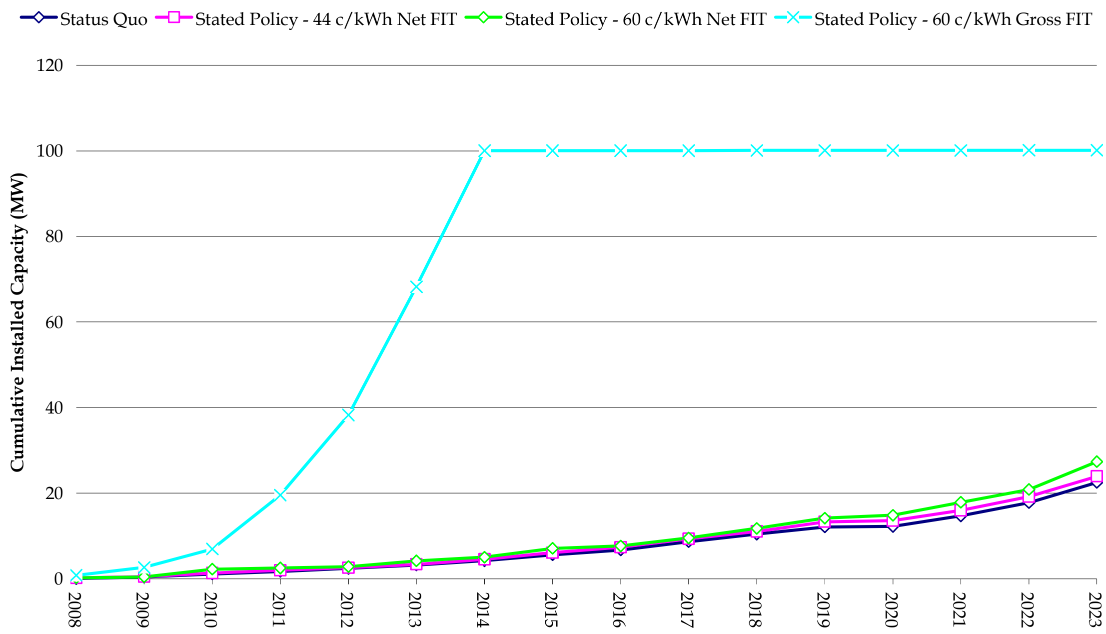
Figure 4-2: Photovoltaic generation (GWh/year)



The installed capacity in MW of PV systems is shown in Figure 4-3 and shows that the premium gross tariff would encourage the installation of about 100 MW of PV systems by 2015, stalling at this level due to the cap imposed under the policy. In comparison the net metered tariff scenarios result in capacity of less than 20 MW by 2015 and around 30 MW by 2023. This compares with the standard size of a new gas turbine of around 160 MW and average rate of growth in peak demand of around 150 MW, implying that even with the gross tariff of 60 c/kWh there would not be enough capacity installed to defer the need for new fossil fuel generation capacity by longer than one year.

12 Estimates of electricity supply are on a sent out basis for the major electricity grids only

Figure 4-3 Installed photovoltaic capacity (MW)



4.2 Benefits and costs

As discussed in Section 2, a feed-in-tariff can be justified on the grounds that there are some market failures in existence that prevent an optimal uptake of small scale generation. Before Government action can be justified, however, an analysis of the benefits and costs needs to be undertaken. This section presents the results of the benefits and costs.

4.2.1 Resource costs

Higher generation costs will be incurred with renewable small scale generation as the unit capital costs are significantly higher than for new large scale centrally dispatched generating plant. Further, to the extent that new small scale generation displaces generation form existing plant, then only the variable cost of existing plant are avoided (as capital cost of these plant are sunk).

Estimates of the additional cost of generation as an average of the period from 2008 to 2023 are contained in Table 4-1. The additional cost ranges from $0.03/MWh to $1.91/MWh averaged across residential customers. This equates to an average increase in resource costs over the period from 2008 to 2023 of between 0.03% and 3.3%.

Table 4-1 Costs of FIT compared with status quo

	Stated Policy - 44 c/kWh Net FIT	Stated Policy - 60 c/kWh Net FIT	Stated Policy - 60 c/kWh Gross FIT
Cost, $M	7	18	726
Average cost impost, c/kWh	0.0031	0.0141	0.1191
Average increase in supply costs, %	0.03%	0.08%	3.34%

Note: The cost in $M is equal to the present value of the additional resource costs (capital, fuel and operating costs) involved in electricity supply. The present value is calculated for the costs in the period 2008 to 2023 using a social discount rate of 7% (in real terms). Source: MMA analysis

Some care should be taken in interpreting these cost estimates. The estimates do not include any distribution and transmission cost savings apart from a minor deferment of a regional transmission upgrade. However, any savings is likely to be very small given the small uptake of small scale generation. Further, the costs increases are likely to be lower because the estimates only consider costs to 2023. As there is considerable uptake in the period from 2020, the benefit of this uptake in terms of reduced fuel and operating costs from centrally dispatched generation beyond 2023 is not taken into account.

4.2.2 Benefits

The installation of the small scale generation makes a significant impact on greenhouse gas emissions. The quantities of greenhouse gas emissions avoided due to the scenarios are shown in Figure 4-4 and Figure 4-5. The charts shows the relatively small contribution of the scheme when net metered tariffs are employed. The 60 c/kWh gross tariff results in a total abatement over the period from 2008 to 2023 of 2.2 Mt CO_2e, and an ongoing mitigation of about 0.16 Mt per annum after this period. The net scenarios, by contrast, results in total abatement over the period to 2023 of around 0.3 Mt CO_2e, with net annual savings in emissions peaking at 0.05 Mt CO_2e in 2023.

The emission reductions in the final year will continue into the future until the equipment no longer functions or is replaced. This would be at least 10 years in the majority of installations.

