QUEENSLAND PRODUCTIVITY COMMISSION

FINAL REPORT

SOLAR FEED-IN PRICING IN QUEENSLAND

June 2016

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THE ROLE OF THE QPC

The Queensland Productivity Commission (QPC) provides independent advice on complex economic and regulatory issues, and proposes policy reforms, with the goal of increasing productivity, driving economic growth and improving living standards in Queensland. Wide-ranging, open and transparent public consultation underpin these functions.

The QPC is an independent statutory body established under the *Queensland Productivity Commission Act 2015.*

Our work encompasses four key streams:

- public inquiries into matters relating to productivity, economic development and industry in Queensland, as directed by the Treasurer
- advice and research on matters beyond our formal inquiry function
- advice and guidance to departments, including providing independent support and information on the quality of regulatory proposals
- investigation of competitive neutrality complaints about state and local government business activities.

The QPC operates on the principles of independence, rigour, responsiveness, transparency, equity, efficiency and effectiveness.

The QPC operates independently from the Queensland Government — our views, findings and recommendations are based on our own analyses and judgments.

The QPC has an advisory role. This means that we provide independent advice to the government that contributes to the policy development process — but any policy action will ultimately be a matter for the government.

After undertaking a public inquiry, the QPC must prepare a written report and provide it to the Treasurer. The Treasurer must provide the QPC with a written response within six months of receiving it. After that, the QPC must publish the Final Report.

OVERVIEW

Over the last decade, small customer solar photovoltaics (solar PV) has played an increasingly prominent role in energy markets and energy policy.

Solar PV has wide-ranging impacts. It supplies a renewable source of electricity, allows households and businesses to offset electricity costs, brings new technologies and products to consumers and increases competitive pressures in the electricity supply industry. It also represents a large investment for many small customers.

Queensland today has amongst the highest penetration of small-scale solar PV in the world — growing from less than 1600 residential installations in 2007 to more than 450,000 systems by the end of 2015.

Solar PV has formed the centrepiece of a number of state and national policies targeting climate change. The Queensland Government has made a commitment to increase the contribution of renewable energy to Queensland's energy mix, including building on Queensland's world-leading uptake of solar energy.

Within this context, the price paid for electricity generated by solar PV and fed into the grid (solar exports) is important to not only to the owners of solar PV, but also to other residential and business electricity consumers — particularly where solar exports affect electricity prices, either directly or indirectly.

Purpose of the inquiry

In August 2015, the Queensland Government asked the QPC to investigate and report on a fair price (or prices) for solar exports produced by small customers. The terms of reference requires us to assess a wide range of factors, including:

- the public and consumer benefits of exported solar energy, including social, economic and environmental benefits;
- whether solar PV owners are already fairly compensated for public and consumer benefits (such as through renewable energy programs, rebates and market contracts);
- any barriers to monetising the value of exported solar energy in Queensland in the current electricity system, and options to address those barriers;
- how the fair price (or fair prices) may be designed and paid;
- the mechanisms by which a fair price could be implemented (mandatory or other); and
- appropriate review mechanisms and timeframes.

The terms of reference also states that any price for exported solar energy must not impose unreasonable network costs on electricity customers — particularly vulnerable customers.

The coverage of this inquiry is confined to future solar feed-in tariffs. Other policy matters related to renewable energy and environmental programs, including the Solar Bonus Scheme (SBS), are covered by the QPC's Electricity Pricing Inquiry.

A fair price for solar exports

A key part of this inquiry has been to determine what is a fair price for solar exports.

As views are subjective on what constitutes a 'fair' price for solar exports, we have adopted a community-wide approach — that is, a fair price is one that is fair for all Queenslanders. The principle of fairness should apply not only to solar PV owners or electricity businesses, but to all electricity customers and the wider Queensland community.

A price for solar exports will be fair when solar PV owners are receiving an efficient price for the energy they generate — and remaining electricity consumers are not paying more (or less) than they should for solar PV generated energy.

For most goods and services, including solar electricity, the community is best served when competitive markets set prices to their efficient level and drive suppliers to offer the mix and quality of goods and services desired by consumers. In this way, a properly functioning market sets a fair price.

The two main exceptions are where:

- a dominant firm can use its market power to pay feed-in tariffs below competitive levels; and/or
- externalities — such as environmental pollution — are not accounted for in the market.

Are solar PV owners compensated for the energy they produce?

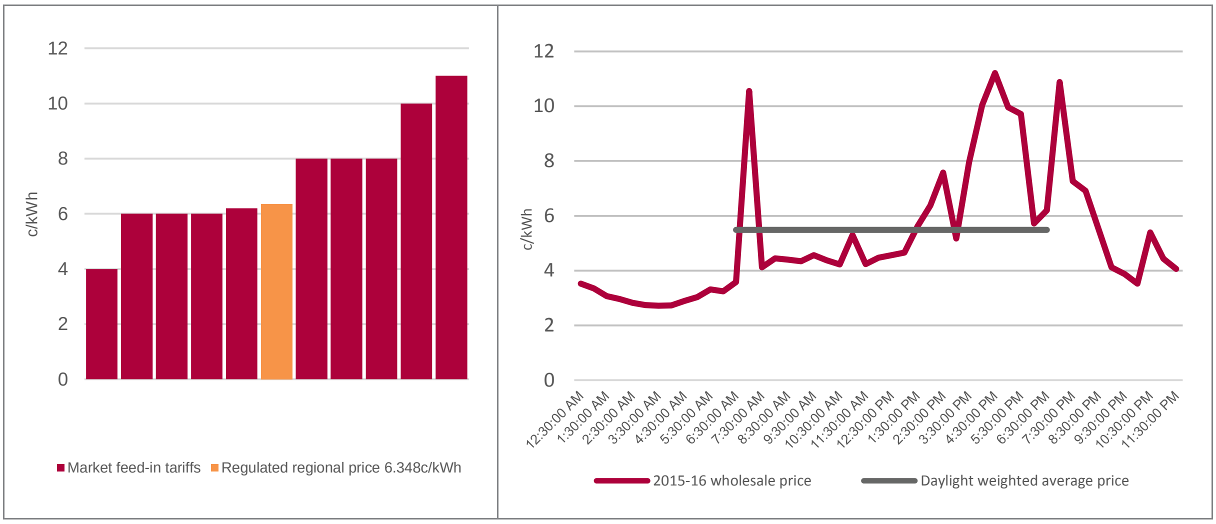
A primary benefit of solar PV exports is the production of electricity that feeds into the grid. In south east Queensland (SEQ), 10 retailers compete for solar export customers through a feed-in tariff, with offers ranging from 4c/kWh to 11c/kWh.

Feed-in tariffs compare favourably with what a solar PV exporter could earn if they were a large generator in the wholesale market. If an average solar PV exporter could sell electricity into the wholesale market, they would have earned 5.49c/kWh in 2015–16 (see Figure 1).

Moreover, feed-in tariffs are now just one of a number of solar products electricity retailers are offering. They have also started to offer a suite of innovative products, including solar power purchase agreements (SPPAs), which are long-term agreements that offer installation of solar panels (and potentially batteries) at zero up-front cost. For some of these products, there is no explicit price for solar exports and electricity is purchased at a rate below the retail rate; for others there is a feed-in tariff of 12c/kWh–20c/kWh.

The level of retail competition in SEQ appears effective in delivering a range of feed-in tariffs and other options for solar PV consumers — and is providing a fair price for solar exports. Looking ahead, competitive pressures are likely to increase further as the number of market participants and smaller retailers continue to grow, new service providers enter the market, and solar PV panels become cheaper.

Figure 1: Feed-in tariff offers and time-of-export wholesale prices in 2015–16



Note: The 2015–16 wholesale price is until 23 February 2016.

In regional areas, government-owned Ergon Energy (Retail) continues to be the dominant electricity retailer due to the Queensland Government's Uniform Tariff Policy (UTP).

Ergon Energy (Retail) sells electricity to 97 per cent of small customers in regional Queensland, and by any traditional measure it possesses market power. A retailer with significant market power is not exposed to the same market pressures to provide a competitive feed-in tariff as retailers in a competitive market.

Although there are some disciplines on Ergon Energy (Retail), the lack of retail competition indicates some form of regulation for solar export pricing is warranted in regional Queensland.

Are environmental benefits accounted for?

Solar PV reduces emissions from electricity generation, primarily by displacing electricity that would otherwise have been generated from fossil fuel sources. If solar PV generates environmental benefits that are not being recognised through existing programs, then solar PV owners will not be compensated for the benefits they provide.

Investors in solar PV receive a subsidy from the national Small-scale Renewable Energy Scheme (SRES). The SRES reduces the up-front cost of purchasing and installing a solar PV system by around 30–40 per cent on average. Based on average solar PV system prices, the level of the SRES subsidy is between 2.8 and 2.9c/kWh generated, or around 7.1c/kWh in terms of energy exported.

An additional payment would achieve relatively low emissions abatement at high cost:

- More than 85 per cent of the subsidy would go towards increasing the financial returns to solar PV owners, rather than inducing additional solar PV generation; and
- Under the most likely scenario, the cost of reducing emissions is $268–$327 per tonne of abatement or $363–$422 per tonne including the SRES.

Are there other benefits that should be reflected in a fair solar price?

Other potential impacts, such as solar industry development, lower wholesale electricity prices, lower network expenditure and social benefits, were examined to assess whether they should be included in a price for solar exports. We concluded that, while solar PV has many direct and indirect positive impacts (as well as costs), this does not create a case for higher (or lower) feed-in tariffs:

- *Industry development and job creation* — Mandating solar feed-in tariffs to induce solar industry development and employment will be paid for by other consumers. Subsidising solar exports for industry development reasons will increase electricity costs for other businesses and households (including the least well-off consumers) and is likely to have an overall negative impact.
- *Generation costs and wholesale market impacts* — Solar PV has raised the cost of generating electricity in Queensland, with the estimated additional cost in the order of $75–$150 million in 2015. However, as the price of solar PV continues to decline, so will the additional generation costs due to solar PV.

  Solar PV owners should not be paid for any impact on wholesale prices. Governments do not reward generators for reducing the wholesale price, just as suppliers in other markets are not paid for increasing supply. Paying solar PV owners for any reduction in wholesale market prices would likely result in overall higher electricity prices for Queensland consumers.
- *Network costs* — Solar PV may be able to defer network expenditure depending on specific location, penetration level and load characteristics. However, analysis of network data has not identified material network savings from solar PV in Queensland, and to the extent that savings may arise from 2015 to 2020, they are unlikely to outweigh the additional costs incurred from integrating solar PV into the network.
  - From 2015–16 to 2019–20, Energex and Ergon have identified relatively few network limitations. This is due to subdued economic growth and changes in regulatory standards, rather than increasing solar capacity.
  - Of almost 2100 distribution feeders in Energex's network:
    - only 11 feeders have a forecast network limitation, of which two result from a capacity constraint; and
    - another 11 feeders are being monitored for emerging capacity constraints. Of these feeders, analysis indicates that solar PV has the potential to result in a detectable investment delay on three feeders of one to two years.

    Solar PV has relatively little impact on network constraints because the peak for most assets is either when solar is generating at low capacity or is not generating at all.
  - At the zone substation level, Energex has no forecast limitations over the regulatory period under normal operating conditions, while Ergon has one forecast limitation. A large proportion of both Energex's and Ergon Energy's zone substations peak after 6 pm.
  - Increasing solar penetration is driving network issues that require additional operating expenditure and, in some cases, capital investment. Approved expenditure directly related to solar over the regulatory period amounts to more than $73 million (in real 2014–15 dollars).
- *Social benefits* — We have not identified specific social benefits from solar PV exports that would warrant an increase in the feed-in tariff.

Overall, Queensland solar PV owners are being fairly compensated for public and consumer benefits of solar exports from a combination of renewable energy programs, market contracts in SEQ and the regional feed-in tariff.

Equity considerations

Solar export pricing arrangements that are paid for (either directly or indirectly) by electricity consumers can have adverse impacts, particularly on the least-well off consumers in Queensland.

The existing subsidy to solar PV in Queensland from the SRES, SBS and tariff structures is $597 million in 2015–16. This does not include grants and other national/state programs. Any new subsidy provided through a feed-in tariff would be in addition to this amount.

Modelling shows that solar PV capacity in Queensland is projected to continue its strong growth over the next 20 years without additional intervention. An additional subsidy through a feed-in tariff would increase the rate of investment, although not appreciably.

Table 1 shows the estimated cost of four theoretical feed-in tariff schemes to 2034–35 (on a net present value (NPV) basis), which range from $82 million for a feed-in tariff of 10 cents (real) to $2.3 billion for a feed-in tariff of 10 cents (real) plus the market buyback rate. It also shows the retail price impacts, which are estimated to raise electricity prices by between 1.8 and 8.4 per cent by 2034–35.

Table 1: Cost of above-market feed-in tariffs and impact on retail electricity prices by 2034–35

Feed-in tariff scenario	*Subsidy ($million)*		*Increase in retail electricity prices*
	0% discount rate	*6% discount rate*	
10 cents real	$56	$82	1.8%
15 cents real	$2184	$1207	4.8%
Variable component of retail tariff	$2860	$1605	5.6%
10 cents real + market buyback rate	$4443	$2338	8.4%

Note: Over the period 2017–18 to 2034–35, a 10 cent real tariff is marginally higher overall than a tariff based on the existing regional regulatory approach (avoided cost).

It is not clear that there are additional benefits that would outweigh the costs of higher electricity prices. Moreover, evidence shows that the costs of above-market feed-in tariff arrangements disproportionately impact the least well-off customers in Queensland.

Barriers to a well-functioning solar export market

The inquiry has not identified significant barriers to solar PV investment and solar export pricing that could be addressed by the Queensland Government in a cost-effective way. That said, some factors can affect the efficiency of the market, and the design of feed-in tariffs:

- Trading of solar exports is generally tied to the purchase of retail electricity.
- Current metering and tariff structures can limit solar export pricing based on the time of export (that is, a time-of-export feed-in tariff).
- Information problems may inhibit consumer decision-making.
- Policy design issues can distort efficient investment and impede the uptake of solar PV in regional Queensland.

The barrier most commonly identified in this inquiry is consumer information problems, which can lead to confusion about the difference between the wholesale price for electricity and the retail price (see Box 1) or to misunderstandings about electricity tariffs in general as well as the uniform tariff policy. Legacy issues associated with 'price anchoring' to the 44c/kWh SBS also fuel consumer misconceptions.

Evidence presented to this inquiry suggests the Queensland Government should ensure:

- consumer education for Queensland customers is accessible and well-targeted;
- future policy design does not provide rooftop solar PV with an unfavourable advantage over other sources of generation including, but not limited to, commercial and large-scale solar/renewables, community solar and other low-emissions technologies, such as gas; and
- connection to the network is as transparent and expedient as possible.

Box 1: Why are solar PV owners not paid the retail electricity price?

During consultations, many solar PV owners presented a view that retailers should pay a feed-in tariff equal to the retail price. A number suggested anything less than the retail price allowed retailers to 'buy solar exports and resell the electricity to neighbours at three times the price'.

However, solar exports are a source of electricity generation, and as such, feed-in tariffs relate to the *wholesale*, not *retail*, price of electricity.

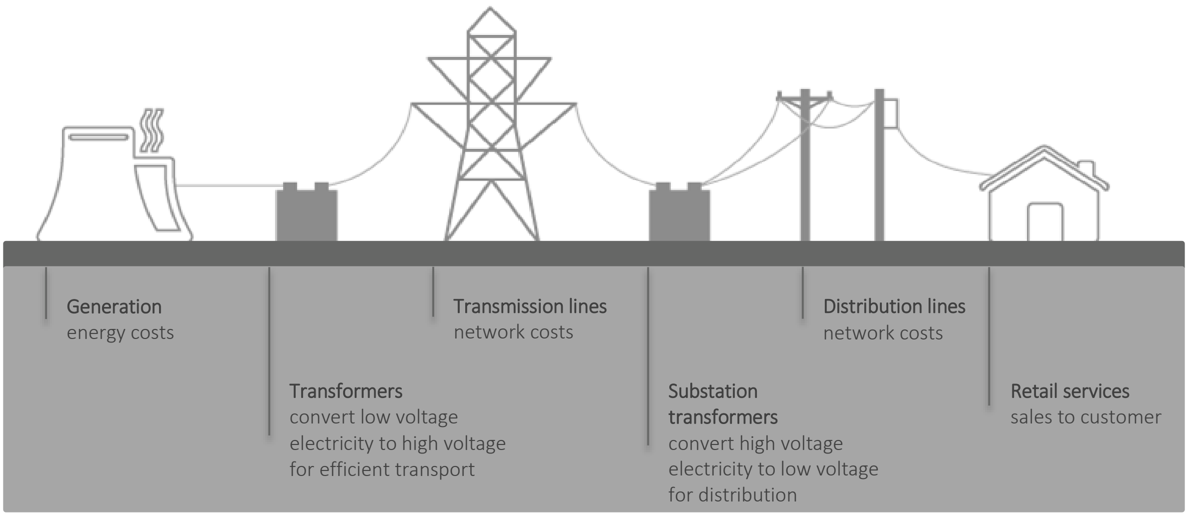
Retailers incur a range of costs that they are required to pay regardless of where or how electricity is generated. Retailers cannot avoid paying certain costs, including:

- network charges (which make up about half of an electricity bill)
- green scheme costs (such as the Australian Government's SRES charges)
- retailing costs (including customer billing).

By purchasing solar PV exports, retailers save only the amount of electricity they need to purchase from the wholesale electricity market, fees related to the National Electricity Market (NEM) and ancillary services, and the value of network line losses.

If retailers were required to pay the retail tariff, then they would incur a loss from serving solar PV customers. Put in another way, with a feed-in tariff set to the retail price, given the choice of purchasing electricity from a solar PV customer or the wholesale market, the retailer would be far better off purchasing from the wholesale market.

The outcome of this would be that retailers would likely avoid servicing solar PV customers.



Regulatory options for setting a fair price for solar PV exports

South east Queensland

The level of retail competition in SEQ appears effective in providing a range of feed-in tariffs and other options for solar PV consumers — and is providing a fair price for solar exports. Most stakeholders — including consumers, peak groups, retailers and network businesses — held the view that there is no basis to regulate feed-in tariffs in SEQ. However, the solar PV industry and some solar PV owners expressed the view that solar feed-in tariffs should be higher.

We investigated whether there is a case for some form of 'precautionary' regulation in SEQ to provide additional assurance that solar export pricing was fair. Three options were identified:

- a mandatory minimum feed-in tariff — the Queensland Competition Authority (QCA) would set a floor price for solar exports;

- a nonbinding benchmark tariff — the QCA would publish a benchmark tariff for solar exports in SEQ; and
- price monitoring — the QCA would monitor and report on solar feed-in tariffs as part of broader retail electricity market monitoring.

Assessed against efficiency, equity and policy governance principles, there does not appear to be a strong case for precautionary regulation of feed-in tariffs in SEQ. In particular, a minimum feed-in tariff is unlikely to have any benefits, but there is scope for costs. The adverse consequences of a minimum feed-in tariff could be significant in both the solar export and electricity market, particularly if it impedes or deters participation in the retail electricity market. The reintroduction of a mandated feed-in tariff may stifle competition (including among retailers that have chosen not to include a solar price in their competitive offers) and act as a barrier to innovation.

The case for both a nonbinding benchmark price and market monitoring is more finely balanced, as these options — assuming they can be implemented in an efficient fashion — are likely to be relatively low cost. But they are also likely to have corresponding low benefits, given the range of pricing information already available in the market.

A nonbinding benchmark tariff does have some downside risks which may be more pronounced in a market with changing products and offers. These risks do not appear to be offset by benefits to consumers.

Including solar feed-in tariffs in the electricity price monitoring arrangements for SEQ would appear to best meet the principles. The government may wish to explore this option to provide an ongoing assessment of the market and greater assurance to consumers.

Regional Queensland

The form of regulation for regional Queensland should limit the likelihood that retailers will exercise excessive market power, while minimising the scope for regulatory error and compliance costs. The most appropriate form of solar price regulation for regional Queensland is price approval. Under this model, prescribed retailers serving small customers in Ergon's distribution area will be required to:

- buy solar exports from small customers; and
- submit prices to the QCA for approval annually.

We recommend price approval — rather than price setting — as this will provide regional customers with consumer protection while removing regulatory constraints on retailers offering more innovative and varied solar-related products.

Under a price approval arrangement, retailers may offer a traditional feed-in tariff. But they may purchase solar exports through other products and services, such as SPPAs, discounts and programs. Price approval also provides opportunities for retailers to consider location-based pricing and time-of-export pricing where feasible — which means customers can be paid more if their energy is worth more, and efficient signals are sent to solar PV investors.

A flexible regulatory approach, which minimises potential market power abuse while not limiting products and offerings, is particularly important in a rapidly changing market where fixed approaches may act as an impediment to innovation and change, including developments around battery storage.

What role for government?

Stakeholders to this inquiry were overwhelmingly positive about the future of solar PV in Queensland. Retailers, for example, highlighted the likely strong growth in solar PV:

> *We expect rooftop solar PV installations to continue growing strongly and have invested in expanding our solar and emerging technologies businesses.[1] [I]nternal projections show that Queensland is well-placed to continue to deploy significant additional residential and utility scale plant over the next decade. The growth in this market will further contribute to meeting the Queensland Government's solar targets.[2]*

The Minister for Energy, Biofuels and Water Supply stated:

> *Our state already has one of the highest uptake of residential rooftop solar panels in the world, and more Queenslanders continue to jump on board. [Thirty] per cent of all detached homes in South East Queensland now have a solar system installed. Not only that, system sizes are increasing as businesses start to take up the opportunities that solar offers. There is strong potential for future growth in emerging sectors, especially as battery storage systems enter the market and product costs continue to fall.[3]*

The Chamber of Commerce and Industry Queensland (CCIQ) noted the growing appetite for business/commercial solar PV:

> *Queensland businesses generally support a transition away from conventional energy towards more renewable energy sources … Given the cost of solar and batteries have decreased substantially, over time more and more businesses will increase the uptake of renewable energy.[4]*

And the Queensland Resources Council (QRC) further highlighted opportunities:

> *Queensland has an opportunity to be a world leader in solar technologies. We have a world class research community, we have a widely dispersed population which is well suited to a decentralised source of electricity generation, we have high levels of solar irradiation and we already have one of the largest rates of residential take-up of solar, with PV panels on almost 1 in 4 homes.[5]*

However, most stakeholder groups considered that, outside of the price approval framework for regional Queensland, there was no role for the government to set or subsidise feed-in tariffs to achieve this future growth. Instead, stakeholders generally considered that consumers and business themselves will drive further growth and innovation in the solar PV market.

This inquiry has found that mandatory solar feed-in tariffs are not an effective or efficient means to achieve the desired environmental, economic and social outcomes. Alternative policies are more likely to achieve objectives at lower cost. State governments have a range of other policy levers to pursue environmental objectives, such as working in national fora to progress national policies that are most likely to achieve least-cost abatement, targeting R&D policy, reducing regulatory burdens to low-emission technologies and reviewing transport, planning, agricultural and other industry policies.

Equally, where there are potential gains from solar PV investment to the electricity supply industry, the government can ensure that the regulatory and market framework does not unnecessarily impede such investment from occurring.

Should the government wish to provide additional support to solar PV, it should design any program in the most cost-effective manner. This includes:

- targeting genuine additional abatement or investment, rather than redistributing income to existing solar investments or investments that would occur anyway;
- minimising distortionary impacts on the electricity market, including on other generation technologies;
- ensuring any program is time-bound and capped, and is monitored and subject to ongoing review; and

[1] Origin Energy, sub. 24, p. 4.
[2] Ergon Energy Queensland, sub. 35, p. 2.
[3] Bailey, M. 2016.
[4] CCIQ, sub. 21, p. 8.
[5] QRC, sub. 27, p. 5.

- providing funding through the budget, rather than recouping costs from electricity customers, to encourage:
  - more rigorous specification of program objectives and expected outcomes;
  - better policy evaluation and recognition of the opportunity cost of any program; and
  - greater transparency and accountability, with actual outlays identified in the Budget Papers.

FINDINGS AND RECOMMENDATIONS

A framework for assessing a fair price for solar exports	
Finding 3.1	A price for solar exports is fair when solar PV owners are receiving an efficient price for the electricity they generate — and remaining electricity consumers are not paying more (or less) than they should for solar PV energy.
Finding 3.2	Solar export pricing arrangements should be assessed against the following principles to determine whether they are fair: (a) Efficiency — Are the pricing arrangements consistent with achieving economic efficiency? Efficiency is broadly defined to ensure resources are allocated to their highest valued use (including accounting for environmental impacts), output is produced at minimum cost and new processes, systems and services are introduced in a timely way. (b) Equity — Do the pricing arrangements avoid cross-subsidies? If a subsidy is proposed, is there a well-developed rationale? If so, how should it be funded? (c) Policy governance and practice — Where prices are regulated, is the regulatory framework transparent and robust? Is it as simple as possible and appropriately balances efficiency versus simplicity where there is a trade-off? Are policies and regulation technology-neutral?
Electricity export market: Competition assessment	
Finding 4.1	In south east Queensland, multiple retailers are competing for solar PV customers, which promotes fair pricing for solar exports. As a result, there is no case to mandate feed-in tariffs to address market power.
Finding 4.2	In regional areas, Ergon Energy (Retail) possesses significant market power, which provides a basis for some form of continued regulation.
Environmental benefits: Assessment	
Finding 5.1	Investors in solar PV systems receive a subsidy from the Small-scale Renewable Energy Scheme (SRES) to reflect emissions reduction.
Finding 5.2	An additional subsidy paid through a feed-in tariff for reducing emissions would be poorly targeted and result in a high cost of abatement, as well as large cross-subsidies between electricity consumers.
Finding 5.3	Better and fairer policy options are available to achieve carbon abatement at a lower cost than can be achieved by subsidising electricity exports from solar PV. Efficient national and international policies should be used to address global problems.
Recommendation 5.1	The Queensland Government should not increase feed-in tariffs to pay solar investors for reducing carbon emissions. Investors already receive a subsidy from the SRES for emissions reduction.