Figure 4-4 Greenhouse gas emissions abated, 2008 to 2023

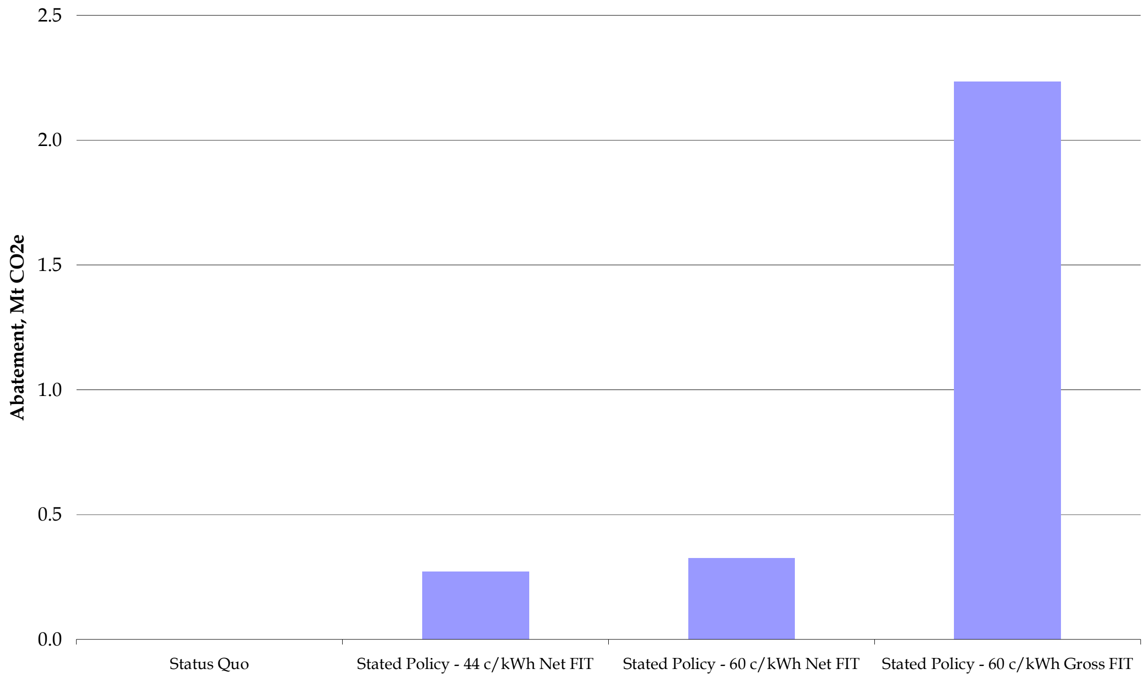


Figure 4-5 Annual average abatement over the period from 2008 to 2023

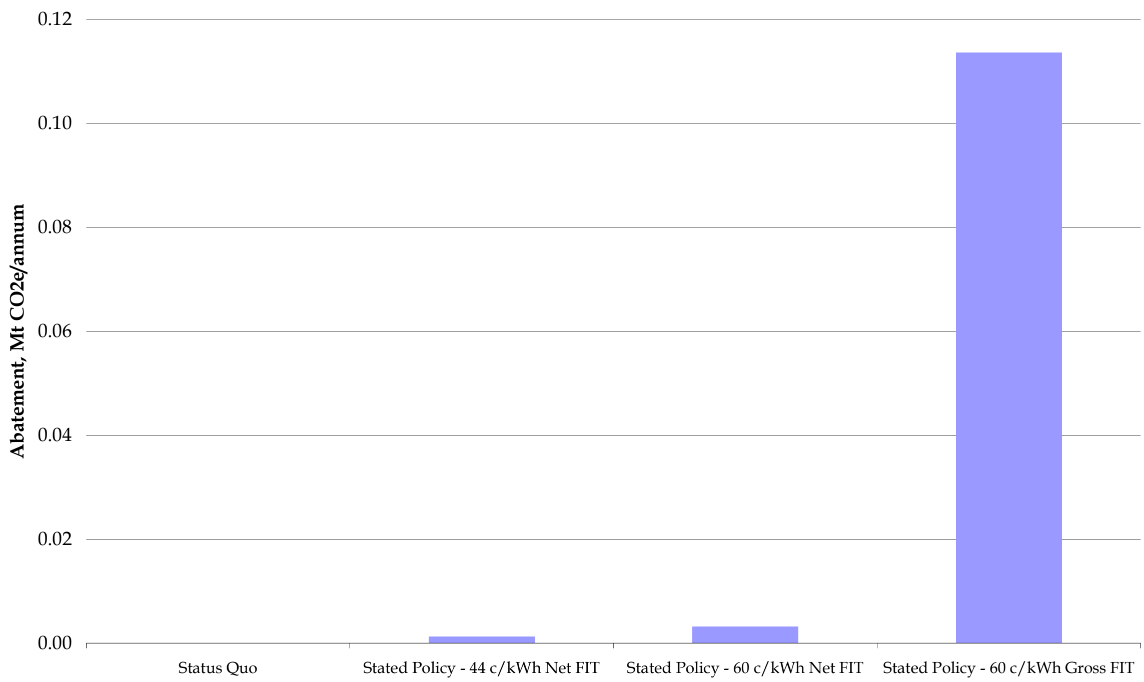
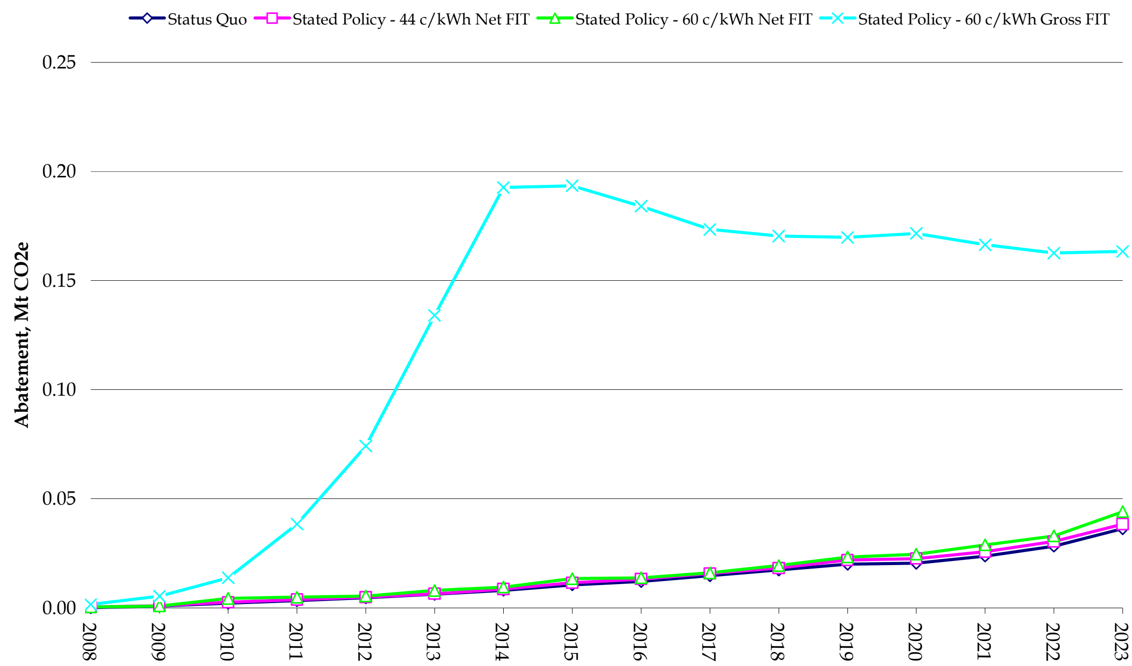


Figure 4-6 Annual Abatement (Mt CO_2e/year)



The cost effectiveness ($ of additional resource cost per tonne of abatement) of the policy is as follows:

- $62/t CO_2e for the stated policy with net FIT of 44 c/kWh.
- $138/t CO_2e for the stated policy with net FIT of 60 c/kWh.
- $679/t CO_2e for the stated policy with gross FIT of 60 c/kWh.

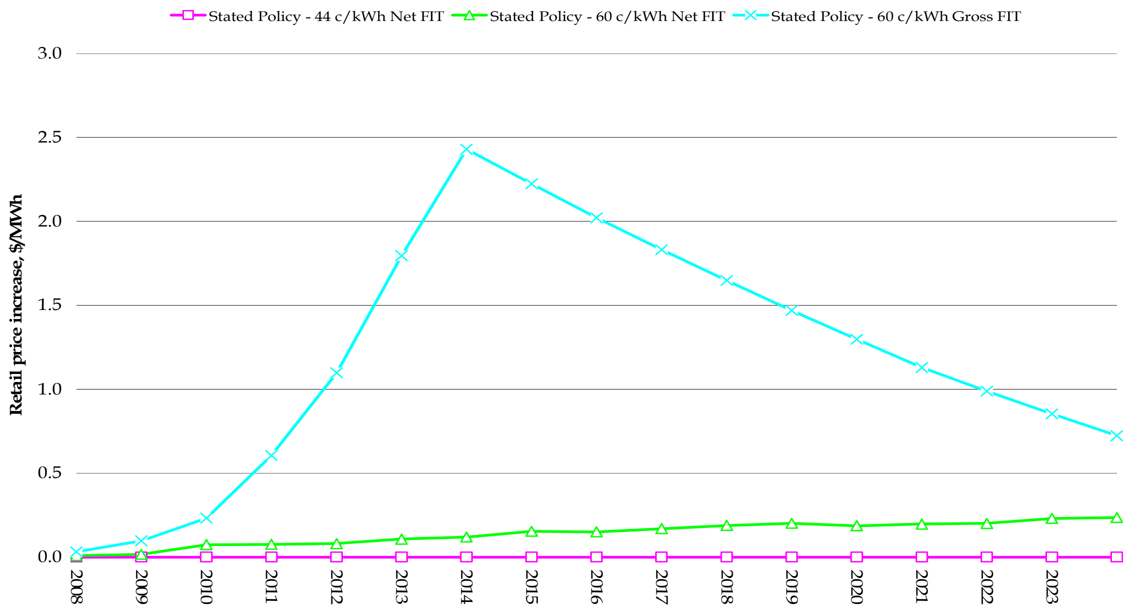
Care needs to be taken in interpreting these numbers as they do not include the ongoing benefits nor savings in system costs from further emissions from 2023 onwards (even if the costs of adopting the system is included).

4.3 Other impacts

4.3.1 Retail prices

The percentage increase in residential retail tariffs over the duration of the scheme is shown in Figure 4-7 for the four main scenarios. As would be expected all of the net metered scenarios result in minimal impact on the residential retail prices over the period of the scheme, with annual retail prices increasing by less than $0.3/MWh (or by less than 0.5% increase in retail tariffs). This is a result of both relatively low uptake and only a fraction of the generation being eligible for the FIT tariff. In the case of the gross tariff, the residential retail electricity price is estimated to increase by 2.5% by 2015, and then declines as the capacity limit is reached (so that no more PV systems are installed and the feed in tariff declines in real terms). The cost of scheme could be either passed through to the customers either by retailer or distributor with little difference, but where the cost is passed through it results in a relatively small increase in the cost of electricity over the period.

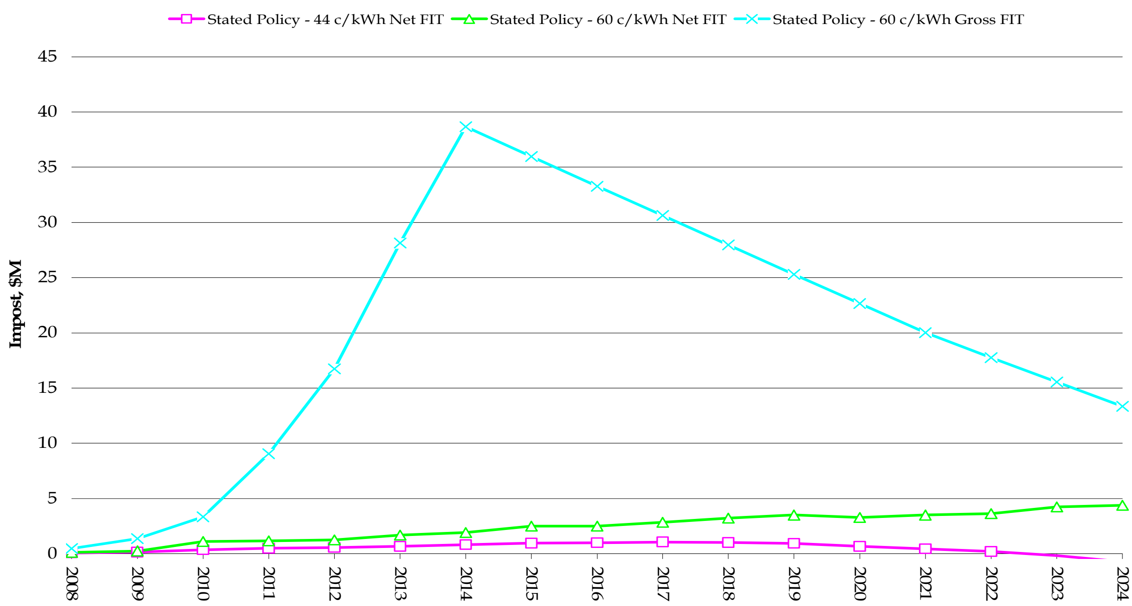
Figure 4-7 Increase in residential retail tariffs



The increase in residential retail electricity prices resulting from the implementation of feed in tariffs according to the key scenarios are shown in Note: Calculated as the difference between prescribed feed in tariff minus the rates a PV roof top generator would have received (assumed to be equivalent to the status quo rates) times the level of eligible PV generation.

Figure 4-9 assuming that the impost is passed through to residential customers only. These data show that relatively small increases in electricity prices would occur even where the cost is spread over a small number of customers.