Other rationales: Assessment	
Finding 6.1	Mandating solar feed-in tariffs to induce solar industry development and employment will be paid for by other business and residential consumers (including the least well-off consumers) and is likely to have an overall negative impact.
Finding 6.2	Solar PV has raised the cost of generating electricity in Queensland, with an estimated additional cost in the order of \$75–\$150 million in 2015. However, as the price of solar PV continues to decline, so will the additional cost of generation due to solar PV. Solar PV owners should not be paid for any impact on wholesale prices. Governments do not reward generators for reducing the wholesale price, just as suppliers in other markets are not paid for increasing supply. Paying solar PV owners for any reduction in wholesale prices would likely result in overall higher electricity prices for Queensland consumers.
Finding 6.3	Solar PV may be able to defer network expenditure depending on specific location, penetration level and load characteristics. However, analysis of network data has not identified material network savings from solar PV in Queensland, and to the extent that savings may arise from 2015 to 2020, they will not outweigh the additional costs incurred from integrating solar PV onto the network.
Finding 6.4	We have not identified specific social benefits from solar PV exports that would warrant an increase in the feed-in tariff.
Recommendation 6.1	**The Queensland Government should not increase feed-in tariffs to induce industry development, wholesale market and network infrastructure effects, or other social impacts. The evidence suggests that such a policy would come at a net cost overall.**
Equity considerations	
Finding 7.1	Solar PV is subsidised through the SRES, Solar Bonus Scheme, and the structure of electricity tariffs: (a) The combined subsidy is \$597 million in 2015–16. This does not include other subsidies through national and state government policies. (b) Any new subsidy provided through a feed-in tariff would be in addition to these amounts.
Finding 7.2	While some low income households own solar PV, the overall distributional impact of solar PV subsidies is to transfer income from non-solar households to solar households, and to raise the cost of living for those on the lowest incomes: (a) Subsidies to solar exports result in a large and growing transfer of income from non-solar households to solar households. (b) In considering the distributional consequences of a subsidy policy, if the focus is on the least well-off, then the policy is regressive. On equity grounds, such a policy is demonstrably unfair.
Barriers to a well-functioning solar market	
Finding 8.1	There is no evidence of widespread or major barriers to solar PV investment and solar export pricing. That said, some factors can affect the competitiveness of the market: (a) Trading of solar exports is generally tied to the purchase of retail electricity. (b) Metering and tariff structures can limit efficient solar export pricing based on the time of export. (c) Information problems may inhibit consumer decision-making. (d) Policy design issues can distort efficient investment and impede the uptake of solar PV in regional Queensland.
Finding 8.2	There is no evidence to indicate that Ergon Energy and Energex are using their market power to systematically prevent distributed generation from connecting to the network. Nevertheless, distributed generators should be connected to the network in the most transparent, straightforward and timely manner possible.

Regulatory options for solar feed-in pricing	
Recommendation 9.1	The Queensland Government should retain voluntary arrangements for feed-in tariffs in south east Queensland.
Recommendation 9.2	The Queensland Government should consider including solar feed-in tariffs in the annual price monitoring arrangements for the SEQ retail electricity market.
Recommendation 9.3	The Queensland Government should implement price approval regulation for solar exports from small customers in regional Queensland. Under the price approval process, regional retailers would be required to: (a) purchase solar exports from small customers; and (b) submit their offers to the Queensland Competition Authority (QCA) for approval on an annual basis. The QCA must approve the offers unless they are materially inconsistent with efficient pricing principles. If the regulator does not approve the offers, it can request retailers submit revised offers for approval.
Recommendation 9.4	The Queensland Government should review the price approval regime if: (a) the QCA identifies a sustained market power problem which continues despite the price approval regime in place; (b) the QCA identifies that the potential for exercise of market power no longer exists; or (c) market conditions change materially (for example, through competition or technological change).
Recommendation 9.5	This inquiry has not identified a case for the state government to regulate feed-in tariffs (or otherwise subsidise solar PV) outside establishing the price approval regime for regional Queensland. If the Queensland Government elects to intervene in the market to support solar PV, then any program should be designed to achieve its objective at least-cost, including by: (a) targeting genuine additional abatement or investment, rather than redistributing income to existing solar investments or investments that would occur anyway; (b) minimising distortionary impacts on the electricity market, including on other generation technologies; (c) ensuring any program is time-bound and capped, and is monitored and subject to ongoing review; and (d) funding any program through the budget rather than recouping costs from electricity customers, to encourage better evaluation and recognition of the opportunity costs, greater transparency and accountability, and lower adverse impacts on the least well-off.

1 INTRODUCTION

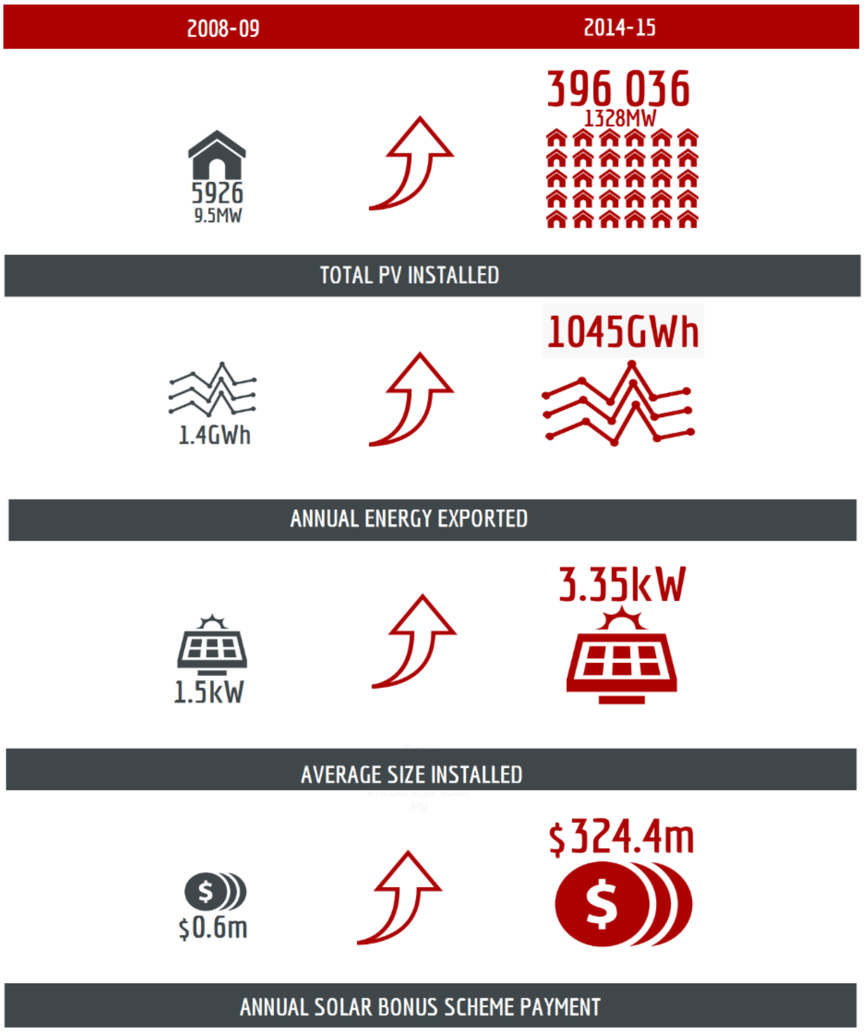
The Queensland Government asked the Queensland Productivity Commission (QPC) to investigate and report on a fair price for solar power produced at the home or business premises of a 'small customer' and exported into the electricity grid. This report sets out a framework for solar feed-in pricing in Queensland.

1.1 Background

Since 2008 there has been an exponential uptake of solar photovoltaic (PV) panels in Queensland. From less than 1600 solar PV customers in 2007, by 31 December 2015:

- there were more than 450,000 solar PV customers;
- total installed solar PV capacity is 1478 MW — equivalent to the second-largest generator in Queensland; and
- Queensland has one of the highest levels of residential solar PV in the world.

Figure 2: Small customer solar PV in Queensland



Future market changes and technological advances, including cost-effective battery storage, may have further significant impacts on solar and electricity markets.

Rapid solar PV expansion has raised opportunities, but also challenges, for the electricity sector, consumers and governments. Many of these challenges primarily relate to the fact that rooftop solar PV can impose costs and accrue benefits to parties inside and outside the solar export market.

As a result, there has been considerable policy debate on:

- whether solar PV owners are receiving a fair price for the electricity they export;
- whether non-solar customers are paying more than they should for electricity due to solar PV; and
- who should bear any costs associated with feed-in tariff arrangements.

In this context, the Queensland Government has asked us to investigate and report on a fair price (or prices) for solar exports for small customers. The terms of reference state that any price for exported solar energy must not have an unreasonable impact on non-solar users.

The terms of reference asks us to consider a number of factors including:

- the public and consumer benefits from exported solar PV generation, including social, economic and environmental benefits;
- whether households and business are already fairly compensated for public and consumer benefits (such as through renewable energy programs, rebates and market contracts);
- the costs and benefits across the electricity supply chain due to the exported solar PV energy, taking into account temporal and locational factors;
- the perception of electricity customers about whether any cost they bear from the fair value is 'unreasonable';
- mechanisms in the electricity system which may prevent the true value of exported solar energy being realised/monetised; and
- the government's target of one million rooftops by 2020 (or 3000 MW of solar PV).

The coverage of this inquiry is confined to issues related to solar feed-in tariffs in Queensland. Other policy matters related to renewable energy and environmental programs, including the SBS, are covered by the QPC inquiry into electricity pricing.

The full terms of reference are provided at Appendix A.

1.2 Queensland Government policy

The Queensland Government has a commitment to increasing the contribution of renewable energy to Queensland's energy mix. The Queensland Government has said that critical to this commitment is building on Queensland's world-leading uptake of solar energy.[6]

The Queensland Government has set a target of one million rooftops or 3000 MW of solar PV in Queensland by 2020. It said that by including a capacity target, it will harness Queensland's potential to grow solar PV on businesses, community buildings and large commercial or industrial sites.

[6] Queensland Government, sub. 40, p. 2.

In setting this target, the Queensland Government said that:

> *the Government is mindful of the potential impact on electricity prices. This is why the Government has specifically asked the Commission, as part of its Fair Price for Solar Inquiry, to ensure that a 'fair price' does not have an unreasonable cost on network costs for non-solar users.*[7]

The Queensland Government is also undertaking a Renewable Energy Study, including an independent public inquiry into a 50 per cent renewable energy target by 2030. It has said:

> *The Renewable Energy Study will enable the Government to develop a transition to renewable energy that balances costs with economic and environmental outcomes. While the primary focus of this study will have the potential to expand Queensland's renewable energy sector and reduce greenhouse gas emissions, the Government will consider broader outcomes.*[8]

1.3 Our approach

The QPC's approach to this inquiry consists of four main components:

- establishing a framework for solar export pricing policy;
- assessing all the factors that may impact on the value of solar PV exports, including electricity generation and environmental values, and whether they are being fairly reflected in solar feed-in pricing;
- identifying barriers to solar export pricing and a well-functioning solar export market, and cost-effective options to address those barriers; and
- considering the most appropriate form and design of regulation for a feed-in tariff to achieve the objective/s at minimum cost.

The QPC is guided by the terms of reference and the principles underpinning the *Queensland Productivity Commission Act 2015*, which focus on productivity, economic growth and improving the living standards of Queenslanders. In considering factors and making assessments, we have adopted a community-wide view that extends beyond the interests of particular individuals or groups to consider the overall costs and benefits of feed-in tariff options.

1.4 Conduct of inquiry

The QPC has sought to provide all interested parties with a range of opportunities to contribute to this inquiry:

- An issues paper was released for consultation in October 2015 and received 44 submissions;
- A series of public hearings, public forums and roundtable discussions with experts were held in November 2015 and April 2016 across Queensland, including in Brisbane, Toowoomba, Bundaberg, Rockhampton, Townsville, Mt Isa and Cairns;
- A draft report was released for consultation in March 2016 and received a further 24 submissions; and
- Meetings and site visits with the solar industry, consumers, electricity supply participants, advocacy groups and relevant Queensland Government agencies were held throughout the course of the inquiry.

[7] Queensland Government, sub. 40, p. 2.
[8] Queensland Government, sub. 40, p. 2.

A full list of submissions and consultations is provided in Appendix B.

We would like to thank all organisations and individuals who have contributed to this inquiry.

1.5 Report structure

The structure of this report is as follows:

- Chapter 2 discusses the solar export market in Queensland;
- Chapter 3 sets out a framework for solar feed-in pricing policy;
- Chapters 4, 5 and 6 assess the case for mandating feed-in tariffs to:
  - address market power in the solar export market (Chapter 4);
  - account for environmental benefits (Chapter 5);
  - stimulate solar industry development and employment, and network or wholesale market benefits (Chapter 6);
- Chapter 7 outlines the distributional impacts of feed-in tariffs;
- Chapter 8 examines the barriers to a well-functioning solar export market; and
- Chapter 9 outlines how feed-in tariffs can be regulated and sets out a regulatory framework for regional Queensland.

Appendices A–I provide supporting material and analysis.

2 THE SOLAR EXPORT MARKET IN QUEENSLAND

This chapter outlines the history of feed-in tariffs in Queensland, how feed-in tariffs are set under existing frameworks, and national and international trends in feed-in tariff design and regulation. It also examines key factors affecting the solar export market and likely future growth, and the impact of technological developments.

Key points

- Currently, there is no mandated feed-in tariff in SEQ — all feed-in tariffs are market-driven. In regional Queensland, a regulated feed-in tariff for small customers is determined on an annual basis by the Queensland Competition Authority (QCA).
- From 2008 to 2012, solar PV installations grew exponentially — driven by federal and state government incentives, rapidly falling costs for solar PV and rising electricity prices. From 2012 onwards, solar PV installation has continued to grow, albeit at a slower rate, with more than 39,000 installations in 2015. Queensland has more than 450,000 solar PV installations with over 1200 accredited installers.
- Rapid expansion of solar PV has also occurred across Australia and overseas. Globally, at the end of 2014 there was approximately 177 GW of solar PV installed, with around 40 GW installed during 2014.
- The main factors impacting solar PV investment are system costs and electricity prices. Non-premium feed-in tariffs have a small impact.
- The outlook for the solar PV market is positive:
  - There is a range of new products and services that are supporting continued growth of the industry.
  - Modelling projects rooftop solar PV in Queensland will reach 3000 MW by 2022 (with no change in policy settings).
  - Battery prices are expected to fall 50 per cent by 2020, with installed capacity expected to reach 900 MWh by 2035.

2.1 Feed-in tariffs in Queensland

A feed-in tariff is a payment to consumers for the electricity they export to the network. Feed-in tariffs can be mandated by the government or offered voluntarily by an electricity retailer.

In July 2008, the Queensland Government introduced the Solar Bonus Scheme (SBS) as part of the *Clean Energy Act 2008*. The scheme was established with the aim to:

- make solar power more affordable for Queenslanders;
- stimulate the solar power industry; and
- encourage energy efficiency.

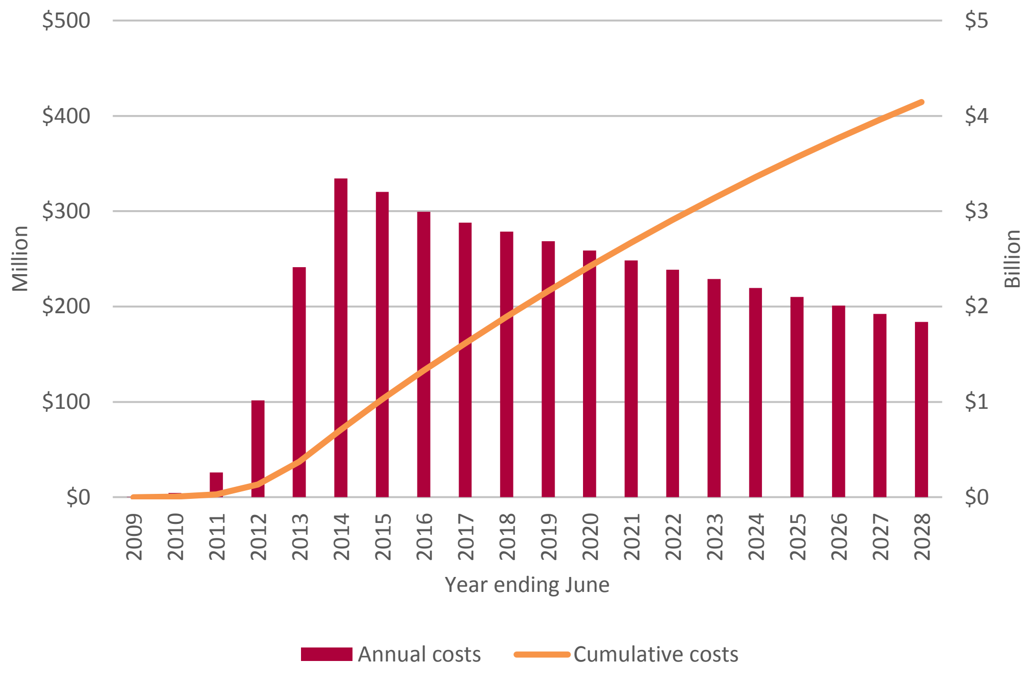
The scheme was made available to small customers who consume less than 100 MWh per year. The initial feed-in tariff was set at 44c/kWh for net[9] eligible electricity supplied to the network, with the solar bonus payment for exported electricity reflected as a credit on the retail bill.

The scheme was closed to new applications from 9 July 2012 and replaced with an interim scheme until 30 June 2014. The interim scheme reduced the feed-in tariff from 44c/kWh to 8c/kWh. Participants on the 44c/kWh feed-in tariff will continue to receive this amount for the duration of the scheme (until 2028) provided they maintain their eligibility.[10]

The cost of the 44c/kWh scheme is recovered by the distribution network service providers, Energex and Ergon Energy (Network). They are required to pay the amount of the feed-in tariff, which is then credited to the solar PV customer by the retailer. As network charges are regulated, these costs are recovered through higher network charges for all customers.

The QCA estimated that the SBS added around $89[11] to the average Queenslander's annual electricity bill for a residential customer on tariff 11[12] in 2015–16. The cost to electricity customers over the life of the scheme (until 2028) is estimated at more than $4.1 billion (Figure 3).

Figure 3: Solar bonus scheme costs: 2008–28



Source: QPC 2016a.

In 2012, the Queensland Government commissioned the QCA to undertake an inquiry into feed-in tariffs. Following the review, the then Queensland Government announced that a regulated feed-in tariff would apply for regional customers only — customers in SEQ could access market offers from competing retailers.

[9] A net feed-in tariff pays the PV system owner only for surplus energy they produce, whereas a gross feed-in tariff pays for each kilowatt hour produced by a grid connected system.

[10] QCA 2013a. The QPC final report, *Electricity Pricing Inquiry*, recommends the Queensland Government consider whether there is merit in an earlier end to the 44c/kWh scheme rather than 2028 as planned.

[11] QCA 2015a.

[12] Tariff 11 is the standard residential retail electricity tariff for general domestic/residential electricity supply. The majority of Queensland customers are on this tariff. Customers pay the same rate for unit of electricity consumed, whatever the time of day.

Box 2: Queensland Competition Authority 2013 Inquiry into solar feed-in tariffs

In August 2012, the QCA was asked to estimate a fair and reasonable feed-in tariff for PV exports in Queensland and investigate options to minimise or more equitably share the costs of the SBS. In March 2013, the QCA handed down its final report, *Estimating a Fair and Reasonable Feed-In Tariff for Queensland*, finding that:

- Future feed-in tariff schemes should be funded by electricity retailers, rather than regulated network businesses, to avoid cross-subsidies and the inequitable recovery of costs from those customers least able to afford them.
- The fair and reasonable value of PV exports should be the direct financial benefit that electricity retailers receive when they on-sell exported energy from their PV customers.
- There is no compelling evidence to support a regulated, mandatory minimum feed-in tariff for customers in the south east Queensland retail electricity market.
- Regulated minimum retailer funded feed-in tariffs should be established for regional customers depending on customer location.
- The cost of the SBS could be controlled by introducing a mandatory contribution from retailers set at the estimated direct benefit to the retailer resulting from PV exports.
- Government could move PV customers to a time-of-use tariff to expose them to a more cost reflective fixed charge than they face under flat residential tariffs. This would reduce the problem of PV customers avoiding some of the true cost of their network access due to their net consumption profile, which leads to higher average variable network charges.

Source: QCA 2013a.

During the 2015 election, the Queensland Government committed to a range of policies to encourage solar PV, including:

- an investigation into how Queensland can achieve a target of 50 per cent renewable energy by 2030;
- a target of one million rooftops having solar panels by 2020;
- a QPC inquiry to identify a fair price for solar power produced by small customers and exported to the electricity grid; and
- a trial 40 MW renewable energy auction to support private investment and jobs in the renewable energy industry.[13]

2.1.1 How feed-in tariffs are set

South east Queensland

There is no mandated feed-in tariff in SEQ. Ten retailers currently offer voluntary retailer-funded feed-in tariffs of up to 11c/kWh (Table 2).

[13] Queensland Labor 2015.

Table 2: Voluntary feed-in tariffs south east Queensland (c/kWh)

Retailers	*Brisbane*	*Sunshine Coast*	*Gold Coast*
AGL	6	6	6
Click Energy	11	11	11
Diamond Energy	8	8	8
Dodo Power & Gas	4	4	4
Energy Australia	6	6	6
Origin Energy	6	6	6
Powerdirect	8	8	8
Lumo Energy	6	6	6
Urth Energy	10	10	10
QEnergy	–	–	–
Sanctuary Energy	–	–	–
Simply Energy	6.2	6.2	6.2

Note: As at 7 June 2016. Postcodes sampled are Brisbane 4000, Sunshine Coast 4558 and Gold Coast 4217.

Source: EnergyMadeEasy website, https://www.energymadeeasy.gov.au, accessed 7 June 2016.

Regional Queensland

Small customers in regional Queensland (those located in the Ergon Energy distribution network) have a regulated (mandatory) feed-in tariff set by the QCA. The QCA sets the feed-in tariff based on an avoided cost approach, which estimates the direct financial costs that Ergon Energy (Retail) avoids when it on-sells a unit of exported electricity from its solar PV customers. That is, the approach identifies the costs that can and will be avoided by retailers in sourcing the energy from solar customers instead of from the wholesale market.

These avoidable costs are:

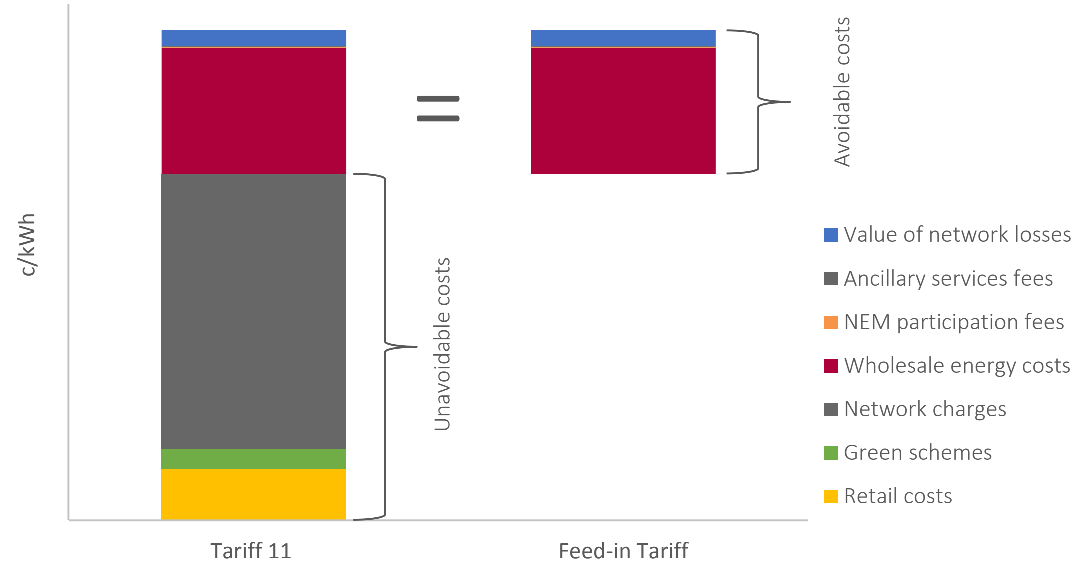
- wholesale energy costs;
- National Energy Market (NEM) and ancillary fees; and
- transmission and distribution losses.

The QCA calculates these costs for the purposes of setting regulated retail prices.[14]

The main advantage of the avoided cost approach is that the money paid for the electricity produced by solar PV is roughly equivalent to the money the retailer receives when it on-sells the electricity to the next customer. This means that the solar PV owner receives a feed-in tariff, but the customer buying the energy is not required to pay more than the market price for the energy. Figure 4 is an approximation of how this works.

[14] QCA 2015b.

Figure 4: Comparing feed-in tariffs to tariff 11: An avoided cost approach



The regulated feed-in tariff for regional Queensland in 2016–17 is 7.448c/kWh. Table 3 shows how the regulated tariff has changed over four years.

Table 3: Solar feed-in tariff for regional Queensland 2013–14 to 2016–17

Cost component	*c/kWh*			
	2013–14	*2014–15*	*2015–16*	*2016–17*
Wholesale cost of energy	6.858	5.575	5.57	6.569
National Electricity Market and ancillary services fees	0.07	0.095	0.083	0.081
Value of network losses avoided	0.624	0.864	0.695	0.798
Feed-in tariff	*7.553*	*6.534*	*6.348*	*7.448*

Source: QCA 2013a; QCA 2015b; QCA 2016.

2.2 The Queensland market for solar exports

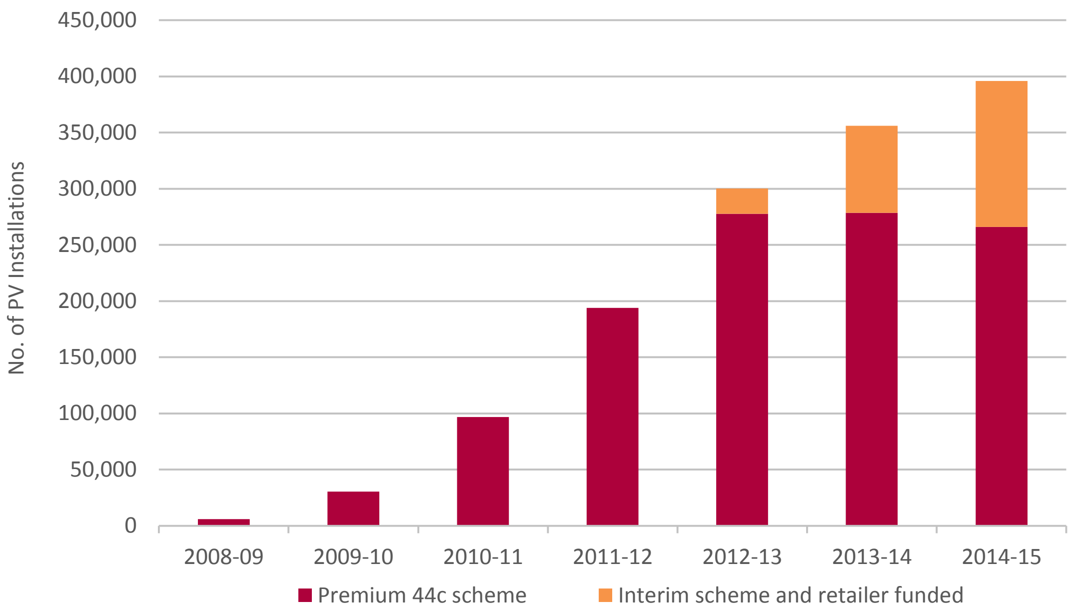
Solar exports are dependent on, and can affect, a number of market segments:

- the solar PV purchase and installation market (consumers and installers);
- the electricity supply chain (generators, networks, retail businesses and consumers); and
- the solar export market (solar PV owners or 'prosumers' and retailers).

2.2.1 Solar PV uptake

From a base of less than 1600 residential systems at the end of 2007, by 2014–15 Queensland had about 400,000 systems installed, representing around 30 per cent of Australia's solar PV installations (Figure 5).

Figure 5: Solar rooftop PV installations in Queensland 2008–09 to 2014–15

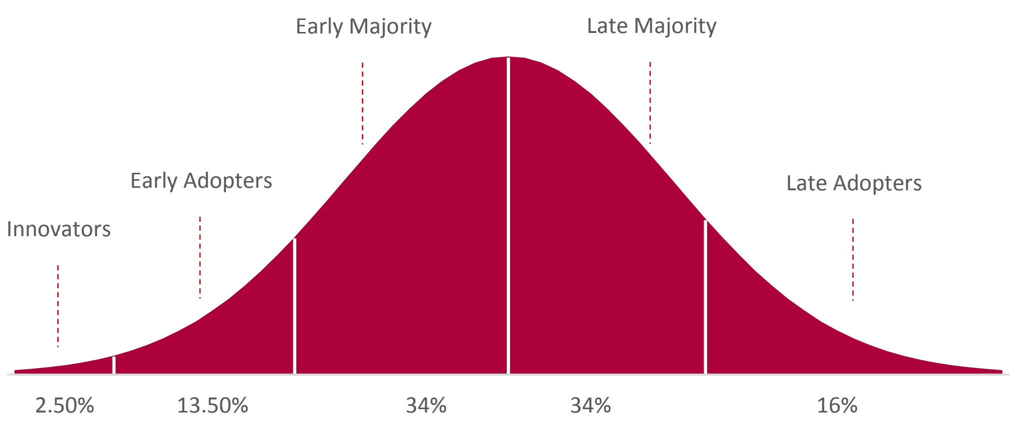


Source: Energex and Ergon Data.

Since 2013, installations have continued to grow, albeit at a declining rate — 39,103 additional solar PV systems were installed in 2015, or roughly 750 systems a week. Factors likely to have influenced the rate of growth include the easing of the oversupply of panels from China, the close of premium feed-in tariff schemes and the weaker Australian dollar.

The level of uptake could also be expected to diminish as penetration levels increase. Should residential solar PV follow the standard innovation adoption model (Figure 6), it is possible Queensland may have already passed its peak level of uptake.

Figure 6: Innovation adoption model



Source: Rogers 1962.

Under a combination of these influences, the solar industry has been moving into a period of more stable growth.

2.2.2 Solar installers

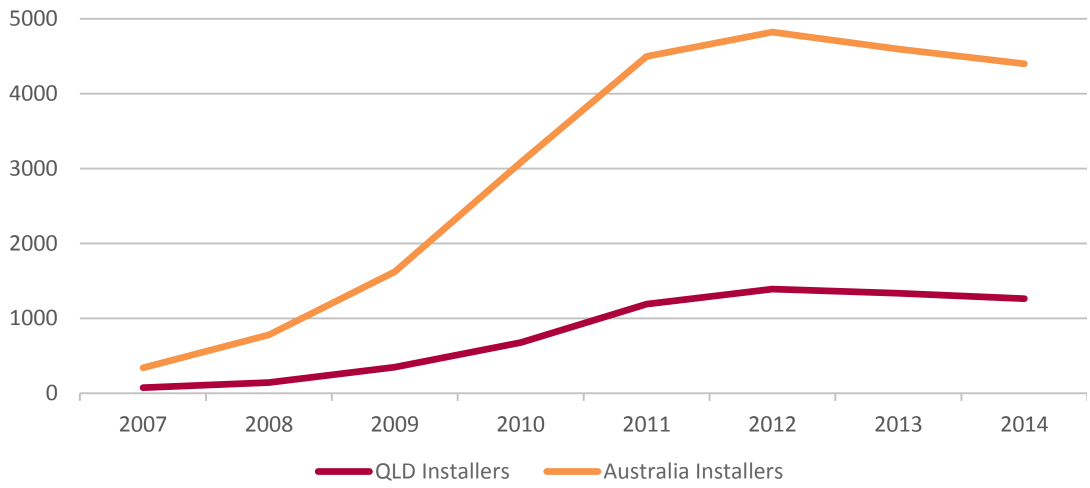
The number of solar PV installers in Queensland rose from 73 in 2007 to 1391 at its peak in 2012, but fell to 1263 in 2014 (a 9.2 per cent drop), as can be seen in Table 4 and Figure 7.

Table 4: Number of accredited designers and installers

Year	Total number of installers		Percentage change in number of installers	
	QLD	Australia	QLD	Australia
2007	73	338	–	–
2008	143	778	96	130
2009	349	1619	144	108
2010	675	3081	93	90
2011	1187	4495	76	46
2012	1391	4821	17	7
2013	1336	4595	–4	–5
2014	1263	4396	–5	–4

Source: CEC 2014a.

Figure 7: Number of accredited designers and installers



Source: CEC 2014a.

2.3 The electricity market

Solar PV and solar exports form part of the broader electricity market, and can therefore affect each stage of the electricity supply chain (Figure 8). Solar PV owners use the distribution network to export excess electricity; they buy and sell electricity through retailers; and they reduce the demand for wholesale market generation.

Electricity supply is unlike many other goods and services. It involves a complex series of interrelated physical and financial transactions. The electricity market was initially designed as a one-way system:

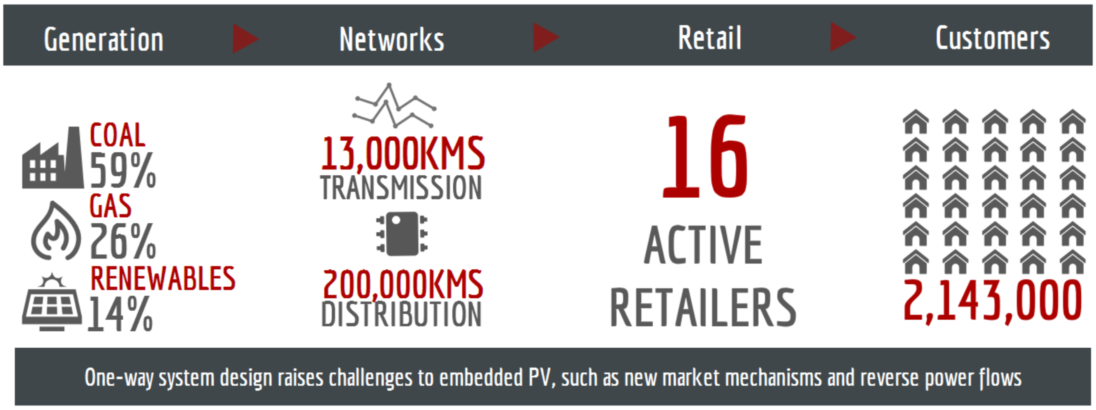
> *Throughout its history, the fundamentals of the electricity industry have remained comparatively unchanged: electricity was generated from central points in the grid (the majority of power stations were coal-fired), it travelled via a transmission network (in a single direction) to business and residential consumers who had little influence on the generation source of the electricity they purchased, or on the prices they paid.*[15]

[15] Stanwell Corporation Limited, sub. 30, p. 7.

Changes in this market can have systemwide impacts and raise opportunities, but also challenges:

> *In 2015, energy businesses throughout the world are facing unprecedented change. The drivers of change are global and their potential for influence reaches far beyond the energy industry. Increasing consumer choice and influence; an evolving energy mix; the exponential growth of digital technology; world leaders' support for carbon reduction and the resulting shift in global sentiment; and an anticipated step change in the demographics, skills and expectations of the workforce, will all radically affect the electricity industry over the next ten years.*[16]

Figure 8: Queensland electricity system

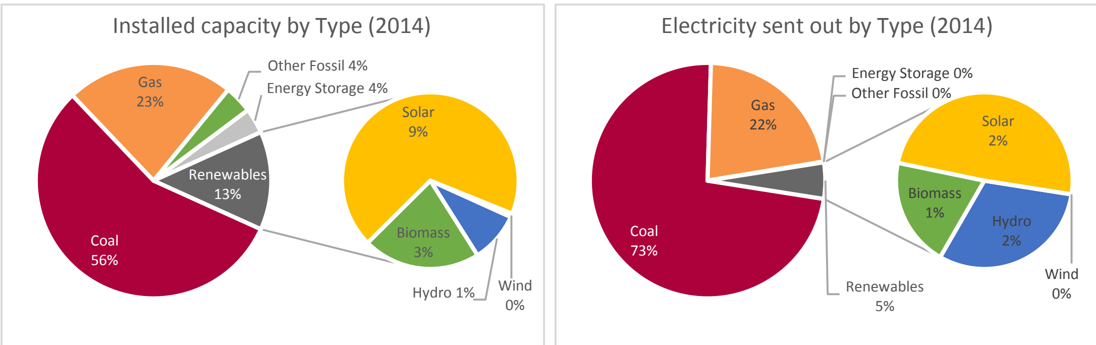


2.3.1 Generation

Queensland's electricity supply is provided by government-owned corporations (CS Energy and Stanwell Corporation), which represent around 65 per cent of the generation market, and private entrants (largely gas-fired generation), which represent around 35 per cent of the market.

While coal generators represent only 56 per cent of the installed generation capacity, due to their lower cost of production and base load capability they represent around 73 per cent of the overall electricity supply (Figure 9).

Figure 9: Installed capacity and electricity sent out by type



Source: Department of Energy and Water Supply.

Renewable energy policies have significantly altered the generation mix in the NEM.[17] In particular, the expansion of the Renewable Energy Target (RET) in 2007 contributed to 2300 MW of wind capacity in the following six years, more than tripling existing capacity.

Oversupply has reduced the need for further investment, with a significant number of existing plants being decommissioned or periodically taken offline. The majority of investment (63 per

[16] Stanwell Corporation Limited, sub. 30, p. 7.
[17] AER 2014a, p. 31.

cent) over the four years to 30 June 2014 was in wind generation, with the remainder in gas-fired plants.[18] The Australian Energy Market Operator (AEMO) has estimated that new generation capacity will not be needed in Queensland for seven years, even under a high-growth scenario.[19]

2.3.2 Network infrastructure

Queensland has an extensive transmission and distribution network.[20] All network infrastructure in Queensland is government-owned and comprises:

- Powerlink, which owns and operates the high-voltage transmission network across Queensland, and the main interconnection to the NEM;
- Energex Limited (Energex), which owns and operates the electricity distribution network in south east Queensland; and
- Ergon Energy Corporation Limited (Ergon Energy (Network)), which owns and operates the electricity distribution network in regional Queensland and the north-west Queensland network around Mt Isa, as well as 34 isolated networks (including 33 small-scale generators) in more remote locations across Queensland.

The networks are geographic monopoly businesses whose revenue and prices are regulated by the Australian Energy Regulator (AER). The National Electricity Law and Rules set out the regulatory framework for electricity networks. The AER administers these rules as they apply to economic regulation of the network businesses.

Queensland's network businesses operate under a revenue cap regulatory mechanism. They apply to the AER to assess their revenue requirements for each five-year regulatory period. The AER forecasts the revenue required to cover the network's efficient costs and provide a commercial return on capital — the maximum allowable revenue for the regulatory period.[21]

Given the changes in market conditions and business expenditures, there were significant reductions in allowable revenue in the AER determinations for the recent distribution networks in the 2015–20 regulatory period.

Network costs are the single largest component of retail prices and are expected to make up around 46 per cent of retail prices in 2015–16. This is down from the peak level of 49 per cent of the retail price in 2011–12.

2.3.3 Retail electricity markets

Full retail competition was introduced into Queensland on 1 July 2007.

As at 31 March 2015, there were 16 active retailers operating in Queensland, mainly in SEQ. The combined market share of the two incumbent retailers, Origin Energy and AGL, has been falling gradually, but remains at approximately 81 per cent of the SEQ market.[22]

Most small regional and rural customers continue to be supplied by the government-owned retailer, Ergon Energy (Retail), under a standard retail contract reflecting regulated tariffs. The proportion of large regional business customers on market contracts is higher, at around 27 per cent[15] — and is higher again in the eastern region.

[18] AER 2014a.
[19] AEMO 2015a, p. 14.
[20] Department of Energy and Water Supply 2014, p. 8.
[21] AER n.d.
[22] QCA 2015c, p. 35.

2.4 National and international trends in feed-in tariffs

Most jurisdictions in Australia have followed a similar path to Queensland, having offered premium feed-in tariffs, then shifting to feed-in tariffs based on energy value or deregulating the market. Where feed-in tariffs are regulated, most jurisdictions have adopted an avoided cost approach to determine the value of electricity generated by solar PV (Table 5).

Table 5: Feed-in tariffs in Australia

State	*Closed subsidy scheme(s)*	*Current FiT policy / regulation*
Qld	44c/kWh net scheme until 2028 Available to customers consuming less than 100 MWh per annum	No regulation in SEQ. Market offers. Mandatory FiT in regional Queensland based on retailers' avoided cost. FiT of 7.448c/kWh in 2016–17 for small customers.
NSW	20c/kWh or 60c/kWh until 31 Dec 2016 Available to customers consuming less than 160 MWh per annum	Voluntary benchmark solar FiT set at 4.7 to 6.1c/kWh Mandatory retailer contribution towards the closed SBS of 5.2c/kWh
Victoria	Three closed net schemes 60c/kWh to 31 Dec 2024 25c/kWh until 31 Dec 2016 1-for-1 until 31 Dec 2016	Mandatory FiT paid by retailers Minimum FiT for 2016 is 5.0c/kWh
WA	Net scheme available for 10 years Pre 1 July 2011 — 40c/kWh Post 1 July 2011 — 20c/kWh	Retailers, Synergy and Horizon Power must offer customers a buyback scheme at rates subject to regulatory approval Synergy customers receive 7.135c/kWh Horizon Power (regional) rates are 7.14–51.41c/kWh depending on location
SA	44c/kWh to 30 June 2028 and 16c/kWh to 30 September 2016 Maximum export of 45 kWh per day applies in some circumstances	R-Fit of 6.8c/kWh to apply from 1 January 2016 to 31 December 2016 Available to customers consuming less than 160 MWh pa system up to 10 kVA (single phase) or 30 kVA (three phase)
Tas	Net 1-for-1 FiT until 1 January 2019	Mandatory FiT of 6.535c/kWh for 2016–17
ACT	Five premium FiT rates (30.16c/kWh–50.05c/kWh) gross scheme for 20 years ActewAGL's 1-for-1 gross FiT until 2020	No regulation. Market offers based on net metering
NT	For new connections, the feed-in tariff is 1-for-1 (based on the customer's consumption tariff). Customers under the Alice Springs Solar City initiative receive 51.28c/kWh, capped at $5/day.	

Similar trends have arisen internationally. Globally, there has been exceptionally high growth in solar PV in the last decade. Global installed capacity has risen from about 8 GW in 2007, to approximately 177 GW in 2014. Around 40 GW, over 20 per cent of the total, was installed during 2014. Although feed-in tariffs exist in many countries, the term is used to refer to many different types of policies (see Box 3). For example, some provide a fixed subsidy to large-scale solar PV.

Box 3: Feed-in tariffs: Different international policies

A review of international feed-in tariff policies reveals that a variety of approaches are used, which reflects a diversity of policies. These approaches can be divided into four basic categories:

- *Based on the actual levelised cost of renewable energy generation.* This approach is most commonly used in the European Union.
- *Based on the 'value' of renewable energy generation generally expressed in terms of avoided costs*. This approach is used in California, as well as in British Columbia.
- *Offered as a fixed-price incentive* without regard to levelised generation costs or avoided costs. This approach is used by certain utilities in the United States.
- *Based on the results of an auction or bidding process.* An auction-based mechanism can be applied and differentiated based on different technologies and project sizes.

Source: Coutre et al. 2010.

Table 6 compares solar PV costs and policies across 15 countries. The different approaches, along with variations in electricity markets and impacts of other renewables policies, make direct comparison difficult. Nevertheless, some general observations can be made.

Table 6: Comparison of international solar PV costs and policies

		Australia	Austria	Canada	Denmark	France	Germany	Italy	Japan	Malaysia	Norway	Spain	Sweden	Switzerland	Thailand	USA
Indicative module prices (USD/W)		0.70	0.8–0.9	0.80	0.7–1.6	0.7–0.9	0.80	0.70	1.90	0.90	1.70	0.80	1.20	1.00	1.2–1.6	0.76
Indicative installed system prices in 2014 (USD/W)	*Residential*	1.76	2.33	2.73–3.64	1.79–3.22	4.00–5.33	2.13	1.93–2.52	3.47	2.60	3.20	2.93	2.83	2.74–4.94	1.84–3.07	4.61
	Commercial	1.61	1.96	2.64	1.79–3.58	2.80-3.20	1.65	–	–	2.45	2.56	2.00	1.90	2.20–3.29	1.53–2.61	3.44
	Industrial	1.63	–	2.00	1.79–2.68	–	–	–	–	2.30	–	1.60	–	2.09	1.69–2.31	–
Lowest feed-in tariffs (USD/kWh)		0.05	0.13	0.25	0.07	0.09	0.38	–	0.30	0.30	–	–	–	0.15	0.17	+
Highest feed-in tariffs (USD/kWh)		0.54	0.17	0.35	0.11	0.36	0.41	–	0.34	0.31	–	–	–	0.27	0.21	+
Indicated household retail electricity prices (USD/kWh)		0.27	0.27	0.06–0.15	0.40	0.19	0.38–0.41	0.21–0.27	0.28	0.10	0.11–0.16	0.25	0.27	0.17	0.07–0.1	0.09–0.37
Direct capital subsidies		+	R	R		R	+	R	+			+	+		+	+
Green electricity schemes		+	+	+			U						+	U		U
PV–specific green electricity schemes		+	+											+		+
Renewable portfolio standards		+							+		+		+			+
Financing schemes for PV		+	+				+	+	+							+
Tax credits						–		+	+/*	+		+		+		+
Sustainable building requirements		+	+	+	+		+	+	+	+				+		U

U Some utilities have such measures.
L Implemented at local level (municipalities).
+ Support schemes used in 2014
R Implemented at regional level
** Starting in 2015*
– Cancelled in 2014
Note: Numbers are rounded values in USD according to average exchange rates.
Source: International Energy Agency 2015.

As in Australia, many countries, especially in Europe, offered premium feed-in tariffs to stimulate solar PV expansion (see Box 4 on feed-in tariffs in Germany). Most countries followed a similar course to the Australian experience, whereby high tariff rates helped fuel rapid expansion, but at a very high cost to taxpayers or electricity customers. Many feed-in tariffs have since been reduced or abolished.

Box 4: Feed-in tariffs in Germany

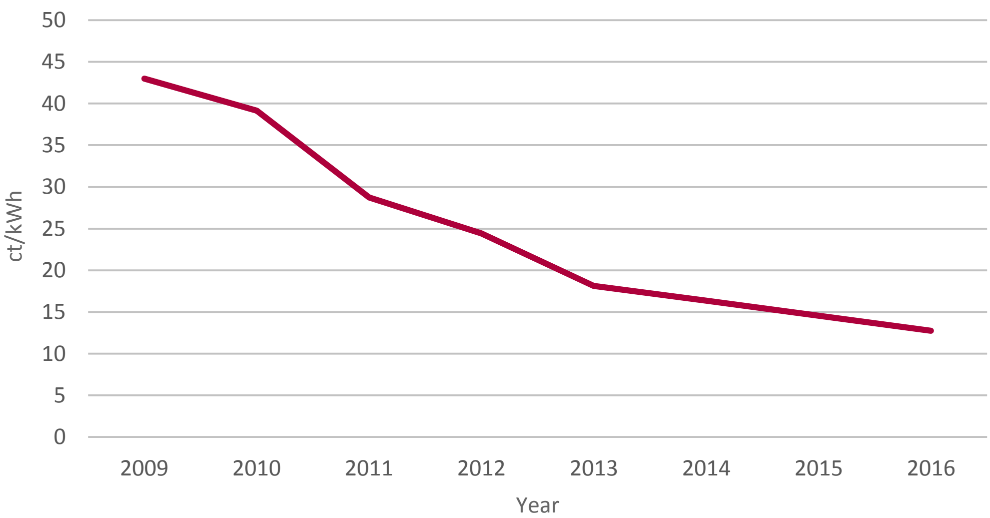
In 1990, Germany adopted its Stromeinspeisegesetz ('StrEG'), which roughly translates as 'electricity feed-in law'. This policy covered several technologies with specific rates for solar, wind, hydropower, biomass and landfill or sewage gas.

Germany's feed-in tariff is a cost-based tariff, where investors in renewables receive sufficient compensation to provide a return on their investment (ROI) irrespective of electricity prices on the power exchange. In Germany, the target ROI is generally around five to seven per cent.

From 1991 to 1999 the rates for solar and wind fluctuated between 8.45 and 8.84€c/kWh. In 2000 it adopted the Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz 'EEG') which raised the solar feed-in rate from 8.53 to 50.62€c/kWh with a cap of 350 MW installed capacity. This was raised in 2002 to 1000 MW installed capacity. The costs incurred are spread evenly among the distribution providers and passed on to all German electricity users (referred to as the EEG surcharge).

The rapid price reduction of solar PV saw feed-in tariffs decline in pace with market evolution (degression). In 2012, Germany abandoned feed-in tariffs for installations above 10 MW and has continued to reduce feed-in tariffs levels since. Figure 10 shows the feed-in tariff decline for systems under 10 kW.

Figure 10: Solar PV feed-in tariffs in Germany up to 10 kW



As of 1 January 2016 the solar feed-in rate is 12.75€c/kWh. The total EEG cost expected for 2016 is €22.9 billion and the EEG surcharge has been set at 6.354€c/kWh, which represents approximately 21 per cent of typical household bill. The surcharge is equivalent to about €280 per person per year.

Sources: Davies & Allen 2014; Fraunhofer ISE 2015; Lang & Lang 2016.

The United Kingdom Government introduced a feed-in tariff scheme in 2010 to encourage small-scale renewables and set initial tariffs as high as 45.4 pence per kilowatt hour (p/kWh). The scheme has progressively been reviewed and scaled back primarily due to costs. In 2014–15, the cost of the scheme was £866 million with an abatement cost of £249 per tonne of CO_2 (falling from a high of £651 per tonne in 2011).[23] In December 2015, the government announced that feed-in tariffs

[23] Ofgem (UK) 2015, p. 17.

for small solar PV systems would be reset to 4.39p/kWh in 2016, falling to 3.55p/kWh in 2019. The Department of Energy and Climate Change concluded:

> *Government continues to consider renewables to be a key part of the transition to a low-carbon economy and an essential part of the energy mix. Support for FITs projects [however] is currently projected to cost at least £1.74bn a year by 2020/21, if measures are not taken to control spend.*
>
> *Government support is designed to help technologies stand on their own two feet, not encourage reliance on subsidies. It is one of this Government's priorities to bring about the transition to low-carbon generation as cost effectively and securely as possible ... The measures set out in this response are about protecting bill payers from unacceptable costs in the future and ensuring that support for renewables remains affordable.* [24]

Similarly, Spain has ceased all feed-in tariffs as a result of unforeseen uptake and costs incurred, and is implementing a range of taxation measures in an effort to recoup its policy deficit. Appendix C provides further information on recent developments in interstate and international feed-in tariffs.