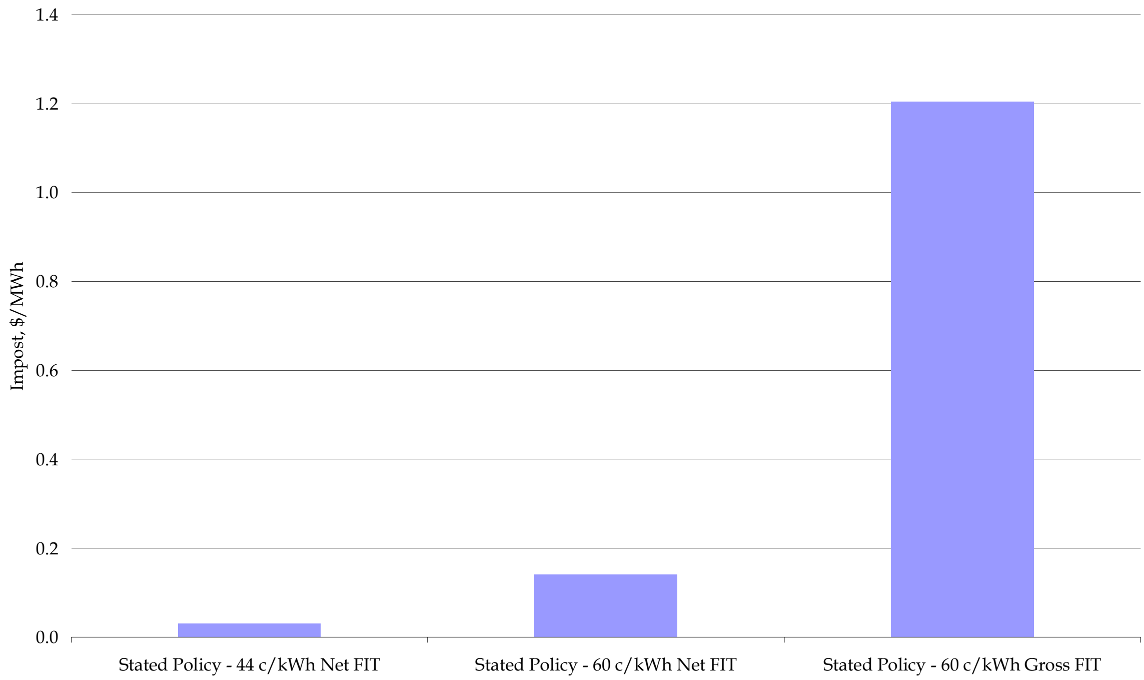
Figure 4-8 Increase in electricity purchase costs



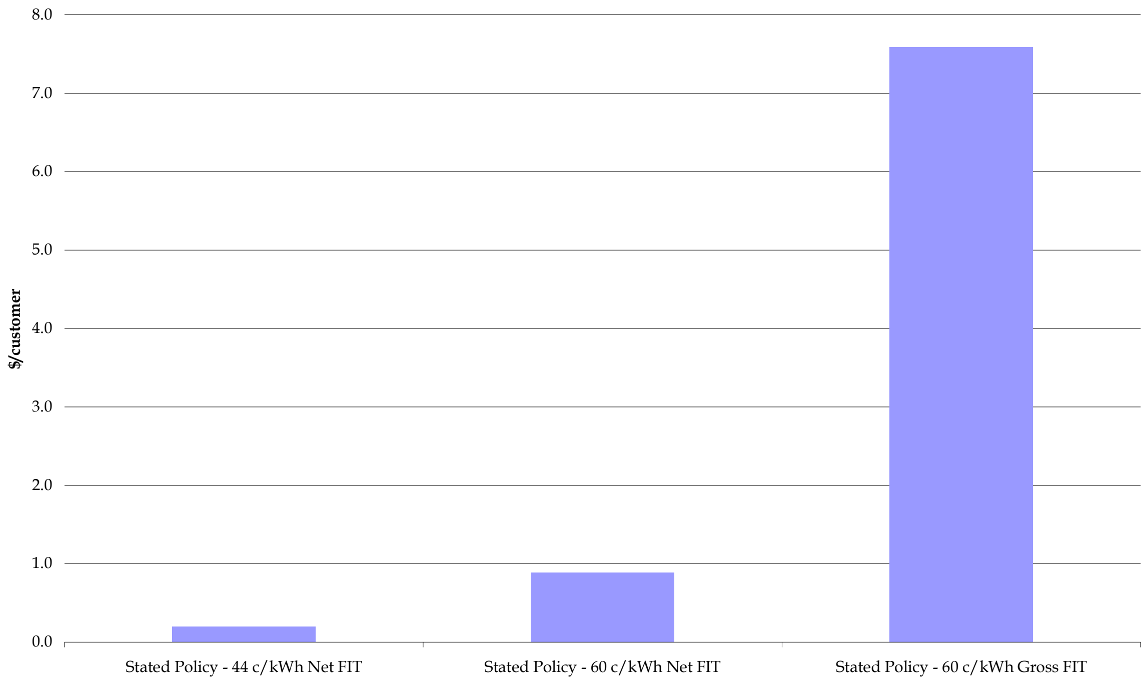
Note: Calculated as the difference between prescribed feed in tariff minus the rates a PV roof top generator would have received (assumed to be equivalent to the status quo rates) times the level of eligible PV generation.