2.5 Factors affecting solar PV investment

The return a household or small business receives from installing solar PV depends on system installation costs, the value of small-scale technology certificates (STCs), solar export revenues and any savings from reduced imports from the electricity grid:

- *System installation costs:* include the up-front capital costs of installing the system — the price of the panels, inverter and other equipment costs, as well as labour installation costs;
- *Value of STCs:* the national Small-Scale Renewable Energy Scheme (SRES) provides a financial incentive to individuals and small businesses who install small-scale renewable energy systems. Installation of approved systems creates STCs, which most PV owners assign to their installer for a discount on their system;
- *Export revenue:* the revenue generated by exports to the grid depends on the volume of exports multiplied by the rate at which the electricity retailer pays the solar PV owner for each kilowatt hour exported (the feed-in tariff); and
- *Import savings:* under a net metering arrangement, solar generation reduces the monies paid to electricity retailers when household or small business energy demand is met by solar generation rather than imported. The size of the benefit is the reduction in imports multiplied by the variable charge component of the retail tariff.

2.5.1 Payback period

Advertised payback times for solar PV systems can vary significantly. These variations can be caused by the differing assumptions (for example, assumed in-house/export percentages), initial costs (these can vary greatly depending on quality), efficiency and expected degradation of the system, and opportunity costs just to name a few.

Table 7 provides estimates of electricity saving, payback period and internal rate of return (IRR) as an example of what a consumer may achieve. These estimates have been based on a conservative set of assumptions that can be found in Appendix D.

[24] Department of Energy & Climate Change (UK) 2015, p. 9.

Table 7: Solar PV system: Electricity saving, payback period and internal rate of return estimates

System Size	Total Cost*	LCOE** (c/kWh)	Retail Price (c/kWh)	Feed-in Tariff (cents)	Energy exported to grid – 30%			Energy exported to grid – 50%		
					Total Electricity Savings	Payback Period: (years)	Internal Rate of Return (IRR) %	Total Electricity Savings	Payback Period: (years)	Internal Rate of Return (IRR) %
3 kW	$6183.00	12.23	24	6	$18,096.19	10	10.43%	$12,310.06	13	6.14%
				10	$19,149.06	10	11.28%	$14,064.85	12	7.74%
3 kW	$6183.00	12.23	17	6	$11,114.71	14	5.03%	$7323.30	19	1.34%
				10	$12,167.59	13	6.02%	$9078.08	16	3.29%
5 kW	$8433.00	10.01	24	6	$32,406.71	8	14.2%	$22,763.17	11	9.62%
				10	$34,161.50	8	15.19%	$25,687.62	9	11.41%
5 kW	$8433.00	10.01	17	6	$20,770.92	12	8.39%	$14,451.90	15	4.68%
				10	$22,525.71	11	9.49%	$17,376.54	13	6.75%

** Total cost includes NPV of replacement $1500 inverter after 15 years* *** Levelised Cost of Electricity*

Source: SolarQuotes 2015.

The internal rate of return (IRR) for an investment is the percentage rate earned on each dollar invested for each period it is invested. The IRR gives an investor the means to compare alternative investments based on their yield, to assess if a project should be undertaken or not. If the IRR is greater than the minimum rate of return required (the hurdle rate) by the investor then the investment would be expected to be profitable. The hurdle rate is determined by the cost of capital, in this case the return the householder could have gotten had they used that money elsewhere (for example, other investments or paying down a home loan debt). That is, if you have an IRR of nine per cent, this means that a bank account would need to be paying nine per cent interest after tax and fees, to provide you with an equivalent return.

The financial benefit of a solar PV system is the combined savings of the reduced electricity bill plus what is received from the exported energy. The above examples illustrate that feed-in tariffs are not the primary financial benefit of solar PV. The primary financial benefit is lower electricity bills from avoiding the purchase of retail electricity. This can be seen across the table as the in-house/export percentages are varied.

2.5.2 Impact of tariff rebalancing on incentives to invest in solar PV

The underlying premise for rebalancing tariffs (both retail and network) is to ensure the fixed costs of electricity supply are recovered. Rebalancing is intended to remove cross-subsidies between customers that arise when tariff structures do not reflect these fixed costs. For example, volumetric tariffs can mean solar PV customers, by reducing their demand, do not pay the costs required to service them. Assuming costs are efficient, tariff rebalancing will help ensure customers appropriately pay for what they use.

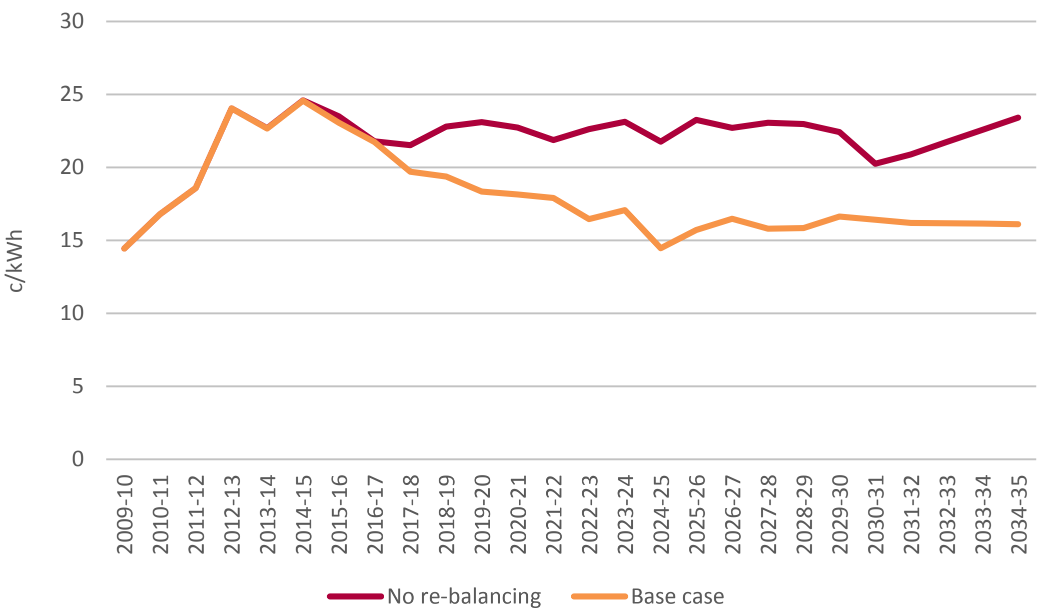
However, rebalanced tariffs, with a higher fixed charge and lower variable charge, reduce the incentive to invest in solar as it reduces the ability to avoid the cost of the retail tariff. Submissions[25] noted the impact of recent retail tariff rebalancing on the return to solar PV, with higher fixed charges eroding some of the benefits of owning a solar PV system.

ACIL Allen Consulting (ACIL Allen) modelling for this inquiry assumed that tariffs were progressively rebalanced with the variable component gradually decreasing to 20 per cent by 2030. Dropping

[25] See, for example, Solar Citizens, sub. 18, p. 3; John Davidson, sub. 17, p. 3; Dr Peter Hale, sub. 22, p. 1.

this assumption (Figure 11) raises the internal rate of return for 3.0 kW from 13.4 to 15.6 per cent, and, for a 5.0 kW system, from 14.5 to 16.5 per cent (Table 8).

Figure 11: Variable component of the retail tariff with and without rebalancing



Note: Price data in real $2014–15 terms.

Source: QPC calculations based on ACIL Allen Consulting 2015.

Table 8: Impact of tariff rebalancing on investment rate of return, 2015–16

	IRR	*Break-even (years) – Difference in average cost of consumption (c/kWh)*							
	(%)	*d.r. = 0%*		*d.r. = 3%*		*d.r. = 6%*		*d.r. = 9%*	
3.0 kW system									
Base case	13.4%	7 yrs	–7.8c	8 yrs	–5.3c	9 yrs	–3.6c	11 yrs	–2.4c
No rebalancing	15.6%	7 yrs	–10.4c	7 yrs	–7.0c	8 yrs	–4.8c	10 yrs	–3.3c
5.0 kW system									
Base case	14.5%	7 yrs	–11.4c	8 yrs	–7.9c	9 yrs	–5.6c	10 yrs	–3.9c
No rebalancing	16.5%	6 yrs	–14.9c	7 yrs	–10.3c	8 yrs	–7.2c	9 yrs	–5.1c

Notes: d.r is discount rate. The base case includes the assumption that the amount of revenue generated by retailers through fixed charges is increased over time exactly offsetting a reduction in revenues generated through variable charges (rebalancing of tariffs). Removing this assumption means that the projected variable component of the retail tariffs is increased, thereby improving the return to solar investment through increasing the benefit from avoiding the cost of imports.

Source: QPC calculations.

2.5.3 Government policies

In addition to feed-in tariffs, a number of government policies influence the uptake of solar PV. The main policy is the SRES.

Small-scale Renewable Energy Scheme

The SRES creates a financial incentive for individuals and small businesses to install eligible small-scale renewable energy systems such as solar PV systems. It does this through the creation of small-scale technology certificates (STCs).

STCs can be created following the installation of an eligible system, and are calculated based on the amount of electricity a system produces or displaces.

Consumers have two options in regard to how they can redeem STCs. Customers can sell the STCs themselves, or installers can claim them upon the purchase of the solar PV system. Most consumers choose the latter. As a result, quoted prices for nearly all PV systems have already discounted the value of STCs.

2.5.4 Metering arrangements

Feed-in tariffs can be applied on either a gross or net basis. Table 9 provides a summary of the two approaches.

Table 9: Gross versus net metering

Gross scheme	*Net scheme*
• Measure total electricity generation and in-home consumption independently • Customer paid for all generation • Customer charged for all consumption • Entire solar PV generation valued • Total consumption metered	• Solar PV generation is first used on the premises • Excess generation exported to the grid • Import and export metered separately • Export = generation minus consumption • Import = consumption minus instant generation • Customer paid for exports/charged for imports

Each metering arrangement has different impacts which will vary depending on the efficiency of network, retail and feed-in tariff prices.[26] For example, under the SBS, where the feed-in tariff was higher than retail prices, a net metering arrangement distorted incentives for efficient consumption by discouraging use during the day and shifting use to the evening peak.

Under a gross metering arrangement, all solar PV generation is multiplied by the feed-in tariff rate and then credited to the customer’s retail account and all imported electricity is charged at the customers' prevailing retail price. This method may be favoured where electricity prices are not efficient as it ensures customers pay a network charge for all of their consumption, reducing cross-subsidies between solar PV and non-solar PV customers. Ideally, however, electricity tariffs would be set efficiently, rather than constructing feed-in tariff arrangements to counteract those inefficiencies.

A gross feed-in tariff allows investment decisions to be made with more certainty. Customers are able to more accurately estimate the payments they are likely to receive under a gross scheme, as payments can be estimated without needing to know consumption patterns. As net metering depends on the behaviour of the householders, such certainty is not possible. However, assuming feed-in tariffs are set below the price of retail electricity, gross metering would also remove the primary financial benefit to owners of a PV system — avoiding the purchase of retail electricity (see Appendix D).

[26] Several submissions highlighted the impact of metering arrangements on solar PV returns. See, for example, Harold Edmonds, sub. 3 and David Brooker sub. 42.

2.6 Future growth and technology developments

2.6.1 New products and services

A range of new products and services such as solar lease and solar power purchase agreements (SPPAs) are developing within the market (Box 5). These products are helping to drive installations, and are expanding availability to previously excluded customers such as low income earners. Both solar leasing and SPPAs allow households and businesses to install solar systems without incurring large, up-front costs.

Box 5: Alternative business models and energy services supporting competition

The 'typical' retailer model: Under this model:

- the seller is the sole supplier of a fuel type (gas, electricity, or both) to a customer's premises;
- the sale of energy forms part of the seller's core business (the seller is registered with the AEMO to purchase from the wholesale market);
- the seller offers contracts for a specified short/medium period (for example, one or two years), sells the energy as a standalone service (including network and wholesale energy charges); and
- energy to the customer is delivered via regulated networks (that is, the customer is connected to the national 'grid').

Solar leasing and Solar Power Purchase Agreements (SPPAs): Both solar leasing and SPPAs allow consumers to install solar systems without incurring large, up-front costs. Under a leasing arrangement the lessee pays the lessor a fixed monthly charge. An SPPA is a financial arrangement under which a business provides, installs and maintains, at no upfront cost, a solar PV system to a customer and in exchange, the customer buys the energy provided by the solar panels for an agreed price (usually below that which would be charged by an electricity retailer) for an agreed period. In some cases, the customer owns the panels at the end of the contract.

Selling energy for a specific purpose: Some companies sell energy to customers for a defined purpose, for example, to charge an electric vehicle (EV) at the customer's home. This model involves the installation of separate meters at the premises, with the energy being sold to the customer by an EV company.

'Wheeling' arrangements: Distributed generators could generate power for their own requirements on site and sell the excess to their neighbours, avoiding the need for use of the distribution network. These arrangements are sometimes referred to as 'wheeling arrangements'.

Virtual net metering (VNM): VNM refers to when an electricity customer with onsite generation is allowed to assign their exported electricity to other site/s. The other site/s may be owned by the generator or by other electricity customers. The term 'virtual' is used to describe this sort of arrangement because the electricity generated is not physically transferred to the consumer, but rather transferred for billing reconciliation purposes only.

Information provision and other energy services: A range of businesses provide information and other energy services to customers including: price comparator websites; brokers; buying groups; and aggregators. Brokers are most active in the business market, offering services to large users where they negotiate the best deal across a range of suppliers. Brokers usually charge customers directly for their services, or accept a commission from the retailer. A buying group is where a collective negotiates on behalf of its members for the best rates between all retailers. Price aggregator sites provide similar services to government comparison sites, allowing consumers to compare different retailer offerings.

Sources: AER 2013; AER 2014a.

SPPAs are a financing option where a solar PV system is installed without up-front payment. The provider installs and maintains the system. The SPPA contract generally purchases all the electricity generated by the system, regardless of use. However, it also generally allows for the export of excess solar energy back to the grid.

2.6.2 Future solar PV growth projections

Future solar PV growth and market changes will depend on a range of factors. We engaged ACIL Allen to provide a quantitative analysis on a number of policy scenarios and sensitivities for the period 2014–15 to 2034–35. The most relevant sections for this inquiry are the base case and a group of sensitivities to examine the effect of different rooftop solar PV export prices on installation rates and retail electricity prices in Queensland.

A summary of solar PV outcomes under the base case is provided below.

Base case

The following outcomes were projected under the base case, and for each of the policy scenarios and sensitivities:

- Wholesale market outcomes — wholesale prices; generation investment, retirements and capacity; generation volumes, production cost and price by fuel type; and interconnector flows;
- Network outcomes — investment and expenditure;
- Retail market outcomes — demand, consumption and prices by customer type in Queensland; and
- Small-scale renewables and storage — costs and uptake of rooftop solar PV and storage options for residential and commercial customers in Queensland.

Table 10: Assumptions underpinning the base case

Type of assumption	*Description of assumption*
Energy/demand	• the medium energy and 50% probability of exceedance (PoE) peak demand series from the 2015 National Electricity Forecasting Report (NEFR) with slight adjustments for liquefied natural gas (LNG) timing, and assumed smelter closures • ACIL Allen's internal projection of rooftop PV, storage, and electric vehicle uptake
Supply	• ACIL Allen's internal Reference case of existing supply • new investment in generation capacity is introduced based on market signals
Policy	• no re-introduction of a price on carbon • the 33,000 GWh LRET remains unchanged and is not extended beyond 2030 • no other policy changes • network tariffs transition to recover 80% of revenue through fixed charges by 2030
Macro	• oil recovering to just under USD70 per bbl. by 2025 • coal recovering to USD75 per tonne by 2023 • the AUD/USD exchange rate stabilising at 0.75 • inflation stable at 2.5%

Source: ACIL Allen Consulting 2015.

Projected rooftop solar PV

The base case assumes that the solar PV export price is based on the cost avoided by a retailer, which is assumed to be the wholesale cost to supply the net system load profile (NSLP) in the Energex region, adjusted for network losses.

Box 6: ACIL Allen modelling methodology

Uptake of solar PV

The rapid increase in installations of rooftop solar PV systems at the household level has not only changed the growth rate in energy and peak demand to be satisfied by centralised generation sources, it has also changed the shape of the daily demand profile by shifting the time of the peak demand from mid-afternoon to late-afternoon / early evening.

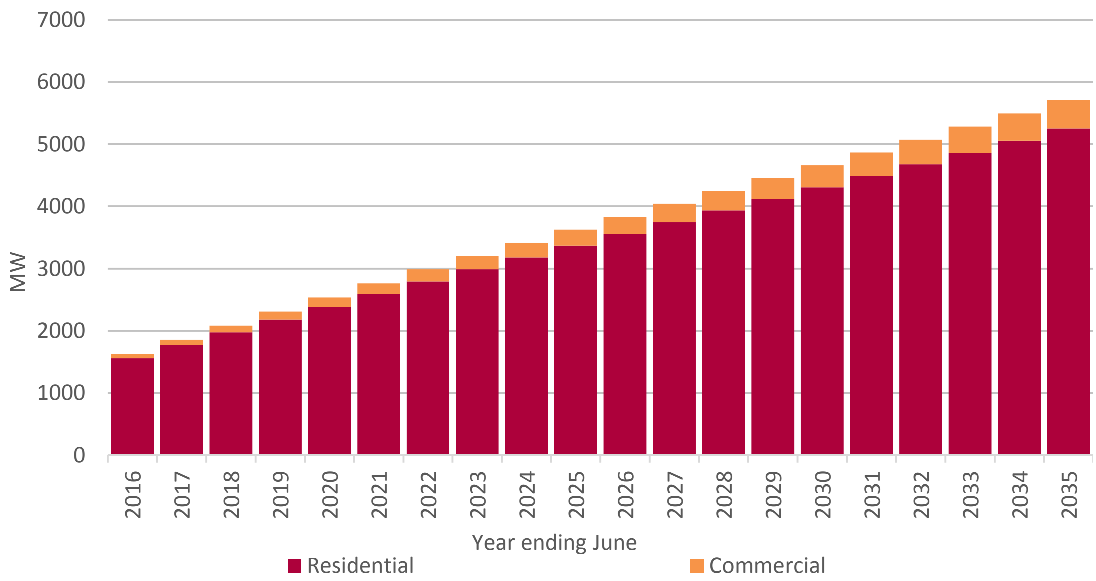
ACIL Allen has developed a model of the uptake of rooftop solar PV for each region of the NEM and Mt Isa. ACIL Allen's forecasts for uptake of roof-top solar installations are based on an econometric model relating historic investment to historic net financial returns from installing solar PV systems. This historic relationship is then applied to the forecast level of net financial returns (as a function of various key drivers) to project the future uptake of solar PV for both the household and commercial sectors. The uptake is measured as a percentage of penetration which means that the modelling approach can take into account different projections of dwellings and commercial properties — depending on the underlying economic scenario.

The modelled uptake is converted to a projected time of day output which is then deducted from the projected demands to give a set of demand projections properly accounting for the effect of future solar PV installations.

Source: ACIL Allen Consulting 2015.

Under base case assumptions, the modelling projects rooftop solar PV installations in Queensland to increase from its current 1500 MW to approximately 5700 MW (Figure 12). Rooftop PV capacity will reach the Queensland Government's 3000 MW target by 2022.

Figure 12: Projected capacity of installed small-customer rooftop PV (MW) in Qld — base case



Source: ACIL Allen Consulting 2015.

Over time, the rate of installations is tempered by:

- the declining number of households and commercial customers without PV (those without PV have less incentives to install PV due to their energy usage and profile); and
- the assumed transition to more cost-reflective network tariffs with a lower proportion of network revenue recovered through variable charges. This will reduce the cost a household or business avoids when installing rooftop solar PV.

Projected financial returns to solar PV

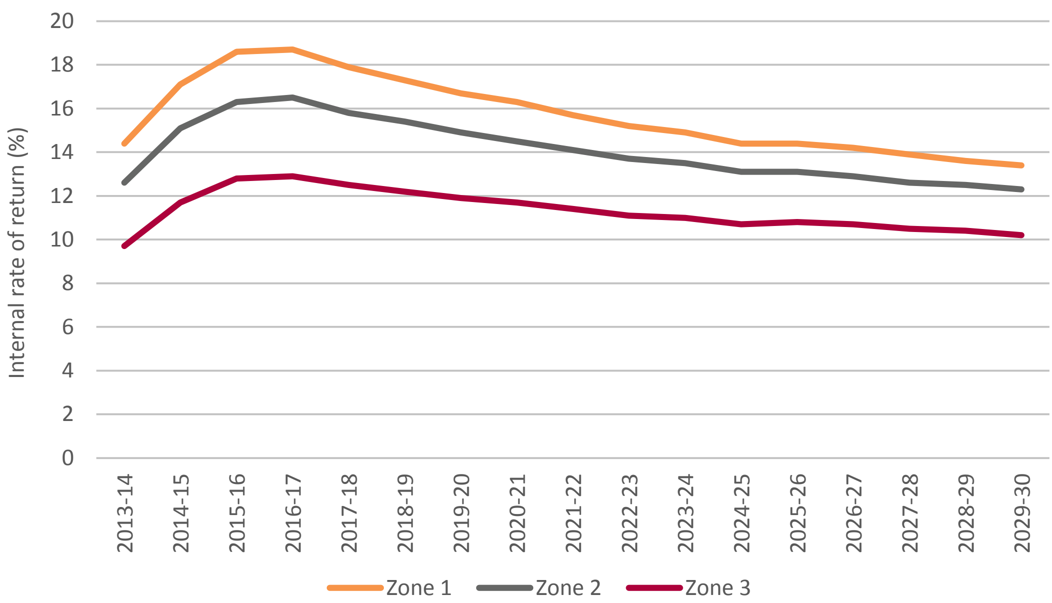
For a 4.0 kW system installed in 2015–16 in postal zone 1, the estimated internal rate of return to investment, under all base case assumptions used in the modelling by ACIL Allen is 18.6 per cent. For a system installed in postal zone 3, where the majority of Queensland's population resides, the return is 12.8 per cent.

Over time, the estimated internal rates of return gradually decrease, but still provide a return attractive to household investors.

The main trends driving the pattern of returns are:

- initially increasing retail prices;
- a gradual decline in the level of subsidy provided through the SRES;
- over the longer term, wholesale price increases raising feed-in tariffs; and
- over the longer term, tariff rebalancing reducing the financial benefits households receive when they reduce their consumption from the grid.

Figure 13: Internal rate of return to a 4.0 kW system in different postal zones



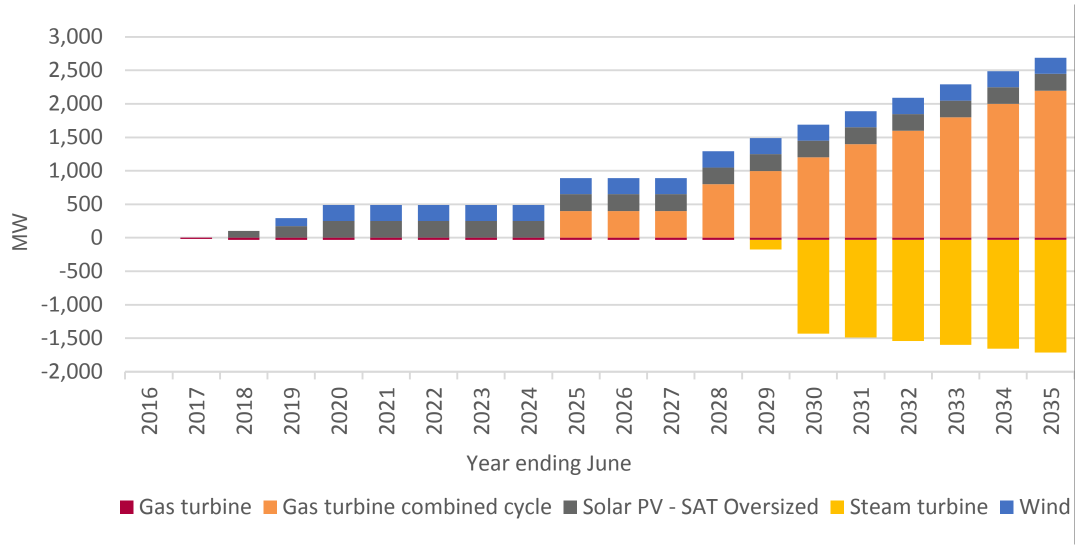
Source: QPC calculations based on ACIL Allen Consulting 2015.

Projected change in plant capacity

As the NEM is currently oversupplied, only wind capacity (around 5500 MW) is projected to enter the market prior to 2022, driven by the RET policy. About 250 MW of the new investment in wind is projected to occur in Queensland (Figure 14).

Wholesale electricity prices are insufficient to result in investment in large scale solar plant, beyond the assumed 500 MW of capacity introduced in response to various additional assistance from Australian Renewable Energy Agency (ARENA), Clean Energy Finance Corporation (CEFC) and state government policies. Essentially, large-scale solar is the victim of the success of rooftop solar PV. The growth assumed in rooftop solar PV installations carves out demand during daylight, reducing the profitability of large-scale solar in the NEM.

Figure 14: Cumulative change in installed capacity (MW) in Qld — base case (scheduled and semi-scheduled)



Source: ACIL Allen Consulting 2015.

Battery storage

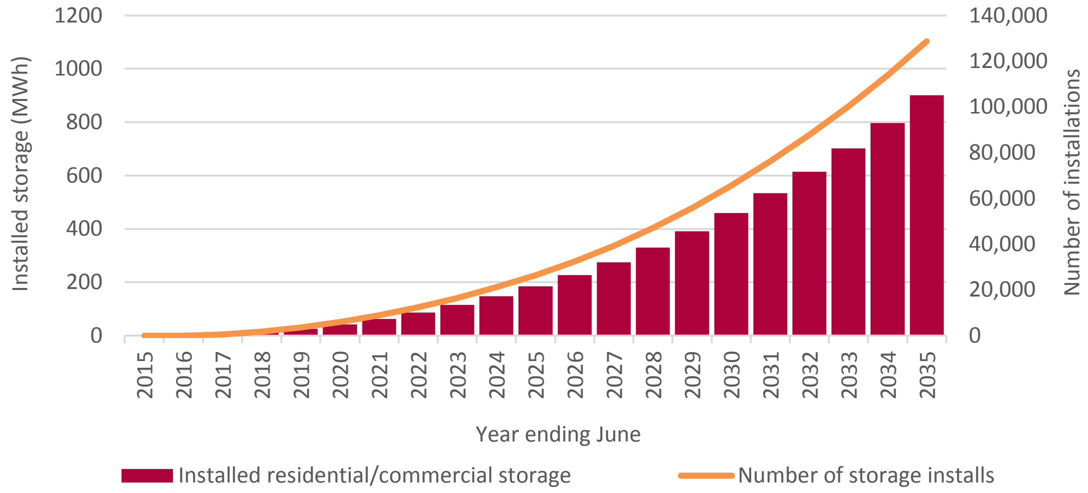
Between 2007 and 2014, the cost of battery storage fell by 14 per cent each year on average, from around US$1000/kWh to US$410/kWh.[27] Through economies of scale, innovations in chemistry and supply chain optimisation, battery prices are expected to fall by a further 50 per cent by 2020.[28]

It is likely that cheaper batteries will incentivise the future uptake of integrated energy storage systems across Australia. By combining solar PV generation and storage, users are able to offset consumption during peak periods, remedying the asymmetry between solar generation and energy usage patterns. With lower returns from exported energy, it becomes more attractive for households to store surplus solar output in a battery storage unit for use in the evening.

The modelling conducted by ACIL Allen has projected increasing installations of household and commercial storage as system costs continue to decline. Storage installations are expected to reach 129,000 with installed capacity of approximately 900 MWh (Figure 15). Storage without embedded local generation is not economic before 2035.

[27] Nykvist & Nilsson 2015, pp. 329–332.
[28] See, for example, Shallenberger 2015.

Figure 15: Projected capacity of installed battery storage (MWh) (residential and commercial)



Source: ACIL Allen Consulting 2015.

2.7 Conclusion

Solar PV in Queensland has experienced a period of rapid growth, and is now moving into a more stable growth period. The trend in feed-in tariff policy, both nationally and internationally, has been a shift away from premium feed-in tariffs towards more market-driven responses.

The key factors impacting solar PV investment are system costs and electricity prices. A further reduction in system prices, and the savings available from avoiding retail electricity charges, will be the primary driver of solar PV uptake in Queensland. Non-premium feed-in tariffs have a small impact.

The future of solar PV in Queensland is generally positive with installed capacity expected to reach 3000 MW by 2022 without any changes in current policy. The industry is expected to continue growing through new products and services and the falling prices of batteries.

3 A FRAMEWORK FOR ASSESSING A FAIR PRICE FOR SOLAR EXPORTS

The terms of reference ask us to provide advice on a fair price for exported solar energy. As fairness is a subjective concept, it is necessary to establish a framework for assessing solar export pricing. This chapter discusses the nature of fair pricing and sets out a framework for assessing solar export pricing in Queensland.

Key points

- Central issues for this inquiry are to determine what a fair price for solar exports is, when government should intervene in solar export pricing and which principles should guide that intervention.
- There is a role for government in solar export pricing only where market failures are present. Policies must be designed in a way to induce socially valuable change, provide the right incentives and avoid unintended consequences; their benefits must also outweigh their costs.
- Views on fair pricing are subjective. When fairness is used in policymaking, it is best defined by objective criteria. Proposed criteria for this inquiry are efficiency, equity, neutrality, simplicity and robustness.
- Alternatives to the policy assessment framework that generally involve variations of deterministic price setting (such as a feed-in tariff based on the retail tariff, rate-of-return tariff or 'value stack' tariff) face a significant risk of regulatory failure.

3.1 Context

If, when and how governments should intervene in solar export pricing has been a matter of considerable community interest and policy debate over the last decade. Some solar PV owners strongly support government regulating feed-in tariffs:

> *We need a fair feed-in tariff and some assurance about costs into the future. Many people went into debt to pay for their systems. I believe the government has a responsibility to continue to support those who were encouraged into the solar market as a direct result of their policies.*[29]

Others urged caution:

> *Given that Government subsidies are eventually paid for through higher electricity bills, CCIQ is wary of the introduction of new rebates. CCIQ implores the state government to learn from past mistakes so Queensland small businesses are not further burdened with higher costs.*[30]

Some views have been compounded by the impacts of electricity tariff changes and price increases:

> *[W]e have gone from having a large credit on our Ergon bill at the end of each quarter to barely breaking even and sometimes having to pay bills again. This is primarily because of the added fees and charges but also because of price rises.*[31]

[29] Julie Davies, sub. 14, p. 1.
[30] CCIQ, sub. 21, p. 8.
[31] Julie Davies, sub. 14, p. 1; also see Gary Reid, sub. 6, p. 1.

There are pockets of emotive opinion on solar feed-in-pricing, reflected in some submissions using expressions such as 'ripped-off' and 'morally wrong'. Views on solar feed-in pricing were also influenced by views on the broader — often polarised — political and policy debate on climate change.

Within this context, a solid policy framework for considering solar feed-in pricing is crucial. But there were indications of a lack of clarity on what fair solar feed-in pricing policy is supposed to achieve, and how any policy responses should be assessed and designed, to maximise the benefit to the Queensland community.

The absence of a well-defined policy framework risks:

- subjective assessments as to what is fair or unfair for feed-in tariffs;
- arbitrary views as to what should or should not be included in feed-in tariffs; and
- costs and unintended impacts from poor feed-in tariff policy or design.

Good policy outcomes are more likely where they are developed under a well-designed policy framework. A robust framework that requires policymakers and regulators to clearly identify the problem they are targeting, and to consider all potential costs and benefits (under existing and future market conditions), increases the probability that a policy will provide net benefit to the Queensland community. Policies without clearly targeted problems and objectives are more likely to result in the direction of resources from higher-value uses to lower-value uses, in addition to the resources consumed by the policy process itself.

A solid policy framework is particularly important for solar feed-in pricing, where regulatory pricing decisions can result in 'winners and losers' in the Queensland community.

3.2 Policy design process

Steps to follow in good policy design include: specifying the rationale for government intervention; examining the nature and causes of a policy problem; setting out costs and benefits of each policy option and identifying a preferred policy response.

A stylised policy development process is presented in Figure 16.

The starting point to develop any policy is to identify and assess the size and scope of the policy problem the government is trying to address. Understanding the nature of the problem is fundamental to determine an appropriate response and has a greater chance of better targeting the problem in the most effective and efficient way. For example, is the market delivering a fair price? If not, why?

If a case for government intervention has been established, the next step is to identify clear objectives. Clear and well-defined objectives help support the development of policy and regulation that targets the identified problem and minimises unintended side effects. They also provide all stakeholders and the community with a transparent understanding of the aim of the policy and a reference point to measure its appropriateness and effectiveness over time.[32]

[32] QCA 2015d.

Figure 16: Policy development process

The third step is to identify and assess all feasible options for achieving policy objectives. Governments have a range of policy tools available — from providing information (for example, energy efficiency information programs), establishing markets, setting regulatory targets and price regulation (such as feed-in tariffs). The costs and benefits of policy options (incorporating economic, environmental and social impacts) should be considered. Where a regulatory option is proposed, it should be assessed in accordance with best practice regulatory principles (Box 7) and the Queensland Government's Regulatory Impact Statement (RIS) System Guidelines.

Box 7: OECD principles for regulatory quality

The Organisation for Economic Co-operation and Development (OECD) principles of good regulation require regulation to:

- serve clearly identified policy goals, and be effective in achieving those goals;
- have a sound legal and empirical basis;
- produce benefits that justify costs, considering the distribution of effects across society and taking economic, environmental and social effects into account;
- minimise costs and market distortions;
- promote innovation through market incentives and goal-based approaches;
- be clear, simple, and practical for users;
- be consistent with other regulations and policies; and
- be compatible as far as possible with competition, trade and investment-facilitating principles at domestic and international levels.

Source: OECD 2005.

The final step is to identify the policy option that maximises the net benefit to the Queensland community.

3.3 When is solar export pricing a policy problem?

Prices for goods and services are generally determined in the market. Prices coordinate the interactions of consumers and firms, providing signals to facilitate the production of goods and services that people value. Prices ration supply amongst consumers according to willingness to pay and indicate the opportunity cost of resources used in the production of goods and services. In a competitive market, efficient prices ensure the goods and services consumers value most will be produced at the lowest cost, maximising community welfare (Box 8).

However, markets are not always efficient. A number of market failures may be relevant to solar exports, including:

- *Lack of effective competition:* where there is a natural monopoly or when the market has a small number of firms that can use their market power to materially reduce community welfare. For example, in regional Queensland, Ergon Energy (Retail) is typically the sole retailer of electricity to small customers and the sole purchaser of exported solar energy.
- *Environmental externalities:* where the actions of an individual or business create environmental benefits or costs on others and these effects are not reflected in market prices. For example, where solar PV displaces fossil fuel generation and this provides an environmental benefit, and the benefit is not compensated.
- *Imperfect or asymmetric information:* where one party has more information about a transaction than the other, or where barriers prevent parties to a transaction from obtaining relevant information about the characteristics of a transaction and/or each other. For example, suppliers, electricity market participants and consumers may face informational constraints concerning the impacts of solar PV.

Box 8: Welfare and economic efficiency

Economic efficiency is about maximising the aggregate or collective wellbeing of the members of the community. An economically efficient outcome is attained when individuals in society maximise their utility, given the resources available in the economy. This is called Pareto efficiency. With this allocation of resources no one can be made better off without making someone worse off, nor could the winners from a reallocation compensate the losers (Kaldor's extension of Pareto efficiency).

There are three aspects of economic efficiency:

- *Productive efficiency* is achieved where individual firms produce the goods and services that they offer to consumers at least-cost.
- *Allocative efficiency* is achieved where resources used to produce a set of goods and services are allocated to their highest valued uses.
- *Dynamic efficiency* reflects the need for industries to make timely changes to technology and products in response to changes in consumer tastes and in productive opportunities.[33]

From a policy point of view, an activity is efficient if the benefits it provides exceed the costs (including all costs and benefits associated with environmental and social externalities) and there is no other use of resources that would yield a higher value for the community. In terms of policy and regulatory design, it requires policymakers to identify the efficient option — the outcome, policy or regulation that results in the highest net benefit to the community as a whole.

The presence of these market failures provides an in-principle case for government intervention.

However, the presence of market failures alone do not justify government intervention. Individuals, organisations and industry may find solutions to market failures, reflected in the large number of community-based, not-for-profit and private sector activities related to environmental issues. For example, the Clean Energy Council publishes a range of solar PV information and guides to help address information imbalances.

Moreover, intervention must be designed in a way that the benefits exceed the costs. Government intervention may be unsuccessful, introduce new inefficiencies, have unintended impacts and impose compliance and administration costs. Getting it wrong, particularly where price regulation is involved, can be very damaging to the community (Box 9).

[33] Committee of Review 1993, p. 4.

Box 9: Price regulation for fairness: Challenges and costs

Regulating for fairness holds the promise of providing a fair return or protecting groups in the community, but by removing price signals it can distort resource allocation and cause shortages or surpluses. For example, there are a large number of international examples where governments have attempted to regulate the price of bread or fuel to protect low income earners. But lower prices have reduced supply, meaning that although some consumers could purchase at a lower price, others are left with no supply at all.

Historically, the Australian, State and Territory governments were involved in a range of price regulation activities. Some of these activities were, at least in part, ostensibly aimed at ensuring prices were fair.

Interest rate controls: Until the mid-1980s the Australian Government set an interest rate ceiling for home loans as part of its broader suite of monetary regulation and wide spread beliefs that interest rates should be kept low. The consequence was for banks to ration credit, with credit worthy lower income earners, single parent families and women often excluded from borrowing from banks. To access credit, these groups had to seek loans from alternative, more expensive sources.

The 1981 Campbell Committee concluded:

> *[I]nterest rate controls are an inefficient and ineffective means of assisting low-income potential homebuyers. They have regressive distributional consequences, harming many they are intended to benefit and benefiting many who do not require assistance. In short, they can be said to have been counter-productive in achieving their welfare objectives while hurting the community at large by impairing the efficiency of the financial system.*

Wool reserve price scheme: In response to rapidly declining wool prices in the late 1960s and early 1970s, the then Australian Government introduced a reserve price scheme for wool to protect wool growers from market fluctuations. Under the scheme, the Australian Wool Corporation (AWC) set minimum prices for different categories of wool and then used grower funds to buy wool that did not reach the prescribed price, aiming to hold it until the market improved.

Initially, the scheme appeared to ‘work’ and prices stabilised from 1974 to 1987. But by the late 1980s, market conditions had changed. The floor price had been set too high, and as a result, the AWC had amassed a stockpile of 4.75 million bales of wool, with an associated debt of $2.6 billion. The scheme failed because its key requirement — knowledge of how the long-run, market-clearing price related to observed prices — was unavailable to the scheme’s administrators, who also faced systematic incentives to overestimate the price.

In 1991, the reserve price scheme was scrapped. For a short time, wool growers were paid a government subsidy to kill their sheep. It took over 10 years to sell the last bale from the wool stockpile.

Source: Committee of the inquiry into the Australian Financial System 1981; PC 2010.

For these reasons, government intervention in markets, particularly through price regulation, is generally confined to areas that exhibit substantial and enduring market failures, where there is no alternative policy and non-policy options to deal with those market failures.

Chapters 4 and 5 assess the case for regulating feed-in tariffs to address market power or environmental externalities. Chapter 6 assesses the case for regulating feed-in tariffs for a range of other reasons including wider economic benefits and wholesale and network market impacts.

3.4 What are fair prices?

The terms of reference ask us to investigate 'a fair price for solar energy generated by a small customer and exported to a Queensland electricity grid'. As fairness is subjective (Box 10), there are differing views on what would be a fair price for solar exports.

Box 10: Perceptions of fairness

Perceptions of fairness are inherently subjective. As Handler points out:

> *What was fair yesterday may be unfair today. What is deemed unfair by one group of business men may be regarded as eminently proper by another. What is offensive to a commission may be palatable to the courts. There are other variables. Practices that are economically justifiable in one industry may be reprehensible in others. What is harmless to competitors may be harmful to consumers and vice versa.*

Empirical research suggests that some of the factors that influence perceptions of fairness include:

Reference prices — prices equal to prices of competitors or prices in the recent past are considered to be fairer than prices that strongly deviate from these reference prices. This is particularly the case where the price changes for the same product (such as electricity prices rises and solar feed-in tariff reductions) or where the price paid differs across customers.

The inferred motives of the seller — where a business is viewed as pursuing social goals, rather than profits, prices are more likely to be viewed as fair. In the same way, high executive remuneration is more likely to be deemed unfair compared with high salaries to sports stars or actors.

Self-interest — if a person is involved in the transaction (either as the buyer or seller), the price fairness is determined by the way in which that person benefits from it. For a seller, the higher the price they get the more they consider the price fair. In the case of solar feed-in tariffs, solar PV owners are more likely to view higher tariffs as fair and lower tariffs as unfair.

Equity — price increases are judged to be fairer if they benefit low-income or small agents than if they benefit high-income or large agents. For example, if a price increase flows to low income farmers in developing countries it is more likely to be deemed as fair.

Source: Handler 1936 in QCA 2013b; Gielissen et al. 2008.

Both solar PV owners and electricity customers have expressed concerns with the fairness of solar pricing arrangements:

> *If the State Government wishes to encourage householders to install rooftop solar it must address the inequity of the FiT. From the point of view of an ordinary consumer, the rates are totally out of balance and the disparity extremely unfair. The disparity cries out for an explanation.*[34]

A number of stakeholders felt that it was unfair for non-solar customers to pay for feed-in tariffs:

> *Why don't you reduce the closed subsidy for solar feed-in which expires in 2028 … what a joke … A reasonable refund to these customers would have to be the same as tariff 11 not 44 cents as they now get (…) Isn't it about time you started looking after the low income earning?*[35]

Solar Citizens conducted a survey of 685 people (95 per cent of which were solar PV owners) to ask what they considered a fair price for solar exports to be:

> *Approximately one-third (28%) of respondents thought a fair price was between 40 and 50c/kWh, another third thought that a fair rate would be the same rate that retailers buy electricity on the wholesale market and the remaining respondents were split or fielded 'other' responses. These 'other' responses included responses such as "1:1 parity" or "market + 50%".*[36]

The Australian Solar Council felt any unregulated feed-in tariff was unfair:

> *the current system where a home or small business owner has to negotiate with the utility on the rate of their feed-in tariff is demonstrably unfair and unjust given the power imbalance.*[37]

Others argued that:

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[34] Ralph Carlisle, sub. 2, p. 1.
[35] Caroline Slager, sub. 8, p. 1; see also Harold Gossner, sub. 12, p. 1.
[36] Solar Citizens, sub. 18, p. 2.
[37] Australian Solar Council, sub. DR23, p. 3.

> *determining a feed-in tariff that satisfied a level material enough to be considered fair for some stakeholders will invariably require subsidies from non-solar electricity customers. Such an approach would contravene the Government's terms of reference.*[38]

In a market, the value of a good or service is not determined by either any inherent property of a good or service or the cost of its production. Rather, the value of a product is determined — or revealed — through the process of buyers and sellers seeking to exchange (trade) to improve their own welfare, each having their own valuation that they place on the good or service.[39]

Buyers would prefer to pay less for a good or service so that more income was available for other things. Sellers would prefer to obtain a higher price for the same reasons. Being happy or disappointed in a price implies little about its fairness. Consequently, when fairness is used in policymaking, it is best defined by some objective measure.

3.4.1 Principles for assessing feed-in tariff options

Efficiency

In several ways, efficient prices can be described as fair prices:

> *[P]rices that reflect the cost to society of producing a good or service is fair in the sense that lower prices would imply that the beneficiary is not paying a fair share. Prices above [efficient] cost imply that the producer is receiving a benefit at the expense of the consumer.*[40]

The Council of Australian Governments (COAG) National Principles for Feed-in Tariffs states that micro renewable generation should receive fair and reasonable value for exported energy. Governments agreed that payment for solar exports should be:

> *at least equal to the value of that energy in the relevant electricity market and the relevant electricity network it feeds in to, taking into account the time of day during which energy is exported.*[41]

Similarly, the National Electricity Objective under the National Electricity Law provides guidance for all policy measures that influence the NEM. The objective is:

> *to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to – price, quality, safety, reliability, and security of supply of electricity; and the reliability, safety and security of the national electricity system.*

Economically efficient solar export pricing would send price signals to both consumers and suppliers of electricity to support efficient outcomes. The price would signal to consumers the costs of providing energy so that consumption occurs when consumers value the energy more than or equal to its cost of supply. Suppliers would receive information which informs their production and investment decisions so that investment occurs when, where and in the firms and technologies that can more efficiently meet consumer demands, compared to alternatives. An efficient price would also support the efficient operation and use of existing assets.

Efficiency also embodies a 'user pays' approach, where individuals or businesses that use a good or service pay the cost of that good or service. Moving away from efficient pricing results in subsidies or cross-subsidies. The COAG National Principles for Feed-in Tariffs require governments to limit policies that result in cross-subsidies between customer groups. Where governments wish

[38] Origin Energy, sub. 24, p. 9.
[39] Menger 1871.
[40] QCA 2013b, p. 21.
[41] COAG 2012.

to subsidise a particular group, they must explicitly consider providing the subsidy directly through government expenditures.[42]

If cross-subsidies are in place, some businesses or consumers are paying for benefits enjoyed by other businesses or consumers (that is, a cross-subsidy cannot assist one person without harming another).

Equity (distributional impacts)

Assessing fairness also involves consideration of the distributional impacts of a policy. The terms of reference for this inquiry require a fair price that is based on the benefits of exported solar energy but 'does not impose unreasonable network costs on electricity customers; particularly vulnerable customers'.

Equity is difficult to define, but for policy assessments it is often characterised as treating individuals in similar circumstances equally and treating individuals in different circumstances in proportion to their differences. It can be framed in terms of vertical and horizontal equity:

- Vertical equity implies that policy should take account of different individual circumstances (for example, in general, individuals that have a higher income should contribute more and pay more tax than those who have a lower income).
- Horizontal equity requires that individuals in similar circumstances should be treated equally (for example, individuals with similar income and assets should pay the same amount in taxes).

Subsidies can raise equity issues, for example, if they are funded by taking a dollar from a non-solar, low income household and transferring it to a high income household with solar. Even if subsidies are paid from government revenues, it also involves both winners and losers because government revenues are raised from households and businesses.

Neutrality

Policy frameworks typically include a principle that policies should be technology-neutral. Technology neutrality means that what is important is the quality and price of the service, not the specific platform, technology or approach to delivering the service.

Neutrality ensures the focus is on the long-term interests of consumers and not the industry or the development of a specific technology. This is consistent with the finding that welfare is maximised through functioning markets where customers determine which supply option best meets their needs and budget, thereby determining which technologies contribute the most to welfare improvement. Policy or regulatory attempts to 'pick technological winners' risk damaging industry development, resulting in lower-quality or higher-priced services being offered to consumers.

A number of objects of the *Electricity Act 1994* are consistent with the idea that regulations should not distort competition between alternative solutions to supplying a service. In the context of solar exports, a technology neutrality principle would require that regulated feed-in prices neither advantage nor disadvantage any particular suppliers based on the technologies used to generate energy.

[42] COAG 2012.

Simplicity, transparency and robustness

Perceptions of fairness are influenced by more than just the specific level of the price paid for a good or service. Where prices are regulated, some aspects of how prices are determined and changed can influence perceptions of fairness, such as whether regulatory governance is transparent, accountable and the minimum required to achieve the desired outcome.

Similarly, where households and businesses make capital investment decisions, the conditions under which investments are made can influence perceptions of fairness when subsequent changes occur (for example, changes to policy or regulatory settings which alter the returns to an investment). Conversely, where policies are retained to support investor certainty, but have adverse impacts on other groups of Queenslanders, this also has fairness implications.

Where feed-in tariffs are regulated, the method for calculating the prices should be as simple as possible. This will improve transparency and consumer and industry understanding of how the prices are determined. The scope will therefore be much smaller for misunderstandings and perceptions of unfairness.

Solar PV owners, industry participants and electricity consumers need to have strong confidence in the robustness of the feed-in tariff estimates determined by a regulator. This implies limitations on the matters that can realistically be taken into account in determining prices. Where there are highly uncertain impacts of policy relevance, or where impacts cannot be reliably quantified, it may be best to address these impacts through alternative policy instruments rather than impact the development of electricity markets.

Confidence in cost and price estimates is improved when estimates can be externally replicated. This suggests that the models and data used to produce the estimates should be made publicly available as part of normal consultation processes.

3.5 Alternatives to the policy framework

The majority of stakeholders to this inquiry supported the framework for solar export pricing policy set out in the Draft Report and reflected in this chapter. However, some submissions proposed more deterministic approaches to solar feed-in pricing, whereby solar feed-in tariffs are set such that:

- Solar PV owners sell exports for the retail price of electricity (a 'one-for-one' tariff);
- Solar PV owners receive a minimum rate of return on their investment;
- Feed-in tariffs reflect the importance of solar PV to the Queensland community; or
- Feed-in tariffs incorporate a payment for all potential impacts (a value stack approach).

3.5.1 Feed-in tariff equal to the retail tariff (one-for-one tariff)

A feed-in tariff set to the retail tariff means solar PV customers would be paid the retail electricity price for the energy they export (that is, solar PV owners would sell electricity for the same price that they purchase it). Many solar PV owners advocated for feed-in tariffs to be set to the retail price:

> *At the very least we should be paid for our solar at the same rate we are charged for power.*
>
> *Solar deserves a fair price because many of these homeowners including myself have spent a considerable amount of money on both purchasing their solar system and also the upkeep of this, yet still have to pay a considerable amount of power for electricity via the power grid. As a result it*

> *would be much more fair to these users if they were paid the same rate for every KWH generated that they paid for from the grid.*
>
> *I believe that the solar feed in rate should be square. By this I mean the energy Co. sells it to me for $0.26c you buy it off me for $0.26c I can't see why this isn't fair!!!*[43]

The problem with setting a feed-in tariff to the retail price is that the electricity purchased from solar PV owners is not the same product that consumers purchase from retailers. Solar exports are a form of electricity generation (akin to other electricity generation in the wholesale market), whereas a retail product bundles network and other services as well as green scheme costs.