Figure 4-9 Increase in Average Retail Price, 2008 - 2023

(a) $/MWh

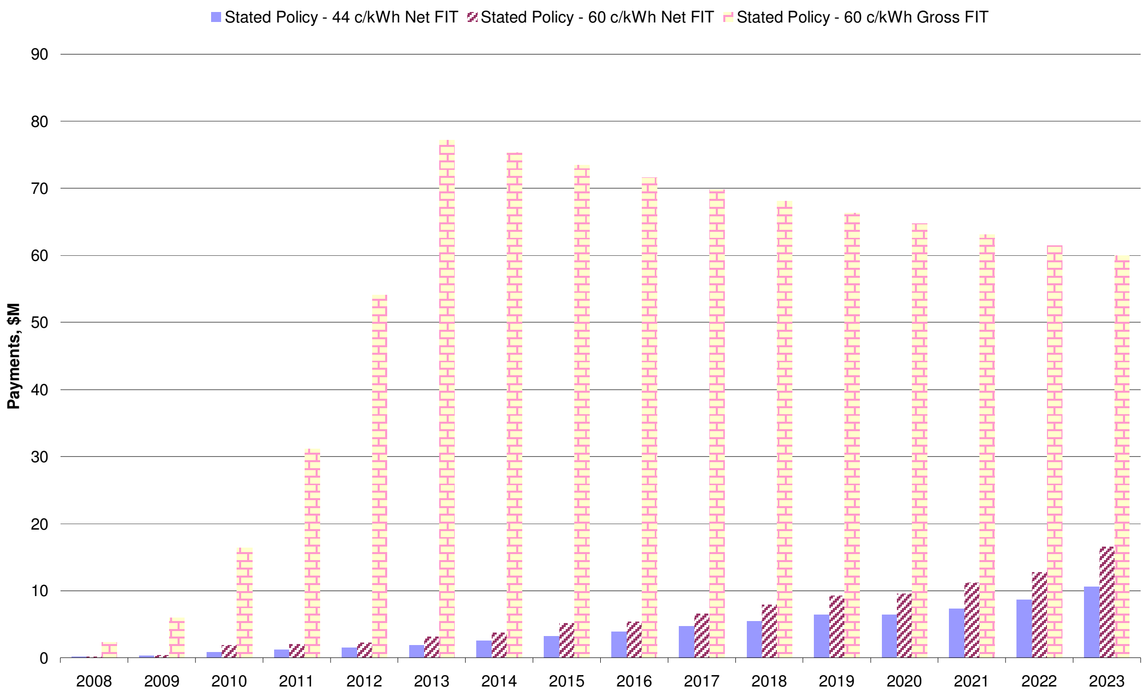


(b) $/customer/year



Total payments to householders with PV systems are shown in the following chart. Under the stated policy with a net FIT, payments reach just over $15 million per annum by 2023, with an average annual payment of $6 million. This compares to an average annual payment of $54 million to households with PV under a gross tariff of 60 c/kWh and $4 million under a net 44 c/kWh tariff.

Figure 4-10: Payments under the FIT to households with PV systems



Some households would also benefit by receiving the Solar Homes and Communities Plan Rebate. The following table shows the number of households receiving this rebate over the next few years.

Table 4-2: Number of households receiving Commonwealth rebate for roof top PVs

	2009	2010
Status quo	245	493
Stated Policy - 44 c/kWh Net FIT	382	596
Stated Policy - 60 c/kWh Net FIT	421	1,266
Stated Policy - 60 c/kWh Gross FIT	1,641	2,894

4.4 Sensitivity analysis on system costs

Uptake depends critically on a number of key assumptions, mainly assumptions on the capital costs of PV systems, the cap on capacity imposed the willingness of consumers to pay extra for PV systems and the level of the feed-in-tariff. Additional sensitivity analysis was performed around the Stated Policy Scenario with a 60 c/kWh Net FIT. The sensitivities performed where:

- Lower capital costs. In this sensitivity, capital costs for PV systems were decreased by 7% per annum (instead of 5% per annum). This rate of decline reflects the high estimates of the learning by doing rates published by the IEA.
- Higher willingness to pay. In this sensitivity, the premium people are prepared to pay for a PV system was increased from $2,000 to $3,000 per system. The maximum number of people willing to pay a premium was increased from 8,000 to 36,000.
- Commonwealth Solar Homes and Community Plan PV rebate policy continues. Instead of expiring at the end of 2010, this sensitivity assumed that the rebate continues until the end of 2023, at a rate of $8,000 per system. There is no means test.
- Low export amount. In this sensitivity, only 20% of PV generation was assumed to be exported (instead of 30%).

Key results for the sensitivities are shown in the following table. The analysis indicates that:

- Outcomes are highly sensitive to factors that reduce the installed cost of PV systems. In particular, lower capital costs and extending the Commonwealth Solar Homes and Communities rebates have marked impacts, leading to higher adoption rates equivalent to the 60 c/kWh gross tariff scenario.
- Uptake and costs to the community, as well as abatement benefits, are lower the lower the assumed proportion of net exports from PV systems. Imposts on residential customers from the FIT ranges from $2.63/cuctomer/year with lower capital costs, $0.76/cuctomer/year with higher willingness to pay, $1.46/cuctomer/year with extension of the PVRP, and $0.70/cuctomer/year with lower net exports.

Table 4-3: Sensitivity results showing differences from Stated Policy Net 60 c/kWh Tariff Scenario

Sensitivity	Lower capital costs		Higher willingness to pay		Commonwealth rebate continues		Lower exports	
	2010	2020	2010	2020	2010	2020	2010	2020
PV generation, GWh	4	151	3	22	3	44	1	22
PV Capacity, MW	3	100	2	15	2	31	1	15
PV systems installed	1,688	66,594[13]	1,530	10,101	1,507	20,527	462	10,026
Impost, $M	1	23	1	3	1	7	0	3
Retail price increase, $/MWh	0.1	1.3	0.1	0.2	0.1	0.4	0.0	0.2
Resource cost, $M	2	120	2	4	2	24	0	4

[13] Note the 100 MW cap limit prevents in even higher uptake in this scenario. The 100 MW cap reached in 2020.

Abatement, Mt CO2e	0.00	0.17	0.00	0.03	0.00	0.05	0.00	0.02

As can be seen from the following charts, the impacts of each sensitivity can be summarised as follows. Lower capital cost can lead to a large uptake over the long term. Decreasing capital costs by 2 percentage points more per annum leads to a large uptake from 2015 onwards, with the result that the capacity of 100 MW is reached and prevents further uptake. The higher uptake leads to average abatement of around 0.5 Mt per annum, with annual abatement reaching the same level as the gross stated tariff scenario in 2020. The average compliance cost over the 15 year period to all customers increases from $0.1/MWh to $0.5/MWh, but is still half the average for the gross tariff case.

Higher willingness to pay and lower net exports only lead to modest changes to uptake, and therefore do not alter the impacts substantially. Lower net exports does not have much of an impact as although the amount of generation earning the FIT is smaller, the difference is marginal as household consumption of energy is still seen as avoiding delivered energy costs (even if at a lower rate of $200/MWh). Willingness to pay would have to effectively double from the $3,000 premium assumed in the base scenarios for this to have any affect on uptake. Clearly more information is required on customers' willingness to pay for PV systems.

Extending the Commonwealth Solar Homes and Communities rebate also assists in increasing uptake as it acts to reduce the capital costs of the system. Uptake would be higher still than shown except for the assumptions that there is a budgetary limit on how many systems are funded (equal to current annual budget allocations).

One conclusion from this analysis is that the liabilities under the proposed FIT are sensitive to any factor that reduces the capital costs seen by potential purchasers of PV systems, even with a net tariff. This potential increased liability is limited by the 100 MW cap that applies.

Figure 4-11: Sensitivity of generation from PV systems, stated policy with 60 $/MWh net FIT , GWh

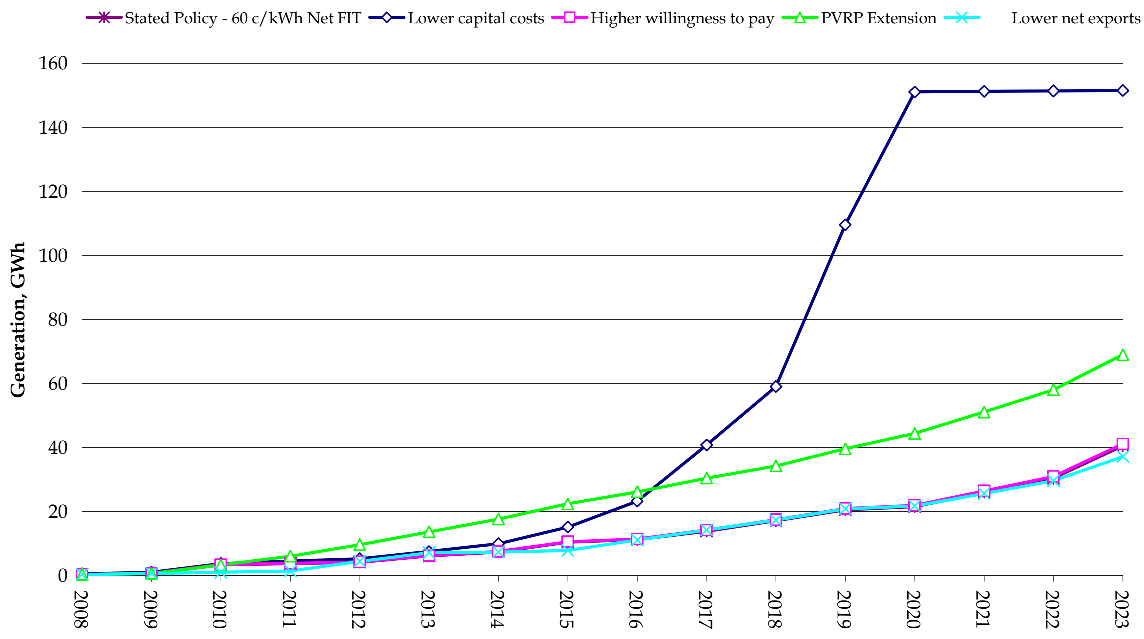


Figure 4-12: Capacity installed, stated policy with 60 $/MWh net FIT, MW

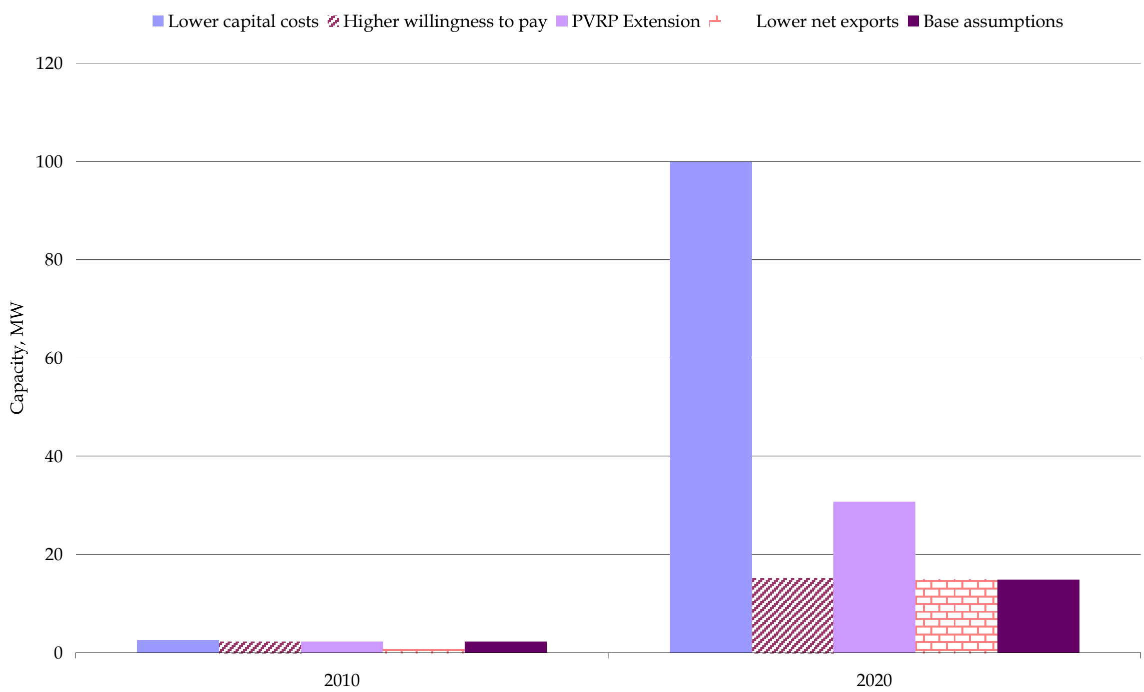


Figure 4-13: Abatement sensitivity, stated policy with 60 $/MWh net FIT, Mt CO_2e