There is a consensus from regulators in Australia that when retailers purchase electricity from solar PV owners they do not 'save' the retail price of electricity:

> *When solar electricity is exported to the grid, retailers can save on the amount of electricity they need to purchase from the wholesale electricity market. However, retailers cannot avoid incurring certain costs on this electricity such as network, green scheme and retailing costs. These costs represent a substantial portion of the total cost of providing retail electricity. Therefore, the value of PV customers' exports to retailers is considerably less than the retail price.*[44]

In Queensland, electricity retailers incur a range of costs that they are required to pay regardless of where or how the energy is generated. When an electricity retailer purchases solar exports, it essentially acts as a financial intermediary between the household that produces the electricity and the household that uses the electricity. The financial benefit to the retailer is the price it can charge for selling each unit of solar PV energy, less the costs it cannot avoid when on-selling that energy.[45]

If electricity retailers were required to pay the retail tariff, then they would incur a loss from serving solar PV customers (Figure 17). Put another way, if retailers have the option of purchasing electricity from a solar PV customer or the wholesale market, they would be far better off purchasing from the wholesale market.

A likely outcome would be that retailers would avoid servicing solar PV customers:

> *Requiring retailers to pay more for the energy from solar exports than what they are able to acquire from the NEM could lead to negative impacts on retail competition, for example, if retailers were incentivised to avoid solar customers or to offer solar customers market contracts with lower discounts than those offered to non-solar customers.*[46]

Alternatively, the government would need to fund the difference between the avoided cost and the retail price through budget expenditure or higher electricity prices for all customers.

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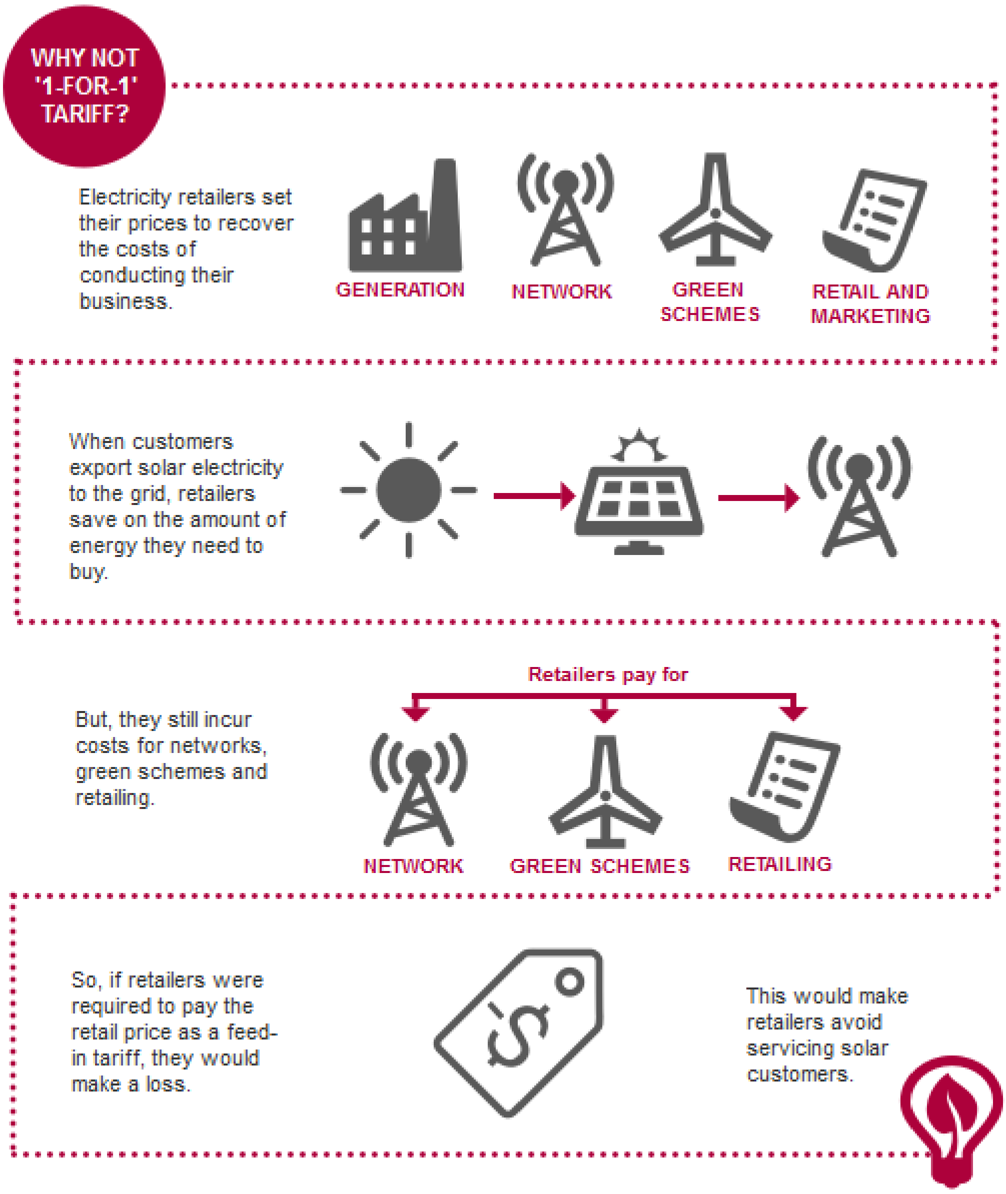
[43] Solar Citizens, sub. DR24.
[44] IPART 2015, p. 47.
[45] QCA 2013a.
[46] AGL, sub. 19, p. 2.

Figure 17: Why feed-in tariffs cannot be set to the retail price of electricity



Source: Based on IPART 2015, p. 48.

3.5.2 Return on investment tariff

The second proposal is to set feed-in tariffs so PV owners recover a minimum rate of return, as was the case in some European subsidy schemes:

> *Solar export pricing should be tailored at ensuring that the industry remains commercially viable by ensuring that investment in solar PV systems are financially viable … Tariff structures should be reflective of the costs of installing PV systems.*[47]

However, a feed-in tariff based on a minimum rate of return to solar PV owners does not relate to the value of solar PV exports. It is both inefficient and inequitable:

[47] University of Queensland, Global Change Institute, sub. 28, p. 7.

> *FiTs calculated using the payback methodology are neither efficient nor effective because they may result in a payment for the electricity exported by distributed generators that is greater than its value (either energy, network or both) or less than its value.*
>
> *Making such a payment is inequitable as it either requires whoever funds the FiT payment to pay more for the electricity generated than it is worth, or for the distributed generator to receive less for the electricity generated than it is worth.*[48]

No other generator of electricity is guaranteed a return on investment. Such a guarantee would supress incentives to produce electricity at lowest cost and likely inflate installation costs. It would divert resources away from other potentially lower cost sources of generation, including large-scale renewables or other types of embedded generation. Removing any risk on solar PV investment would encourage households to invest in solar PV even when it is not efficient to do so.

3.5.3 Tariffs based on the importance of solar PV

A number of submissions pointed to the range of potential positive impacts of solar PV:

> *In such a sunny country, solar just makes sense. The widespread economic, social and environmental advantages of solar benefit families, communities and individuals.*[49]

Sustainable Queensland[50] highlighted overwhelming public support for renewable energy, opportunities for innovation and sufficiency, economic and regional diversification and a more resilient energy supply.

Some argued that given the scope for wide-ranging benefits from solar PV, feed-in tariffs should be set to reflect the importance of solar PV.

Many goods and services bring substantial benefits to the Queensland community. How important something is, or the benefits it creates, does not determine whether governments should regulate the price for, or subsidise, a product. Nor does it provide good guidance on how any prices should be set. If it did, this logic would also support government regulating prices for, or subsidising, industries in Queensland that, for example, provide large economic contributions — such as the mining sector.

The real test is whether there is a problem that impedes socially optimal outcomes, and whether government intervention to address that problem can induce benefits that outweigh the costs.

3.5.4 A ‘value stack’ approach

Another proposed approach is to identify and measure all potential impacts of solar generation and exports which, due to one reason or another, are said to not be fully reflected in feed-in tariffs. A rate is attached to each impact and then summed into a feed-in tariff.

This approach views the problem as a series of 'optimal subsidies' to be identified and measured and then be aggregated into a feed-in tariff. The argument is that the feed-in tariff should include a component for the energy value of solar PV, plus a subsidy for emissions reduction, plus a subsidy for potential network benefits, and so on.

The Australian Solar Council advocated for this methodology to set feed-in tariffs, highlighting several studies into the value of solar PV from the United States (for example, from the National

[48] ACIL Tasman 2012.
[49] Solar Citizens, sub. 18, p. 1.
[50] Sustainable Queensland, sub. 32, pp. 7–11.

Renewable Energy Laboratory, Institute of Self Reliance and the Michigan Public Service Commission Working Group).[51]

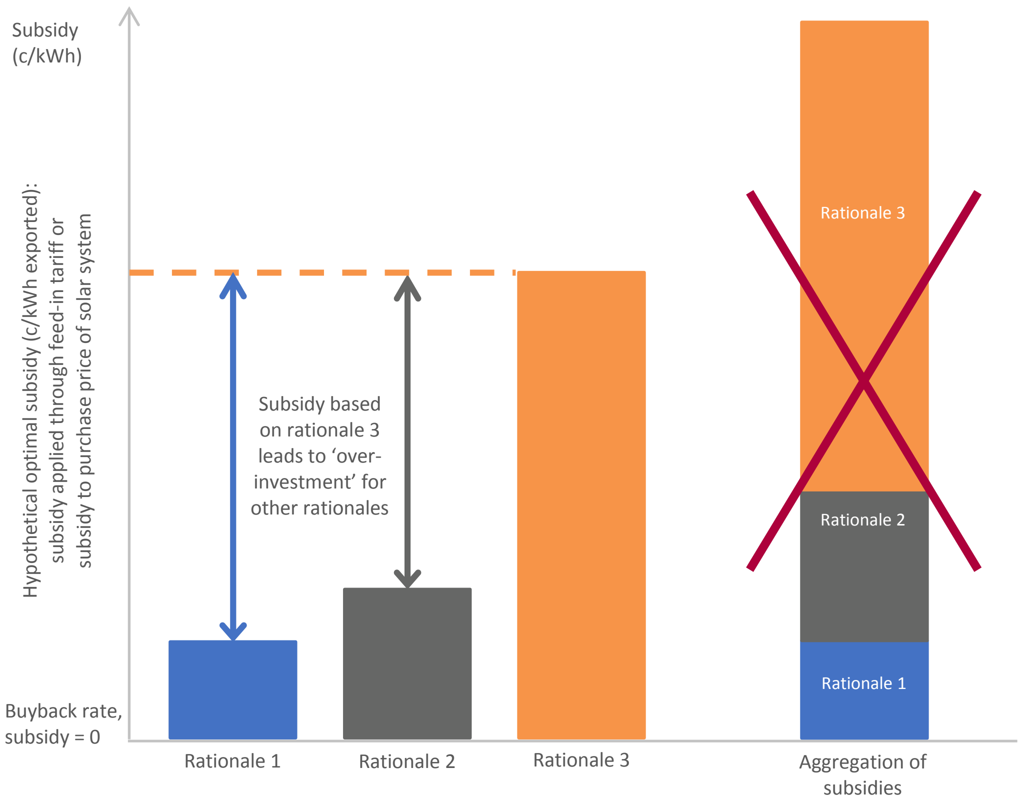
However, adopting this approach to pricing is inappropriate — while there may be a number of potential rationales for a subsidy, a subsidy changes a *single price* which impacts simultaneously on all underlying activities related to each of the rationales.

For the purpose of illustration, assume that three types of benefit are not reflected in feed-in tariffs and that empirical work has indicated that each requires a level of subsidy that implies a five-cent increase in feed-in tariffs. In this case, the policy should be a price increase of 5 cents, not 15 cents (three rationales for a subsidy multiplied by 5 cents each).

This is because for each incremental price rise, the price change has an impact across *all* of the activities for the various rationales. The upward price change might lead to marginally higher investment in solar, marginally lower emissions and marginally increase the incentives to undertake solar research and development. With prices providing a critical coordinating role in millions of transactions, the subsidy is also likely to result in unforeseen changes (both positive and negative). As a result, even where there are multiple rationales for a policy intervention to adjust a price level, the subsidies do not aggregate.

Consider a further hypothetical situation where there are multiple rationales for a subsidy, but the required magnitude of subsidy differs for each rationale (Figure 18). If the subsidy is set to achieve rationale 3, the price has been changed 'too much' based on the other rationales, leading to over-investment in solar.

Figure 18: Hypothetical subsidy: Optimal subsidies do not aggregate



[51] NREL 2014; ILSR 2014; Michigan Public Service Commission 2014.

Consequently, if all of the advocated rationales for a subsidised feed-in tariff supported some positive increase, then the optimal subsidy would likely lie somewhere between the highest subsidy required (in this hypothetical example the subsidy for rationale 3) and the lower subsidy required based on other rationales.

A 'value stack' approach to feed-in tariffs does not determine the optimal subsidy required to induce change. It would result in high transfers to solar owners and inefficient investment, with the cost of subsidies borne by the Queensland community.

3.6 Conclusion

In summary, as fairness is subjective, when used in policymaking it is best defined against objective measures. In the case of solar feed-in pricing, a fair price should be assessed against fairness for all Queenslanders, not just the outcomes for specific individuals or organisations.

Solar feed-in pricing is best assessed under a robust policy development framework that aims to ensure government policy provides the greatest net benefit to the Queensland community. Under this framework, the principles for evaluating solar export pricing arrangements are:

- Efficiency — Are the pricing arrangements consistent with achieving economic efficiency? Efficiency is broadly defined to ensure resources are allocated to their highest valued use (including accounting for environmental externalities), output is produced at minimum cost, and new processes, systems and services are introduced in a timely way.
- Equity — Are the pricing arrangements consistent with vertical and horizontal equity? If a subsidy is proposed, is there a well-developed rationale? If so, how should it be funded?
- Policy governance and practice — Where prices are regulated, is the regulatory framework transparent and robust? Is it as simple as possible and appropriately balances efficiency versus simplicity where there is a trade-off? Are policies and regulation technology-neutral?

Findings

3.1 A price for solar exports is fair when solar PV owners are receiving an efficient price for the electricity they generate – and remaining electricity consumers are not paying more (or less) than they should for solar PV energy.

3.2 Solar export pricing arrangements should be assessed against the following principles to determine whether they are fair:

(a) Efficiency — Are the pricing arrangements consistent with achieving economic efficiency? Efficiency is broadly defined to ensure resources are allocated to their highest valued use (including accounting for environmental impacts), output is produced at minimum cost and new processes, systems and services are introduced in a timely way.

(b) Equity — Do the pricing arrangements avoid cross-subsidies? If a subsidy is proposed, is there a well-developed rationale? If so, how should it be funded?

(c) Policy governance and practice — Where prices are regulated, is the regulatory framework transparent and robust? Is it as simple as possible and appropriately balances efficiency versus simplicity where there is a trade-off? Are policies and regulation technology-neutral?

4 ELECTRICITY EXPORT MARKET: COMPETITION ASSESSMENT

The main rationale for governments to mandate prices is where high levels of market power result in prices being significantly higher (or lower) than what would occur in a market where competition effectively constrains the behaviour of suppliers.

Competition assessments seek to examine the state of competition in a market to assess whether there is a rationale for regulatory intervention, or whether market conditions are such that existing regulations need reform or abolition.

Presently, the Queensland Competition Authority (QCA) is directed by the Queensland Government to set an annual feed-in tariff applying in regional areas, while feed-in tariffs in SEQ are based on retailers' market offers. This chapter assesses whether sufficient competition exists in the SEQ and regional Queensland markets to deliver fair feed-in tariffs.

Key points

- The primary reason for governments to regulate prices is to constrain the ability of a dominant firm to significantly raise — or lower, in the case of feed-in tariffs — prices compared with those that would result under competitive market conditions.
- In SEQ, the level of competition is effective in providing choice and price benefits to consumers. Competitive pressures may increase through growth in the number of market participants, growth of smaller retailers and service providers, or simply continued price reductions in solar PV panels. As a result, there does not appear to be a case for mandatory feed-in tariffs in SEQ to address market power.
- In regional areas, Ergon Energy (Retail) is the only retailer for most small customers. In the absence of regulatory intervention, Ergon would have the ability to reduce the feed-in tariff below levels that would occur in a competitive market.
- Constraints on the ability of electricity retailers to exercise market power include: the financial impacts on retailers if their behaviours further encourage their customers to invest in solar; and the development of alternative business models and energy services (such as solar power purchase agreements) which makes solar investment more accessible.
- In regional Queensland, while there are some constraints on market power, and any impact of market power on investment in solar is unlikely to be large, on balance there is a reasonable case for some form of regulation to ensure consumers receive a fair price.

4.1 Effective competition

As discussed in Chapter 3, competition between businesses helps promote fair outcomes for consumers. Market power is generally defined as the ability to raise and maintain prices above competitive levels. This can have impacts on industry output and incomes, investment, efficiency and employment and, in turn, fairness.

Market power is generally associated with monopoly providers. In a competitive market, a rise in price above long-run efficient cost, including a provision for a normal commercial profit, signals the opportunity for profitable investment. This attracts increased supply which, in turn, competes away any above-normal profits.

In markets that are highly concentrated, with significant barriers to entry, firms may be able to use market power to profitably sustain prices above the efficient cost of supply for a sustained period of time. Aside from price impacts, companies facing no competition are also generally perceived as being less responsive to customers, technically inefficient, and poor innovators (even where the monopolist's market position may have been derived by prior innovations).

Whether market power warrants regulation depends on the extent of market power and its impacts. In many situations and industries, the exercise of market power to obtain monopoly profits is not necessarily a problem, as it is an important part of the market process delivering better outcomes for consumers. Every investment in R&D by business and the introduction of an innovative product or process, or other form of innovation, is motivated by the pursuit of monopoly profit. While not 'perfect competition', competition is sufficient to ensure that these profits accrue to those who better serve customer needs, and that monopoly profits are temporary, as they are vulnerable to imitation and further innovations.

In the context of feed-in tariffs, a single buyer, or small number of buyers of solar exports, may be able to set prices below competitive levels. The degree of market power, and the extent to which it can persist, depends largely on barriers to entry and exit, and the availability to consumers of reasonably close substitutes.

4.2 Market definition

To assess the state of competition in a market, the 'market' first needs to be defined in terms of its relevant product and geographic dimensions.

4.2.1 The product market

An important issue in competition assessments is how narrow or wide to define the product market.

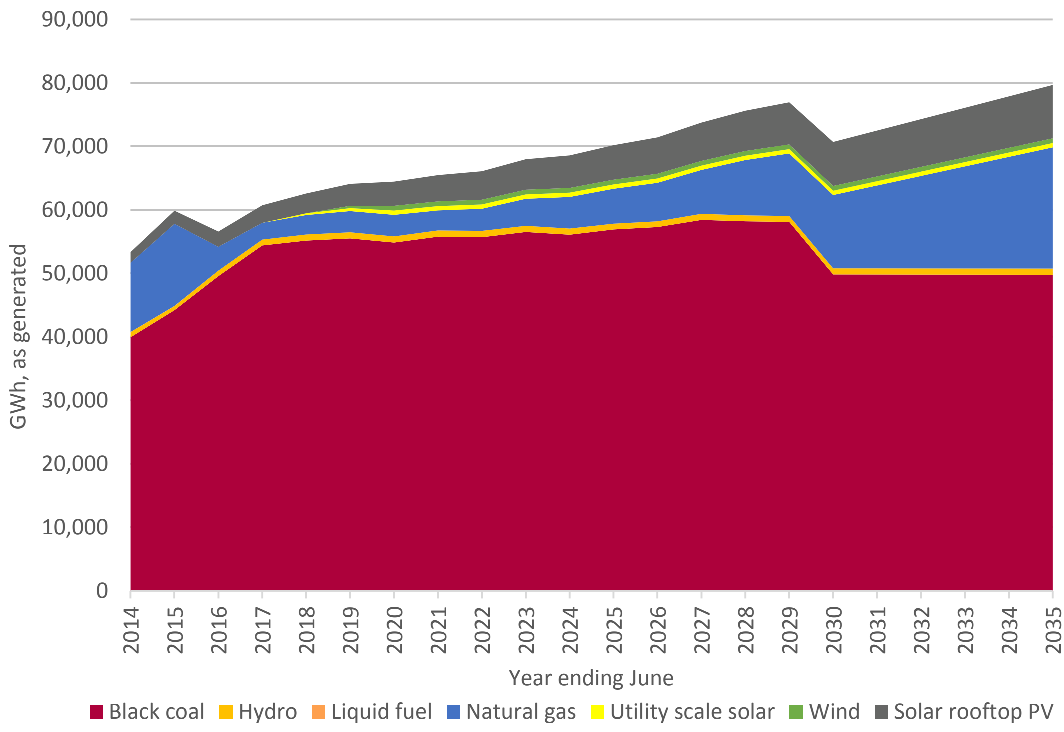
To help define market boundaries, a competition assessment considers the potential for substitution between products, as well as the scope for complementarity between products. Goods or services that are substitutes are in competition with one another. For complementary goods and services, the level of competition in the market for one good or service affects competition and price for the other good or service.

Solar exports substitute for other sources of electricity supply

The electricity generated by solar PV systems substitutes for electricity generated from other sources, including other small-scale sources and large-scale thermal plants. Solar PV generation displaces electricity from other sources whether the electricity is directly consumed by the household or business (a reduction in the demand for energy supplied by the grid), or exported to the grid (an increase in energy supplied to the grid).

Projections suggest that by 2019–20 electricity generated from solar rooftop PV systems in Queensland will displace 3805 GWh of electricity generated from other sources, and by 2034–35 it will displace 8403 GWh (Figure 19).

Figure 19: Projected Queensland electricity generation volumes by fuel type



Source: ACIL Allen Consulting 2015.

A competition assessment could define the relevant market as the market for the generation and supply of electricity.[52] The assessment would then proceed by considering the level of competition in the wholesale electricity market, which would be defined to include small-scale renewables generation. Solar PV system owners would be considered as being in competition with large-scale generators, given the clear substitution effect.

However, solar PV system owners are not in 'price' competition with generators.

Solar exporting households and businesses are not part of the National Electricity Market (NEM) arrangements for bidding in energy at half-hourly intervals and having that energy dispatched (or not, depending on the price of other supply bids). Market operations coordinated by the Australian Energy Market Operator (AEMO) take solar exports as a given (as an exogenous factor) and vary other sources of electricity supply to balance network energy demand with supply.

Nonetheless, because solar exports reduce demand for energy supplied by the NEM, solar exports can have price effects on the wholesale electricity market.

Solar exports are sold and bought in the retail market

Small customers sell exports in the retail market. However, the market is not confined to solar exports alone. Changes in the level of competition in the retail electricity market are likely to affect competition in the solar export market. As a customer's decision to invest in a solar PV system has a significant impact on their electricity retailer's revenues (discussed further below), trends in the solar export market also have implications for competition in the retail electricity market.

[52] To the extent that there is competition between electricity and other forms of energy generation, the relevant market definition might be broadened.

Given these interrelationships, we have defined the 'market' to include both the solar export market and the retail electricity market.

4.2.2 The geographic market

For the geographic definition of electricity markets in Queensland, the state is typically broken up into SEQ and regional areas serviced predominantly by Ergon Energy.

Ergon Energy pricing zones are based broadly on Queensland's local government areas (LGAs) (Figure 20).

Figure 20: Ergon Energy zone coverage

East

The whole LGAs of

Bundaberg
Cairns
Cassowary Coast
Fraser Coast
Gladstone
Mackay
North Burnett
Rockhampton
South Burnett
Southern Downs
Toowoomba
Whitsunday
Townsville
Banana
Livingstone
Burdekin
Hinchinbrook
Cherbourg
Woorabinda
Yarrabah

Part of the following LGAs:

Gympie
Douglas
Isaac
Western Downs
Central Highlands
Tablelands
Mareeba

West

The whole LGAs of

Barcaldine
Blackall – Tambo
Charters Towers
Longreach
Maranoa
Balonne
Bulloo
Carpentaria
Cook
Croydon
Etheridge
Flinders
Hope Vale
McKinlay
Murweh
Paroo
Quilpie
Richmond
Winton
Wujal Wujal

Part of the following LGAs:

Barcoo
Douglas
Goondiwindi
Isaac
Western Downs
Central Highlands
Tablelands
Mareeba

Mount Isa

Consists of the regulated network within the whole LGAs of Cloncurry (S) and Mount Isa (C), and those parts of Burke (S) and Boulia (S) supplied from the Mount Isa system.

Source: Ergon Energy Corporation 2015a, p. 14.

The three pricing zones are:[53]

- East zone: those areas where the network users are supplied from the distribution system connected to the national grid and have a relatively low distribution cost to supply;
- West zone: those areas outside the east zone and connected to the national grid, which have a significantly higher distribution cost of supply than the east zone; and
- Mount Isa zone: broadly defined as those areas supplied from the isolated Mount Isa system.

[53] Ergon Energy Corporation 2015a.

The east zone accounts for roughly 90 per cent of Ergon Energy's customer base, the west zone 8 per cent, and the Mount Isa zone 2 per cent.[54]

4.3 Competition in the Queensland solar export market

There is no definitive measure or single 'test' of the level of competition in a market. Competition assessments use various analytical tools and sources of information to judge how competitive a market is and the degree to which the market is contestable to new entrants. An assessment of market power generally involves considering evidence on market scope and structure, entry conditions, the behaviour of firms and their financial performance.

Barriers to entry may include:

- structural or technological barriers such as large sunk costs (committed capital that cannot be withdrawn without significant loss);
- policies such as regulatory barriers, including licensing conditions, tariffs, foreign investment rules, explicit restrictions on the number of market participants and intellectual property rights; and
- strategic barriers such as using exclusive dealing arrangements to foreclose the market to other firms.[55]

Assessments also need to be forward-looking, as regulatory interventions influence prices and incentives for investment, entry of new suppliers, and consumer decisions.