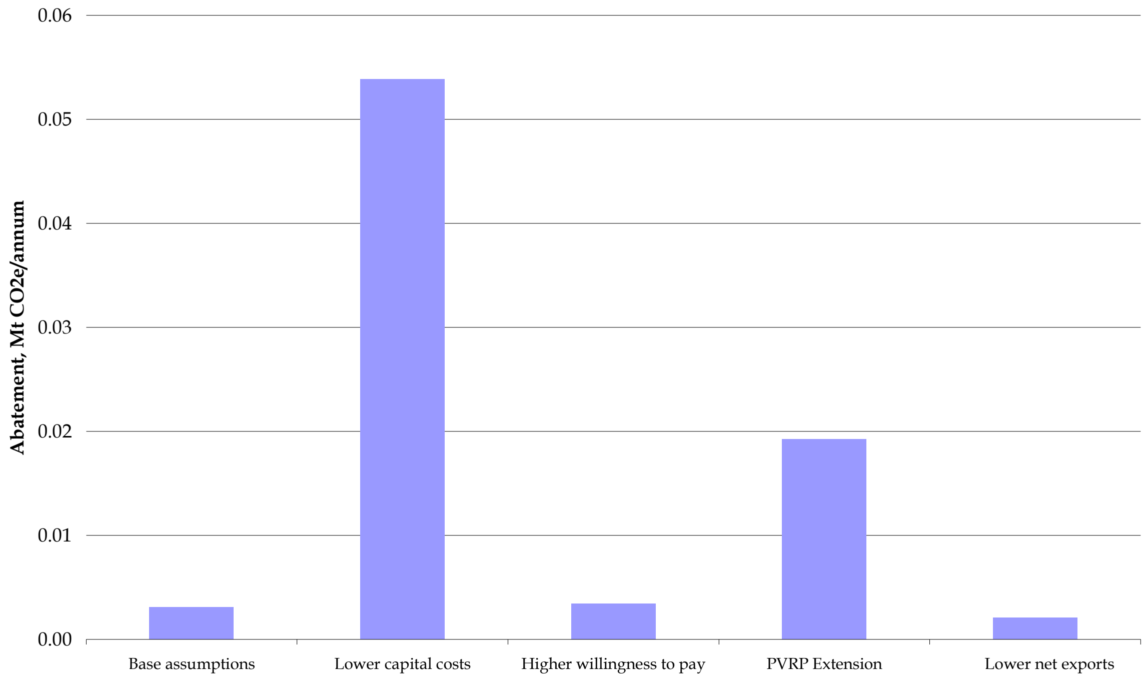
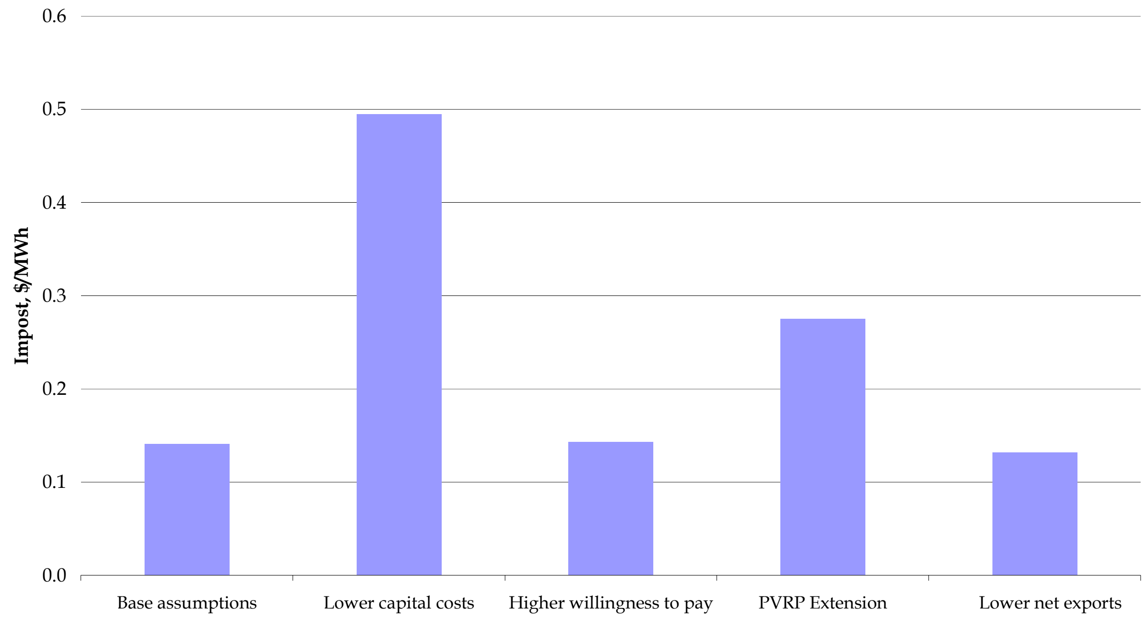


Figure 4-14: Sensitivity of average impost on customers of the stated policy with 60 $/MWh net FIT, $/MWh



4.5 Sensitivity analysis on eligibility criteria

Additional sensitivities were also performed on scheme design parameters as follows:

- Extending coverage to PV systems up to 3 kW. Where net exports applied, the net export amount was assumed to be 40%
- Extending coverage to PV systems up to 5 kW. This extended coverage to farm enterprises (previously assumed to be part of the commercial sector). Where net exports applied, the net export amount was assumed to be 70%.
- Extending eligibility to charities. There is no precise definition of charities and there is limited data on the number of charities, but it was assumed that charities comprised 1% of total commercial demand for electricity.

A summary of the results are in the following table for the stated policy scenario. The sensitivities were also performed on the other scenarios. There was little change in the 44 c/kWh tariff and status quo scenarios. There was also little change for the Gross 60 c/kWh scenario due to the fact that of the 100 MW cap being breached. Significant impacts would have occurred in this scenario if the cap was not imposed.

Table 4-4: Sensitivity results showing differences from Stated Policy Net 60 c/kWh Tariff Scenario

Sensitivity	System Cap of 3 kW		System Cap of 5 kW		Charities included	
	2010	2020	2010	2020	2010	2020
PV generation, GWh	5	33	4	44	3	22
PV Capacity, MW	3	23	2	30	2	15
PV systems installed	1,647	11,406	1,295	11,350	1,525	10,024
Impost, $M	2	5	1	7	1	3
Retail price increase, $/MWh	0.1	0.3	0.1	0.4	0.1	0.2
Resource cost, $M	3	14	2	23	2	4
Abatement, Mt CO2e	0.01	0.04	0.00	0.05	0.00	0.02