As retail electricity market conditions are an important driver of the level of competition for solar export customers, much of the discussion below analyses competition in the retail electricity market. A full assessment of competition in the retail electricity market is provided in the QPC's Electricity Pricing Inquiry.[56]

4.3.1 Market concentration

As at 16 November 2015, there were 16 active retailers supplying residential and small business electricity customers, 11 of which had at least some solar customers.[57] For the retail electricity market in 2014–15, the market share of the largest two firms accounted for around 81 per of small customers, down from 85 per cent in 2011–12 (Figure 21). The solar export market had a higher level of concentration in 2011–12, at 91 per cent, but, as a less mature market, market concentration has decreased more rapidly, with the largest two firms accounting for 83 per cent of small solar customers in 2014–15. Herfindahl–Hirschman indices (HHI)[58] indicate high but declining levels of concentration in both markets.

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[54] QCA 2013a, p. 83.

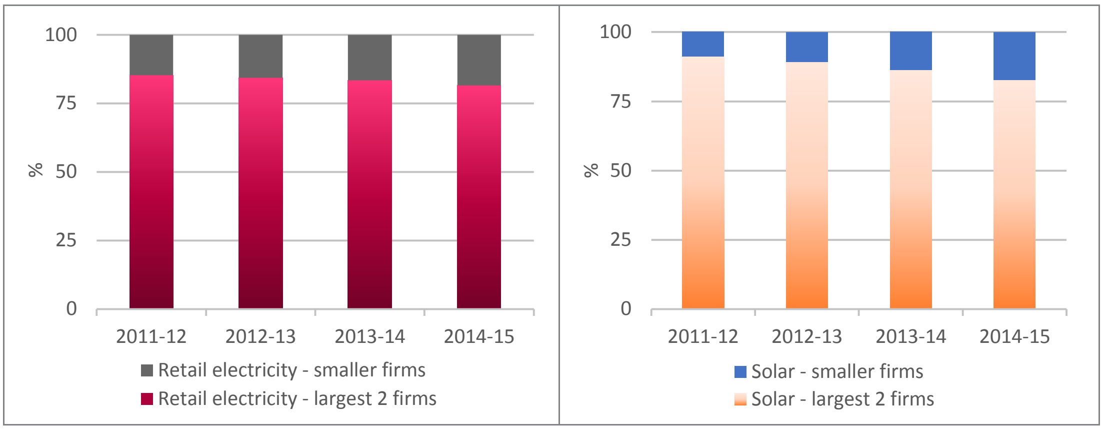
[55] ACCC 2008, p. 40.

[56] QPC 2016a.

[57] QCA 2015c, p. 35.

[58] A HHI is a measure of market concentration. The HHI is calculated by summing the squares of the market shares of each retailer, thereby giving more weight to larger retailers. The HHI ranges from 0 to 10,000. In a competitive market the HHI approaches zero, and a pure monopoly the HHI is 10,000. In 2014–15, the HHI index scores for the SEQ retail electricity market and solar export markets were 3807 and 3757, respectively; down from the corresponding index scores in 2011–12 of 4215 and 4454.

Figure 21: SEQ market shares for small customers, November 2015



Source: Energex unpublished data.

In regional Queensland, there were 74,872 solar installations (68 per cent) under the Solar Bonus Scheme (SBS) and 34,502 other solar PV installations, as at September 2015. Only a small number of installations are serviced by alternative energy sellers (AGL, QEnergy and Sanctuary Energy), with Ergon Energy (Retail) servicing all remaining customers.

4.3.2 Market contracts and customer switching

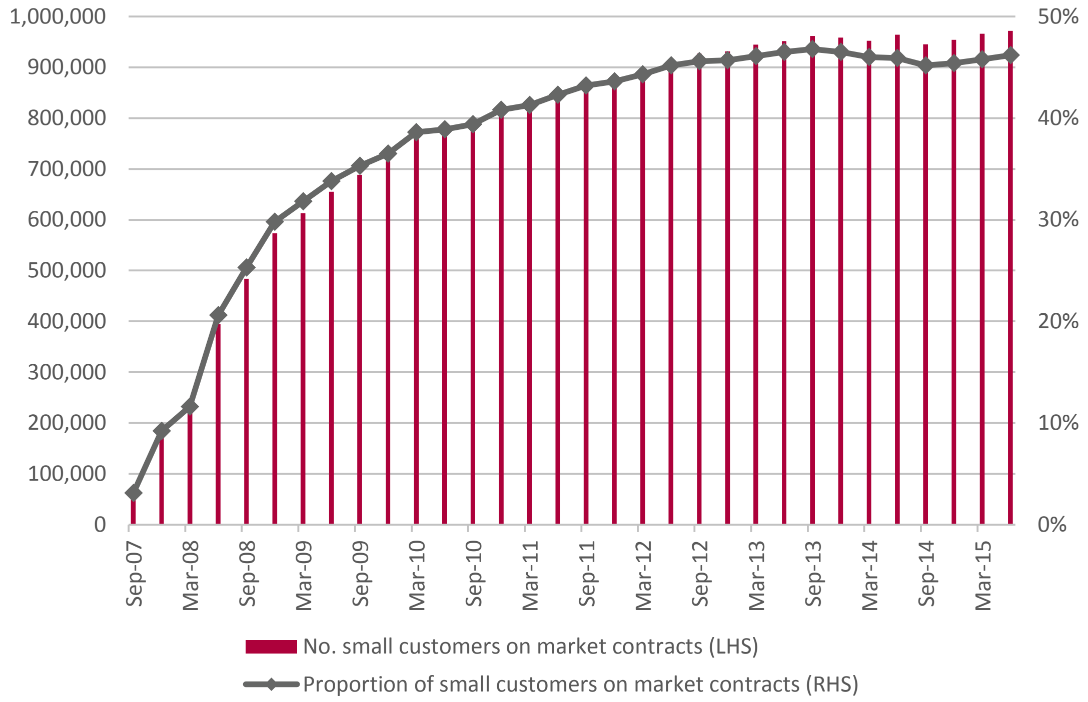
Since 2007, all Queensland customers have been able to choose their electricity retailer. Customers who have not accepted, or do not have access to, a market contract are supplied on a regulated standard contract and pay notified prices set by the QCA. Nearly all customers outside of SEQ continue to be supplied by Ergon Energy (Retail), paying notified prices.

The number of small customers who have moved to a market contract rose to 45 per cent of customers by mid-2012 in Queensland, and has stabilised at that level (Figure 22) (in SEQ only, the percentage is higher at around 70 per cent of small customers on market contracts). As at June 2015, large customers (those with consumption greater than 100 MWh per annum) are more likely to be on market contracts, with 72 per cent of large customers electing for market contracts.

The Australian Energy Market Commission (AEMC) found that 37 per cent of electricity retailer switches in SEQ in December 2014 were from Origin Energy and AGL to Energy Australia or a second tier retailer.[59] Twenty per cent of all electricity retailer switches were from a second tier retailer or Energy Australia to Origin Energy or AGL.

[59] AEMC 2015a.

Figure 22: Small customers on market contracts in Queensland



Note: Small customers are those with annual consumption of less than 100 MWh.

Source: QCA 2015e.

The rate at which customers switch between retailers provides one indicator of the level of competition in a market, but other information is often required to interpret switching rates:

> *Switching is an imperfect measure of effective competition in isolation and needs to be considered in the context of the market. For example, low switching rates can be indicative of a well-functioning market and could be the result of retailers offering customer retention incentives, less use of door-to-door marketing tactics, moderating prices, customer satisfaction with existing retailers and market maturity generally. In contrast, high rates of switching can indicate customer dissatisfaction that would not be expected in a well-functioning market.*[60]

As the market has matured following the introduction of full retail competition (FRC), the number of small customer switching retailers per month in Queensland has stabilised at around 17,000 to 21,000 customers per month (Figure 23). AEMO customer switching data includes customers switching in regional areas. However, this is a very small amount of the total number of customers switching.

[60] QCA 2015c, p. 35.

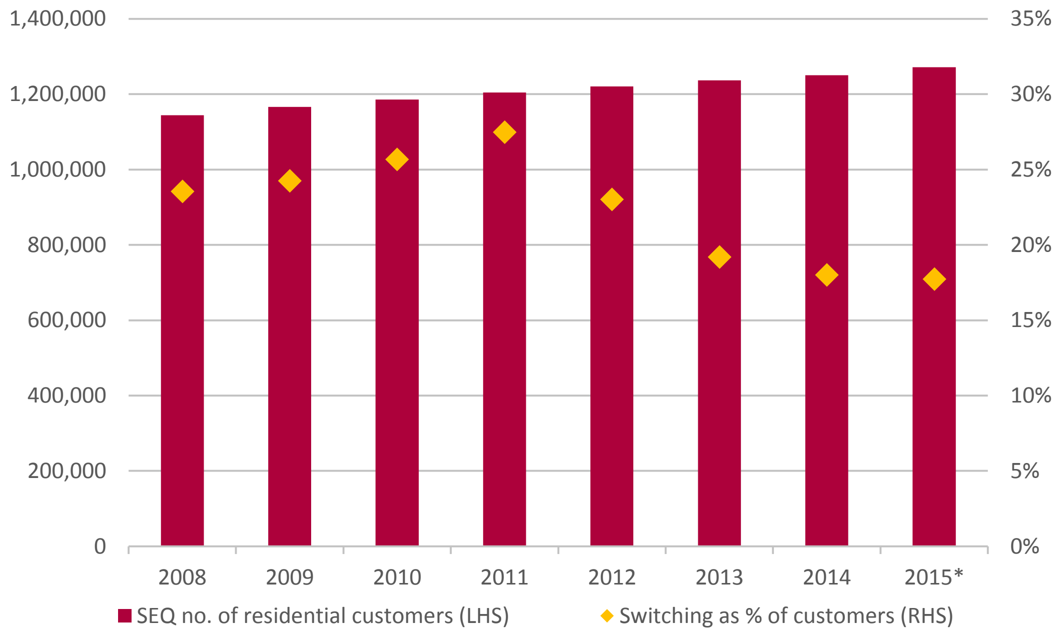
Figure 23: Monthly small customer switching since the introduction of FRC in Queensland

Source: AEMO monthly retail transfer statistics.

For 2014–15, the number of small customers switching retailers was 225,343 customers out of a total of 1,271,644 customers (or 17.7 per cent) (Figure 24).

Switching data does not capture customers who have chosen to switch plans with their existing retailer. Data provided by retailers for the AEMC's 2014 retail competition review suggested that up to 20 per cent of customers changed their electricity plan and 16 per cent of customers changed their gas plan with their existing retailer in 2013.[61]

Figure 24: SEQ annual customer switching rates



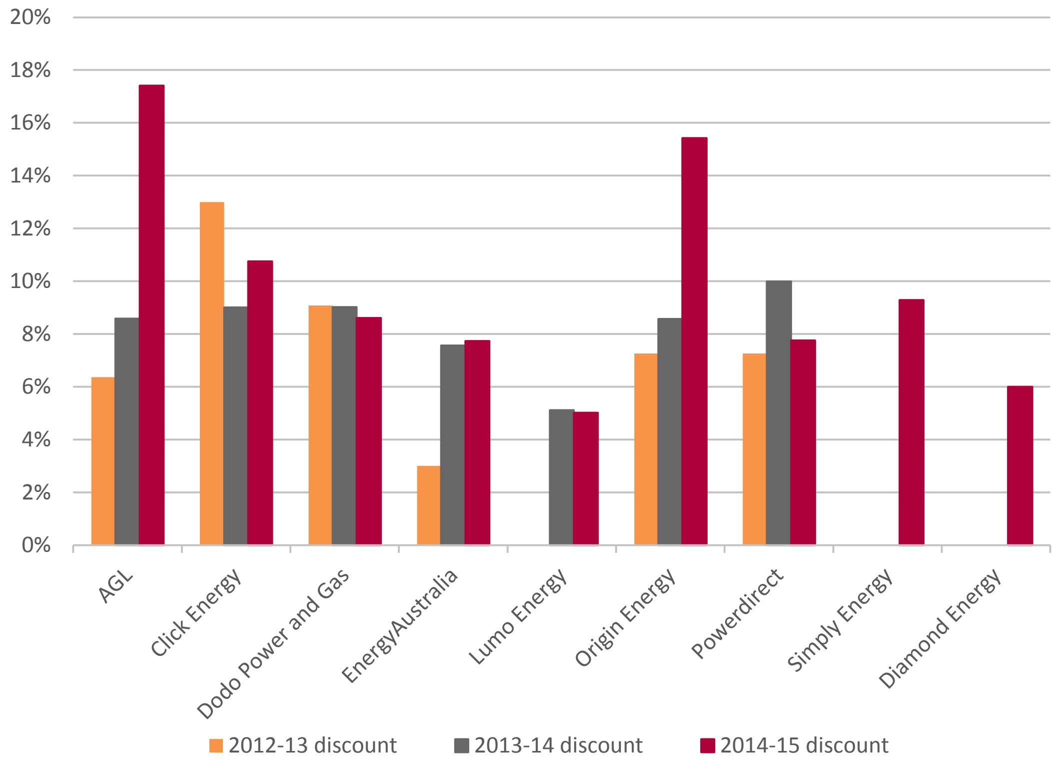
Source: AEMO monthly retail transfer statistics; Energex 2015a.

[61] AEMC 2014a, p. 54.

Customer surveys undertaken for AEMC suggest the key reason for switching retailer or plan in all NEM jurisdictions was to obtain a better price. In SEQ, 63 per cent of residential and 67 per cent of small business customers cited price-related reasons for switching electricity retailer or plan. Other drivers for switching include moving house and wanting improved customer service.[62]

As electricity retailers engage largely in price competition, the degree of discounting by retailers can provide an indication of the level of competition. The QCA found that, as at 30 April 2015, there were 61 supply offers available to residential customers, 39 of which would deliver savings to customers compared to notified prices.[63] The largest generally available effective discount was 17.4 per cent, the smallest was 5.0 per cent, and the median discount was 8.6 per cent (compared to 7.3 per cent in May 2013) (Figure 25).

Figure 25: Effective discounts offered to residential customers (percentage off total bill)



Notes: 1) Based on information from previous QCA price comparator retrieved; April 2013, May 2014 and May 2015. Discounts are relative to an annual customer bill based on consumption of 4100 kWh per year on tariff 11 prices. Excludes offers available to solar PV customers only. Origin Energy and AGL effective discounts based on inclusion of 'first month free' offer. AGL effective discount includes $50 signup credit. 2) Simply Energy commenced making offers in SEQ in 2014–15, however discounts are available to members of RACQ only. Diamond Energy did not offer discounts prior to 2014–15. In 2012–13, Lumo Energy offered Frequent Flyer points instead of discounts.

Source: QCA 2015c.

4.3.3 Market offers – feed-in tariffs

For those retailers offering feed-in tariffs, prices are in the range of 4–11c/kWh (Table 2 of Chapter 2). The variety of tariffs on offer is usually viewed as an indicator of a reasonably healthy state of competition:

[62] AEMC 2015a, p. 53.
[63] QCA 2015c, p. 36.

> *This difference between feed-in-tariffs on offer is explained by retailers, in a competitive market, seeking to attract customers through a range of products. In Queensland, where more than 20 per cent of households have a solar PV system on their rooftop, retailers that do not offer customers a satisfactory feed-in-tariff risk losing business to other retailers. Equally, a new entrant retailer may not offer a competitive feed-in-tariff because they may wish to compete for customers through other products and services (such as lower general tariff rates to customers or higher discounts). Retailers are best placed to determine which products they should offer customers in the context of a competitive and deregulated market. Customers benefit from a competitive market where retailers offer a range of products and are free to innovate to attract new customers.*[64]

We have also considered retail feed-in tariffs in the context of wholesale pool prices for Queensland. Except for one retail offer, all are higher than what a solar exporter could achieve if they could sell their electricity into the wholesale market for the time-varying price. Based on wholesale pool prices for 2015–16 and the average solar PV generation profile, a solar PV exporter would earn 5.49c/kWh (see Chapter 8).

In regional areas, Ergon Energy (Retail), AGL Energy, Sanctuary Energy and QEnergy offer the regulated minimum feed-in tariff of 6.348c/kWh (7.448c/kWh from 1 July 2016).

Feed-in tariff offers cannot be evaluated in isolation. The rate of return to solar PV investments is influenced by the costs of the system, the revenues received from exports, and lower payments to retailers as a result of the reduction in the volume of electricity imported from the grid. A higher feed-in tariff offer does not necessarily mean a better overall deal for the solar customer if it is accompanied by a relatively higher electricity tariff.

IPART analysed whether NSW electricity offers with higher feed-in tariffs were better than those with bigger discounts on usage and/or supply charges but with lower feed-in tariffs. IPART concluded:

> *We find that an electricity contract with a higher feed-in tariff does not necessarily deliver a better value to solar PV customers. For example, for an average PV customer who consumes 65% of PV generation and exports the rest, the contract from Retailer J with a six cent feed-in tariff is a better offer than that from Retailer B which offers a 10 cent feed-in tariff. In some cases, PV customers may be better off taking up contracts that do not offer any voluntary feed-in tariffs. This is because some retailers are offering contracts with a bigger discount on supply and/or usage charges, instead of offering high voluntary feed-in tariffs. This indicates that customers should consider voluntary feed-in tariffs as part of an overall electricity market offer.*[65]

An analysis of Queensland electricity offers also suggests the highest feed-in tariff does not necessarily provide the best overall deal for PV customers.

In June 2016, there were 38 unique electricity contracts offered by 12 retailers to customers (solar PV and non-solar PV) in Queensland. Of these, ten retailers provided a total of 22 electricity contracts with a feed-in tariff.[66]

Table 11 shows estimated bills for two scenarios based on retailers' electricity pricing and voluntary feed-in tariffs. In the table, the numbers in brackets show rankings from the highest to the lowest.

Based on the market offers, for an average PV customer who consumes 70 per cent of PV generation and exports the rest, a contract with a 10c/kWh feed-in tariff provides the lowest overall electricity bill. But, the highest retail market offer of 11c/kWh ranks 30th. Solar PV customers would be better off taking up one of the eight contracts with no feed-in tariff but a

[64] Origin Energy, sub. 24, p. 3.
[65] IPART 2015, p. 39.
[66] These contracts were obtained from the EnergyMadeEasy website, https://www.energymadeeasy.gov.au, using a postcode of 4000 (Brisbane) accessed 7 June 2016.

lower electricity cost. An offer with a relatively low feed-in tariff of 4c/kWh ranks third-best in regard to the annual bill due to its pricing structure.

The analysis highlights feed-in tariffs should be evaluated as part of an overall electricity market offer rather than as a sole indicator of value-for-money.

Table 11: Electricity contracts available in south east Queensland

Offer	*Feed-in tariff (c/kWh)*	*Rank*	*Consume 70%/Export 30%*		*Consume 50%/Export 50%*	
			Bill	*Rank*	*Bill*	*Rank*
1	10	2	$954	1	$1074	1
2	6	7	$981	2	$1131	2
3	4	21	$992	3	$1160	5
4	6	7	$1003	4	$1156	3
5	6	7	$1003	5	$1156	4
6	8	4	$1022	6	$1164	6
7	6	7	$1024	7	$1210	9
8	6	7	$1025	8	$1182	7
9	6	7	$1026	9	$1182	8
10	6	7	$1043	10	$1234	10
11	0	23	$1078	11	$1280	14
12	0	23	$1078	12	$1280	14
13	6	7	$1078	13	$1273	13
14	6	7	$1078	14	$1240	12
15	8	4	$1087	15	$1238	11
16	0	23	$1102	16	$1309	23
17	0	23	$1107	17	$1314	24
18	6	7	$1115	18	$1284	16
19	6	7	$1115	19	$1284	17
20	6	7	$1115	20	$1285	18
21	6	7	$1115	21	$1285	19
22	0	23	$1120	22	$1329	26
23	0	23	$1126	23	$1337	28
24	5	20	$1129	24	$1308	22
25	6.2	6	$1139	25	$1307	21
26	10	2	$1142	26	$1289	20
27	4	21	$1143	27	$1331	27
28	0	23	$1145	28	$1358	29
29	0	23	$1155	29	$1372	30
30	11	1	$1175	30	$1323	25
31	0	23	$1197	31	$1422	31
32	0	23	$1197	32	$1422	31
33	0	23	$1198	33	$1423	33
34	0	23	$1198	34	$1423	33
35	0	23	$1198	35	$1423	33
36	0	23	$1198	36	$1423	36
37	0	23	$1231	37	$1461	37
38	0	23	$1259	38	$1494	38

Notes: Estimated bills include GST and all discounts available. Calculations are based on a 3 kW solar system producing 4599 kWh per annum with annual household consumption of 6205 kWh.[67]

Source: QPC calculations; EnergyMadeEasy website, https://www.energymadeeasy.gov.au.

4.3.4 The retail electricity market and solar exports are financially linked

The link between retail electricity sales and solar exports means that the state of competition in the retail electricity market will influence the feed-in tariff offers made by retailers. Some retailers

[67] Based on 17 kWh/day typical usage; see CEC 2015d, p. 9.

may choose to only market to non-solar customers, but this customer category increasingly forms a smaller share of households and small businesses.

Where feed-in tariffs are based on market offers, a retailer's feed-in tariff will take account of a number of factors, including:

- the loss in retail electricity market share and revenues that may result if it sets a feed-in tariff too low;
  - this involves predicting the strategies of other retailers and customer switching responses to feed-in tariff prices, considered in conjunction with what the retailer offers in terms of retail prices, as this affects the benefit to solar investment through avoiding retail charges;
- the additional administrative costs incurred in catering for solar exports;
- any differences in the cost of sourcing energy from small-scale generators paid a feed-in tariff versus the wholesale energy market; and
- the risks involved in offering annually averaged feed-in tariffs based on forecasts — when the cost of energy sourced from the wholesale market varies constantly and sometimes significantly — and the costs of managing those risks.

The lower the feed-in tariff offered, the higher the number of households that will be incentivised to use their generation for their own consumption. Under a net metering arrangement, whenever the feed-in tariff is below the retail tariff price, solar customers will obtain more value from their solar generation by altering their consumption so that their solar export rate is as low as possible (preferably zero). If a feed-in tariff is greater than the retail tariff price, then the incentives are reversed and households benefit most from exporting as much electricity as possible.

In this way, retailers are in a form of competition with a household's internal choices between consumption and the export of energy generated from their solar system, which constrains a retailer's ability to exercise any market power it possesses. A household's substitution choices are constrained by the degree to which they can alter or shift their consumption patterns to maximise the benefit of their solar PV system.

Retailer loss in revenue from the loss of a solar export customer

Investment in solar PV systems provides a substitute to electricity imported from the grid, although — except in situations of disconnection — households continue to import a proportion of their energy needs. The substitutability of own-generated energy for energy imported has significant financial implications for electricity retailers (and also other businesses further up the supply chain).

The current regulatory framework does not prohibit a household from having one authorised retailer for solar exports and a different authorised retailer for the purchase of electricity from the grid if the household installs a second connection to the premises. For most households, the cost of installing the second connection means that the regulatory framework essentially 'bundles' the retail electricity service with the solar export service.

Each retailer in effect offers a service which delivers electricity to a household or small business. The retailer has a choice of whether to offer an additional 'export' service, where the retailer accepts the energy exports from a customer. The decision not to offer an export service means that the retailer may forego the opportunity to sell electricity to solar customers.

A retailer pays someone for the energy which it then delivers to its customers. A retailer can buy energy from the wholesale market, or it can buy energy from customers who export it into the grid. Solar exports substitute for energy that would have been purchased from the wholesale market.

If a feed-in tariff is based on a retailer's avoided costs of electricity supply, then, over the course of a year, retailers are indifferent as to whether electricity is sourced from the NEM or from solar PV owners. The money paid for solar energy is equal to the money the retailer would have had to pay to the NEM for wholesale energy, taking account of the line losses of transporting energy. Therefore, a retailer would be indifferent to a solar customer remaining with the retailer or switching to an alternative retailer, if the focus is solely on a retailer's cost of sourcing energy to be on-sold.

In the case of a regulated feed-in tariff, if the tariff was set above prices in the wholesale electricity market (taking account of line losses), then a retailer would prefer to lose the customer who is a relatively expensive source of energy supply.

However, losing a solar export 'customer' as a source of electricity supply also results in a loss of electricity sales to the customer (albeit, a lower volume of sales than if the household or small business did not have a solar PV system). Retailers make their money from selling electricity, so while the retailer may be indifferent to losing solar exports as a source of energy, the retailer is not indifferent to the loss of retail electricity sales.

For a typical low-consumption household with a 3.0 kW PV system, the annual loss in revenue is roughly $375 (Table 12). For a high-consumption household with the same PV system, the annual loss in revenue amounts to roughly $1042. For a given level of annual consumption, a smaller PV system means that households import more from the grid, so that the revenue impact of the loss of customers with small PV systems is greater than for large PV systems.

These calculations assume that a retailer is offering a feed-in tariff based on avoided costs that equal over a year, on average, what the retailer would have to pay for energy in the wholesale market taking account of line losses. Therefore, with the loss of a solar customer, a retailer's cost for sourcing energy to be on-sold is unchanged (what the retailer saves in feed-in tariff payments for energy exported from solar PV panels then has to be spent acquiring energy from the wholesale energy market). The impact of a loss of a solar customer on pre-tax net revenue is driven solely by the impacts on gross revenues through reduced energy sales and not by changes in a retailer's per unit cost of energy supply.