APPENDIX A DETAILED SCENARIO DESCRIPTIONS

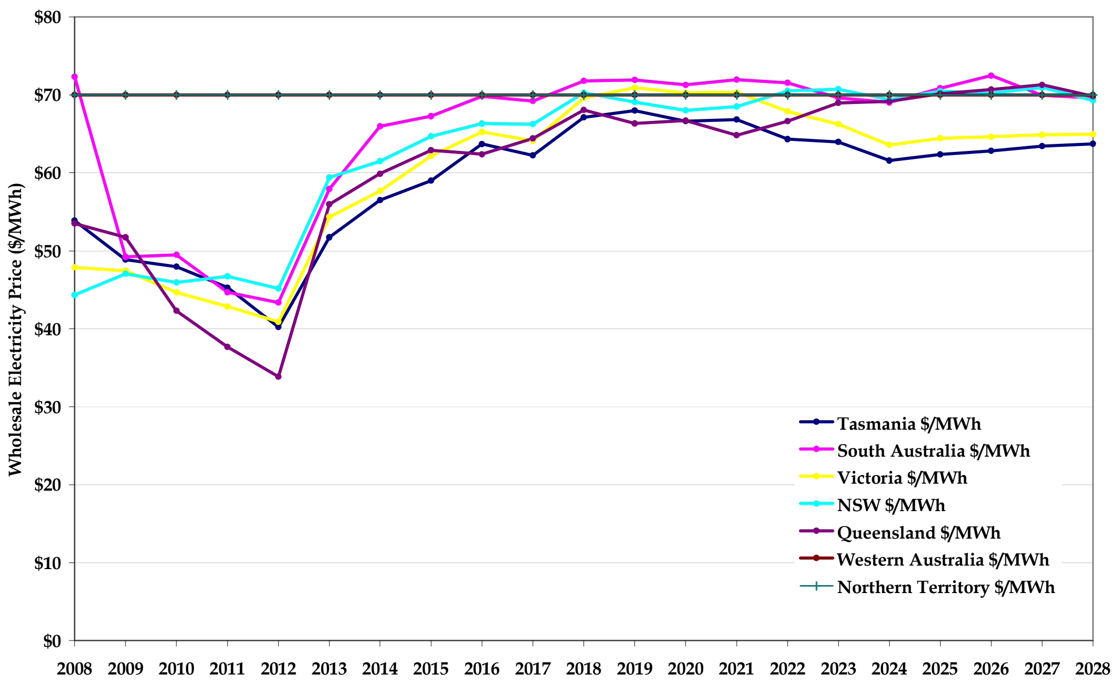
A.1.1 Electricity Demand

Business as usual electricity demand based on the 2007 NEMMCO Statement of Opportunities demand forecast. This demand forecast provides demand as sent out by the power stations, excluding embedded or large scale distributed generation. This data has been adjusted to account for transmission and distribution losses on the network to determine the demand at the residential level.

A.1.2 Electricity Prices

Wholesale electricity prices for the period to 2028 have been obtained from MMA's existing NEM modelling, and are shown in Figure A-1. The wholesale prices are referenced to the regional reference node and have been adjusted for losses to give the wholesale prices at each of the regional centres considered in the modelling and for the pattern of hourly demand by residential and small business customer classes.

Figure A-1 Wholesale Regional Electricity Prices, time weighted average ($/MWh)



At each of the regions modelled the retail price has been determined by the addition of:

- Transmission charges
- Distribution charges
- Retailer margins
- A carbon penalty based on State based carbon intensity.

These charges in total add more than 100% to the wholesale price to result in the retail price. It is this retail price that any distributed generation must compete with.

A.1.3 Interval Meters

Interval meters allow charging for electricity at a price that more effectively represents its value, by charging different rates depending on when the power is used. Their introduction has an important impact on the installation of distributed generation in that it also provides the possibility of being paid for exports to the grid at time dependent prices. Photovoltaic cells in particular generate the most electricity during peak times when prices are higher. If the price paid for the exported power is related to the time of generation significantly higher rates would be available than those from average monthly billing. We have estimated the interval metering electricity price for PV and wind generators using available time of day output data for these technologies and hourly electricity prices to approximate the price that would be available under these circumstances.

We have assumed that total installations of interval meters will reach 10% of households by 2010 and then increase by 10% per year until 2019 when it is assumed that all dwellings will have interval meters installed[14]. The prices received for exported electricity have been determined using this fraction of installed meters and the generation weighted average retail prices.

A.1.4 Climate Change Policy

Announced policies including expanded MRET and an emission trading scheme have been included by the incorporation of an implied carbon tax. The rate of the carbon tax to 2020 is shown in Table A- 1. The carbon tax included as an additional cost assigned to fossil fuel burning generation according to the carbon intensity of the fuel.

Table A- 1 Carbon Tax Rate ($/tonne CO_{2e})

	2008	2009	2010	2011	2012	2013	2014
Carbon Price ($/tonne CO2e)	$0	$0	$12	$13	$15	$16	$18
Carbon Price ($/tonne CO2e)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021-2030**
	$19	$21	$23	$26	$28	$31	$34

A.2 Restrictions on Installations

The absolute number of installations of the renewable generation systems is limited by a number of factors including:

- Availability of the renewable resource

14 Arecent communique by the MCE recognises that roll out dates will differ, with the likely completeion dates of 2017 in Victoria and NSW. Other states will follow after review of business cases for the roll out. Minister Ferguson also stated that “it is expected that by 2017, on the basis of this rollout, over half of Australian meters will be replaced by smart meters”

- Limitations in supplying sufficient quantities of equipment
- Locational and planning restrictions, particularly with wind turbines, where it is unlikely approval would be given in densely populated areas.

To account for these restrictions in model we have assigned maximum percentages of the total load that could be supplied by each technology in each year. Separate percentages have been applied to metropolitan and rural regions to differentiate between the significant differences between these regions. The restrictions on installation in each year utilised in the modelling are detailed in Table A-2. These restrictions may be seen as conservative.

Table A-2 Restrictions on annual installation of generating technologies (% of total region load/year)

Technology	Metropolitan	Rural
Photovoltaic	0.1% - 0.5%	0.1% - 0.5%
Mini Wind	0.001% - 0.005%	0.02% - 0.5%
Mini-Hydro	0%	0.0001%

Restrictions on annual installations designed to fit in with current installed manufacturing capacity. These restrictions did not typically constrain uptake in the model simulations except in some regions for the gross 60 c/kWh FIT scenario.

A.3 Feed in Tariffs

The Feed in Tariff is additional payment to owners of distributed generators for the electricity generated. These programs aim to assist the generation technologies achieve volume manufacturing rates and approach economic viability. The FIT may be applied in one of two main ways:

- Net metering: The tariff is paid on actual export to the grid, which is equivalent to the generation minus any household load of a predefined interval.
- Gross metering: The tariff is paid on the basis of the quantity of electricity generated, regardless of household use or actual exports to the grid.

Both methods have advantages and disadvantages, although in Australia much of the focus is on net metering.

The scenarios we have examined are mostly on a net metered basis, with one scenario examining the gross metered basis.

The introduction of net metering complicates the modelling exercise by the requirement to estimate a suitable value for the fraction of energy that is exported from the total unit generation. The fraction exported may vary between 25% and 50% according to household load and size of generating unit, according to a recent SA study. It has been reported that the 1 kW systems installed in the Newington Village (former Olympic village in Sydney) have recorded export of just over 40% of output. We have assumed a conservative level of 30% exported in all the scenarios. It should be noted that a net or gross feed-in tariff may increase the size of PV installations to maximise the subsidy, and this impact has not been considered in this study.

The FIT may also be applied as:

- A set rate based on the year of installation that applies for a defined period from the date of installation, resulting in many different rates as the program progresses. This best reflects the actual costs incurred by the installer.
- A an annually defined rate each year that declines as the program proceeds, resulting in a single tariff at any one time regardless of the installation date.

The second method may be simpler administratively but does not reward the earlier installers for the additional costs they incur compared to the later installers. Neither option has been examined in this study.