Table 12: Annual revenue loss to a retailer from losing an average solar customer

	1.5 kW	*3.0 kW*	*5.0 kW*
Assumptions			
PV system generation (kWh)^	2100	4100	6900
Average wholesale energy price (c/kWh)	5.3	5.3	5.3
Line losses (c/kWh)	0.7	0.7	0.7
Feed-in tariff (c/kWh)	6.0	6.0	6.0
Tariff 11 variable charge (c/kWh)	22.238	22.238	22.238
Tariff 11 fixed charge (retailer component) (c/day)*	57.328	57.328	57.328
Scenario A: Low-consumption household			
Annual consumption (kWh)	3000	3000	3000
Export rate (%)	35%	45%	60%
Exports (kWh)	735	1845	4140
Consumption supplied by own-generation (kWh)	1365	2255	2760
Consumption supplied by imports from grid (kWh)	1635	745	240
Retailer's energy costs			
Solar households ($)	$44	$111	$248
NEM ($)	–$44	–$111	–$248
Change in retailer’s energy supply costs ($)	$0	$0	$0
Retailer's revenues			
Electricity sales from grid (kWh)	–1635	–745	–240
Revenue from electricity sales ($)	–$364	–$166	–$53
Revenue from fixed charge ($)	–$209	–$209	–$209
Impact on retailer's gross revenues ($ annual)	–$573	–$375	–$263
Impact on retailer's pre-tax net revenue ($ annual)	–$573	–$375	–$263
Scenario B: High-consumption household			
Annual consumption (kWh)	6000	6000	6000
Export rate (%)	35%	45%	60%
Exports (kWh)	735	1845	4140
Consumption supplied by own-generation (kWh)	1365	2255	2760
Consumption supplied by imports from grid (kWh)	4635	3745	3240
Retailer's energy costs			
Solar households ($)	–$44	–$111	–$248
NEM ($)	$44	$111	$248
Change in retailer’s energy supply costs ($)	$0	$0	$0
Retailer's revenues			
Electricity sales from grid (kWh)	4635	3745	3240
Revenue from electricity sales ($)	–$1031	–$833	–$721
Revenue from fixed charge ($)	–$209	–$209	–$209
Impact on retailer's gross revenues ($ annual)	–$1240	–$1042	–$930
Impact on retailer's pre-tax net revenue ($ annual)	–$1240	–$1042	–$930

*Notes: *The tariff 11 fixed charge for 2015–16 is 106.728c/day. 49.400c goes towards network services, leaving a contribution to retail fixed costs of 57.328c. ^System generation for solar zone 3 (the majority of Queensland).*
Source: QPC calculations.

The ability to substitute between alternative retailers of electricity gives both non-solar and solar customers a degree of bargaining power. The link between solar exports and imports of electricity from the grid is likely one reason why some retailers are willing to pay customers more for their exported energy than what they could obtain the energy for from the wholesale market.

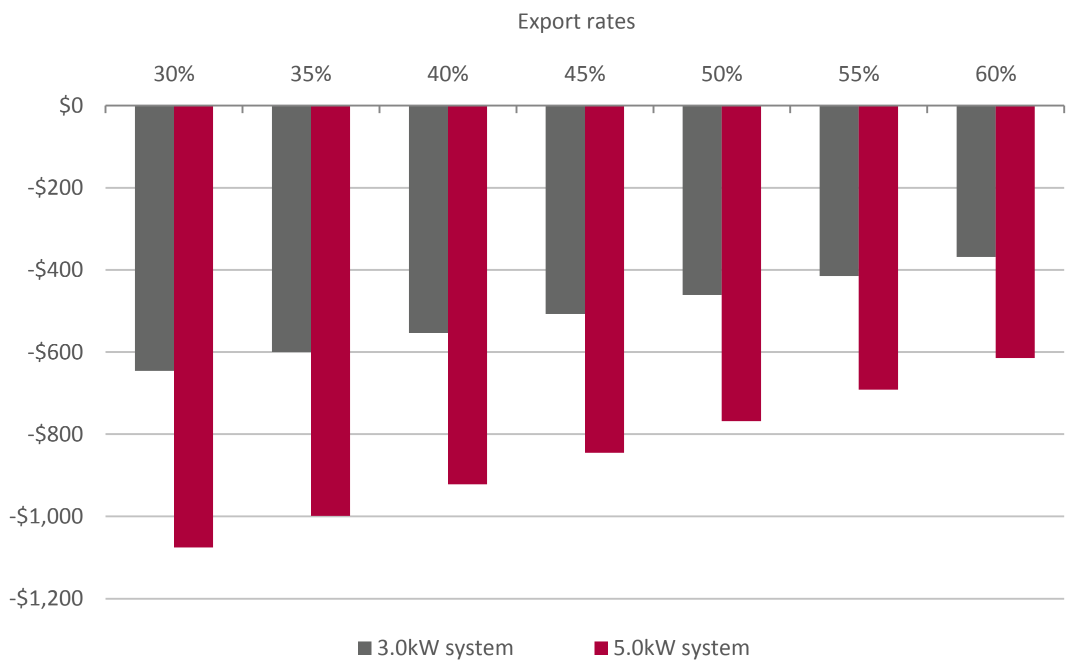
Given the increasing penetration rate of solar PV systems, a retailer that does not offer a satisfactory feed-in tariff will find it more difficult to maintain or grow market share in the retail electricity market, since solar customers will make up a larger share of the total market.

Reduced retailer revenue when a customer invests in solar

Even if a retailer retains a customer who invests in solar, there is a reduction in a retailer's revenue.

Electricity generated by a customer's solar PV system is either used by the customer or exported. The more the customer uses, the lower the export rate, and the higher the loss in revenues to the retailer, as customers require less electricity to be imported from the grid. In 2015–16, for a 5.0 kW system and at an export rate of 40 per cent, the retailer stands to lose $922 (Figure 26). If there were no changes in the variable component of tariff 11 at 22.238c/kWh, then the retailer, over a 20-year timeframe, stands to lose $10,575 (in NPV terms, discounted at six per cent).

Figure 26: Retailer's loss in revenue when a customer invests in solar



Notes: Based on a tariff 11 variable component in 2015–16 of 22.238c/kWh.
Source: QPC calculations.

4.3.5 Market entry and new services

The market for energy services includes a wide and growing range of services offered by brokers, buying groups, price comparator websites, aggregators and alternative energy sellers. The new business models can add value and gain market share where they help customers overcome budget constraints and various information problems — leading to additional uptake of solar PV systems.

Traditionally, retailers have also responded to this increase in competition by introducing new products of their own:

> *The solar PV market has become a mainstream product with the three leading retailers in the NEM offering solar products in addition to electricity and gas supply. The energy market is evolving and new products and offers are being developed to facilitate the adoption of solar energy. For instance, solar PV installation typically requires a large capital outlay which could be a barrier to entry for customers. However, new solar products and financial arrangements are being introduced into the Australian market to address this barrier, including innovative offers with no upfront payments... There are consumers who have difficulty accessing solar power such as those who live in apartments or those who rent. Over time, new offerings are likely to emerge tailored to these customer segments such 'community solar'.*[68]

The market for Solar Power Purchase Agreements (SPPAs) is the most active area at present (Box 11). The effect of SPPAs on competition can be seen in the response of traditional electricity retailers who are developing and marketing their own SPPA products to serve customers better and thwart loss of market share. However, these developments are 'new', with many of the products being introduced only in 2015. Impacts on the retail electricity market and solar export market are mostly 'in the future' and difficult to predict.

A combination of policy reforms and technological change has meant that market power has been reduced over time in those elements of the supply chain where competition has been introduced. This trend may continue with distributed generation technologies achieving greater penetration levels.

Box 11: New services from traditional retailers introduced in 2015

In early 2015, AGL Energy launched its 'Solar Smart Plan' which is a SPPA targeted at residential and commercial customers. Customers pay $0 up-front, sign a 7- or 12-year contract, and pay AGL for energy usage at a rate below current retail electricity prices. Installation of the system can include battery storage. The new product is in response to competitive retail market pressures from the emergence of rival leasing and SPPA offerings and energy service companies. At the end of the contract period, the customer has the option to take ownership of the solar system. SPPA will also be marketed to customers who choose to continue to have their grid supply provided by a different retailer.

Origin Energy has launched 'Solar as a Service' where the company owns, operates, maintains and guarantees performance of a PV system over its life. Customers buy the solar energy generated from the solar system at a lower rate than retail electricity tariffs for an agreed period at an agreed price. The service is available to residential and business customers within a 100 km radius of the central business districts of Brisbane and the Gold Coast, and within 50 km radius of Townsville. Contract periods are for 7, 10 or 15 years, at the end of which customers have the option of extending the agreement or offering to buy the installed system. Origin's move into PPAs is being subsidised by the Clean Energy Finance Corporation (CEFC) which announced a 12-year $100 million financing commitment on 1 July 2015. The CEFC stated that the finance will help support Origin's offering of SPPAs to business and residential customers, helping more consumers' access solar energy.

On 6 August 2015, Ergon Energy (Retail) announced its 'Hybrid Energy Service' regional trial. The 12-month trial is being conducted in 33 homes across Townsville, Cannonvale and Toowoomba with larger household energy users targeted (e.g. 4+ bedroom family homes). A 4.9 kW SunPower PV array and a 12 kWh/5 kW Sunverge battery storage and control system are installed at each trial site. The equipment is owned and maintained by Ergon Energy (Retail). Customers sign up for a one-year trial with the possibility of extension. The Hybrid Energy Service trial will assess how Ergon Energy (Retail) can best deliver a reliable, cost-effective option to customers in the future. The trial is a precursor to a planned product rollout where customers pay no up-front cost for the system, enter into a 10-year contract, and pay a monthly fee, while the company owns, installs and maintains the system, and manages load curtailment with customer consent. The project is being supported by the Australian Renewable Energy Agency (ARENA), which has contributed $400,000 towards Ergon Energy's approach to provide solar PV and battery storage systems to residential customers.

Source: CEFC 2015; REneweconomy 2015; Ergon Energy Queensland 2015e.

[68] AGL, sub. 19, p. 5.

4.3.6 Policies that limit competition

For firms to exercise substantial market power and depress prices below competitive levels for a sustained period, barriers to entry must be high enough to prevent or discourage new firms from entering the market. While various policy and regulatory reforms over the last decade have supported competition, others continue to impede the development of a competitive electricity supply industry.

For the AEMC's 2015 retail competition review, a survey of retailers was undertaken collecting information on a range of issues. Retailers expressed conflicting views about the impediments to entry and expansion:

- Larger established retailers stated that there are no impediments.
- Smaller retailers in the retail electricity market identified a number of impediments, including: the continued application of retail price regulation in Queensland and the way in which it is applied; and uncertainties associated with the introduction of the National Energy Customer Framework (NECF), and policy positions on the merger of generators and potential changes to feed-in tariff schemes.[69]

UTP and regional competition

The government's Uniform Tariff Policy (UTP) ensures that Queensland non-market electricity customers of a similar type pay the same price for electricity, regardless of where they live.

Notified prices paid by non-market customers do not reflect the full cost of electricity supply for most regional and remote customers. A subsidy (Community Service Obligation (CSO)) is provided by the Queensland Government to Ergon Energy (Retail) (and to a limited extent Origin Energy). The CSO covers the difference between the costs of supply allowed for in the notified prices and actual costs of supplying regional areas ($596 million in 2014–15).[70]

Ergon Energy (Retail) and Origin Energy (for the Goondiwindi area) are the only retailers that receive a subsidy to supply regional customers, creating a barrier to the development of retail competition in regional Queensland, including for solar exports. As a result, Ergon Energy (Retail) and Origin Energy's retail business is not exposed to the same pressures to lower costs and improve efficiency as businesses operating in a fully competitive market.

The lack of effective retail competition in regional areas, and the role of the UTP in achieving that outcome, are acknowledged by electricity retailers as providing a rationale for some form of continued regulation in regional areas:

> *[F]eed-in-tariffs are regulated in Ergon Energy's distribution network in regional Queensland. There is presently limited retailer presence in this region due to the Uniform Tariff Policy. These underlying policy issues will need to be addressed if there is to be a competitive retailer market for all energy services in regional Queensland. In the absence of these reforms taking place, and effective competition developing, Origin accepts the need for a regulated feed-in-tariff in regional Queensland.*[71]
>
> *… the lack of effective competition in regional Queensland and the role of Ergon Energy as the sole electricity retailer remains an issue. This situation has been the result of government policy, the Uniform Tariff Policy, which sets electricity retail prices at levels which are unprofitable for new entrants while providing the incumbent retailer, Ergon Energy, with a Community Service Obligation payment which compensates for the revenue shortfall. As such, until competition in the retail*

[69] AEMC 2015a, p. 67.
[70] See QPC 2016a, chapter 9, p. 221.
[71] Origin Energy, sub. 24, p. 3.

> *electricity market is allowed and incentivised to develop, we believe it is appropriate for the QCA to set the solar feed-in tariff in regional Queensland.*[72]

4.3.7 Summary of the present state of competition

Although market concentration in the SEQ retail electricity market for small customers is high, a range of indicators suggest that there is a reasonable level of competition which is providing choice and price benefits to consumers.

This is consistent with reviews of retail competition by the QPC, QCA and AEMC[73], which found that retail competition was reasonably effective. Their findings indicated that smaller retailers are growing their market share, price discounting remains strong, and product differentiation is emerging.

Outside SEQ, the level of competition remains very low, with Ergon Energy (Retail) serving the vast majority of regional customers; penetration by new services and alternative energy sellers has been low to date. That said, regional retailers still face a number of disciplines that may ameliorate market power.

4.4 Exercise of market power: some considerations

4.4.1 Pre- and post-solar investment bargaining power

In competitive markets, consumers have the ability to deny a business revenue because consumers can substitute between suppliers.

In SEQ, households and businesses can substitute between electricity retailers; furthermore, they have a range of options for the installation of solar PV systems, from outright purchasing of systems through to solar leasing and SPPAs. Retailers are not only in competition with one another, but they are in a sense — given the impacts on their revenues — in competition with their own customers as 'generators'.

In regional areas, households have some bargaining power prior to investing in solar because of the impacts of their decisions on retailer revenues. Ergon Energy (Retail) is also constrained in its ability to exercise market power through retail tariffs (in part due to price regulation).

Customer decisions to invest in solar impact on a retailer through loss of revenues more than any financial impact the retailer can have on the customer.

There is no feed-in tariff strategy which could be adopted post-investment which would recoup anywhere near the amount of money the retailer stands to lose if the customer invests in solar, not even a feed-in tariff of zero. The threat of solar investment puts bargaining power in the customer's hands, not the retailer’s. In an unregulated market, that power would lead to better supply terms for the customer in order to defer investment.

However, once the decision is taken to invest in solar, the customer loses that power. A voluntary (or unregulated) feed-in tariff could be adjusted downwards ex post in order to extract greater revenues from the customer, even if those revenues are a fraction of the lost revenues that result from solar investment.

To address this risk, customers would ideally prefer to enter into a contract with their retailer which fully specifies future feed-in tariff levels and, therefore, the revenue streams underpinning the

[72] AGL, sub. 19, p. 2.
[73] QPC 2016a; QCA 2015c; AEMC 2015a.

decision to invest in solar. However, the retailer presumably seeks to avoid investment, except in those localised situations where the loss of revenues from solar investment is less than the increase in network costs that solar may help avoid. In lieu of fully specified contracts, some form of regulation may place minimum bounds on the feed-in tariff and reduce the risk of post-investment exploitation, thereby improving fairness.

4.4.2 What are the potential impacts of an exercise of market power?

A competition assessment must first determine whether incumbent firms have the ability to exert excessive market power and then identify the potential impacts of any exercise of that market power. The larger the adverse impacts, the more likely is the benefit of government intervention.

In the absence of regulation, a reduced feed-in tariff might impede the overall level of investment in solar, thereby reducing the size of the market and the potential financial returns to market entry. The pricing strategy could deny the benefits of competition to regional customers. However, such a strategy by the retailer might be counter-productive longer-term, because: customers will respond to such pricing practices by switching providers when alternative options become available; and it makes it more likely that market entry will occur as there is a ready-made customer base who are disenfranchised from the incumbent supplier.

Impact of feed-in tariffs on incentives to invest

To examine the impact of the feed-in tariff on investment in solar PV, the payback period was calculated with and without feed-in tariffs. Estimated payback periods are presented for two discount rates (zero and six per cent) under three scenarios:

(1) a lower bound scenario which includes high export rates and a system useful life of 20 years;

(2) a base case or benchmark scenario which includes average observed export rates and a useful life of 20 years; and

(3) an upper bound scenario involving low export rates and a system useful life of 25 years.

Under each scenario, the payback was first calculated based on a feed-in tariff set to avoided cost, and then with no feed-in tariff over the useful life of the system. In this way, the only source of financial benefit to investors is the savings from reduced imports from the grid. This is a hypothetical exercise or 'what-if' scenario modelled to assist understanding of the relationship between feed-in tariffs and investment in solar.

The export rates used in the tests are presented in Table 13.

Table 13: Export rates

	1.5 kW system	*3.0 kW system*	*5.0 kW system*
Lower bound scenario	25%	35%	45%
Base case	35%	45%	55%
Upper bound scenario	45%	55%	65%

Source: QPC assumptions based on ACIL Allen 2014; Energex and Ergon Energy unpublished data.

The results show that, even in the absence of a feed-in tariff, under many circumstances the financial return to investment in solar is sufficient for the investment to break even within the useful life of the panels, given the presence of the SRES subsidy. Table 14 compares returns with and without feed-in tariffs under the three scenarios.

Table 14: Impact of feed-in tariffs on financial returns — investment in solar zone 3 in 2015–16

	Scenario: lower bound			*Scenario: base case*			*Scenario: upper bound*		
	IRR (%)	*0% (yrs)*	*6% (yrs)*	*IRR (%)*	*0% (yrs)*	*6% (yrs)*	*IRR (%)*	*0% (yrs)*	*6% (yrs)*
Feed-in tariff = Avoided cost									
1.5 kW	6.6%	11	18	7.6%	10	16	9.7%	10	14
3.0 kW	11.8%	8	11	13.3%	7	10	15.5%	7	8
5.0 kW	12.7%	8	10	14.4%	7	9	16.8%	6	8
Feed-in tariff = 0 cents									
1.5 kW	2.0%	16	nbe	4.2%	13	nbe	7.5%	11	19
3.0 kW	4.5%	13	nbe	7.5%	10	16	11.3%	8	12
5.0 kW	2.8%	15	nbe	6.4%	11	19	10.7%	9	13

Note: 'nbe' stands for 'no break even'. Financial calculations based on a system installed in solar zone 3. Some key assumptions relate to gross and net installed system prices (system installation costs can vary significantly for systems with the same rated outputs), the output of the system in kWh (many factors can influence realised system output), projected wholesale energy prices (as wholesale energy costs drives the feed-in tariff under an avoided cost methodology, although market rates can differ), the variable component of projected retail import tariffs, and the rate of export and the ability of households to shift consumption to generating hours. All three scenarios include network tariff re-balancing which reduces the financial returns to solar investment.

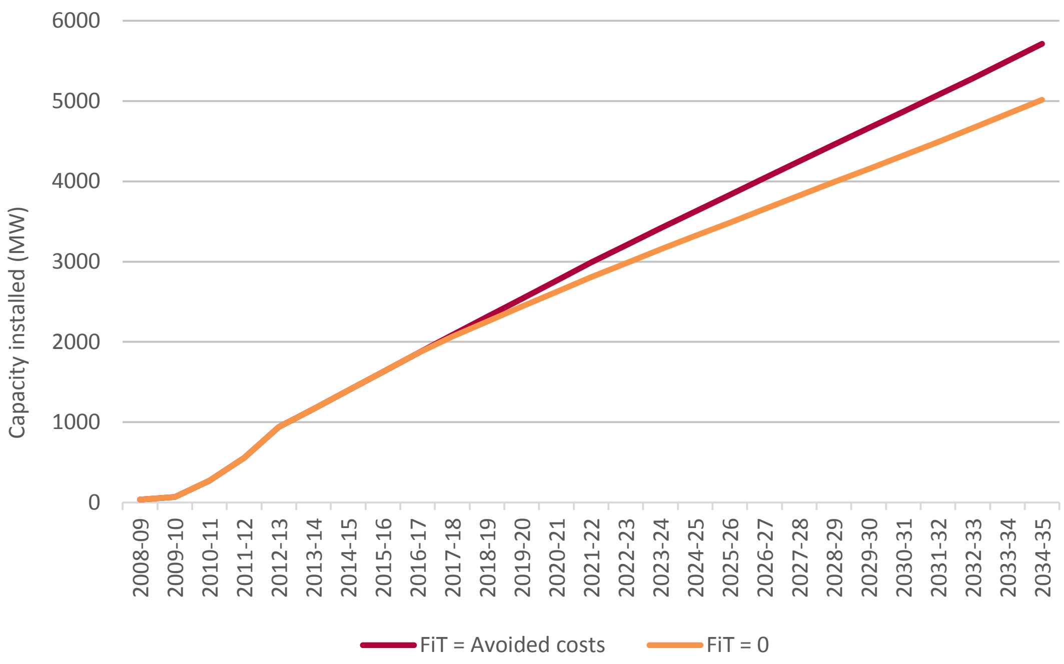
Source: QPC calculations.

The payback periods for the base case scenario, where the feed-in tariff is set based on the avoided cost methodology, are similar to those calculated by the Energy Supply Association of Australia (ESAA) for installations in Brisbane. For system sizes ranging from 1.5 kW to 5.0 kW, ESAA calculated payback periods of between seven and 10 years.[74]

The absence of a feed-in tariff does not produce a significant investment response in rooftop PV generating capacity compared to the base case where a feed-in tariff is set based on the avoided costs method (Figure 27). Rooftop PV generation capacity is reduced by 8.4 per cent and 12.4 per cent, by 2024–25 and 2034–35 respectively.

[74] ESAA 2015.

Figure 27: Projected investment under a feed-in tariff equal to avoided costs and zero



Notes: Calculations based on all base case assumptions other than the level of the feed-in tariff is changed from the avoided costs methodology to being to zero.

Source: ACIL Allen 2015; QPC calculations.

Part of the reason for the muted investment response is that solar investment is estimated to have a fairly low responsiveness to changes in system prices. In the early stages of solar PV adoption, investors were likely motivated as much by interests in a 'new' technology and environmental objectives, as by financial returns (although the strength of the investment response under the SBS suggests that the financial return was an important factor for many investors). As technologies continue to mature and penetration levels increase, a larger proportion of investors will probably be more attuned to the financial returns of the investment.

While a reduction in the feed-in tariff may not have a large impact on investment in solar, it will impact on the incomes to solar customers and raise fairness issues. Therefore, it is important to consider the likelihood of an exploitative pricing strategy actually being pursued by regional retailers.

Forward-looking market strategy

Given that the installation of a solar PV system reduces electricity imports from the grid and payments to a retailer for that energy, there is a 'broad-brush'[75] incentive to discourage the uptake of solar. However, the loss in revenues and the incentive it provides has to be weighed against resulting losses in revenue if customers switch to another retailer, or, for new installations, if the lower feed-in tariff further incentivises and supports market entry of alternative energy sellers. Ergon Energy (Retail) may adopt a strategy of maintaining the level of the feed-in tariff roughly where it currently is, perhaps varying it somewhat by region depending on differences in cost factors, as a competitive strategy to protect future revenues.

[75] Ergon Energy will still have incentives to support solar uptake where there are localised network savings that outweigh losses in revenue from reduced retail electricity sales.

Alternatively, the retailer might adopt a pricing strategy of raising the feed-in tariff above the avoided cost of supply even though this would mean that its cost of sourcing energy would be increased (given that it could buy the energy more cheaply from the wholesale market, taking account of line losses), as a strategy to discourage customers from switching. For new installations, the incentive might be bundled within a product/service, such as, Ergon Energy (Retail)'s Hybrid Energy Service. These strategies would be adopted in order to tie consumers to the regional retailer, thereby protecting future revenues (reducing the losses that may occur under future increased competition).

Concerns about, in particular, Ergon Energy (Retail) being able to offer a lower feed-in tariff post-investment if there was deregulation of feed-in tariffs, thereby unfairly altering the financial returns to investment, are valid in the sense that the immediate impacts on Ergon Energy (Retail) would be an increase in revenue without a corresponding increase in the risk of losing revenues through a loss of market share. However, while this is true in the short term, the potential exists for new entrants and increasing competition to emerge, particularly around urban centres in Ergon Energy's east zone. Reducing the feed-in tariff would raise the ire of a large customer base, and invite further entry of both traditional retailers and alternative energy sellers, even if the effects took some time.

What would be perceived as an unfair pricing policy would also have the effect of increasing the financial incentive to invest in batteries. A low or zero feed-in tariff increases the gap between the revenues that can be earned through exporting electricity and the monies that can be saved by reducing imports from the grid. Batteries enable a solar PV owner to utilise more of the electricity they generate for their own consumption, minimising the amount of revenue paid to retailers and maximising the financial benefit they receive from their solar panels.

4.4.3 Going 'off-grid' as a balance to market power

As battery storage becomes a more realistic financial option, storage solutions and services can be expected to be an important part of the new services offered to customers, including by traditional retailers.

The uptake of batteries has the potential to support greater competition through two main effects:

- Batteries increase the ability of solar customers to further reduce consumption from the grid — they strengthen the ability of customers to substitute one source of energy for another.
- Batteries expand the potential for value-adding services from alternative energy suppliers and others.

The uptake of batteries is likely to result in further reductions in demand for electricity from the grid. Customers are presently constrained in how much they can shift consumption patterns. Batteries make it possible to store generated energy and then use that energy to meet consumption demands when their solar system is not generating (at night or when there is daytime cloud cover).

ACIL Allen’s modelling for this inquiry suggests that battery uptake will be 41.8 MWh by 2020, with battery prices not at levels to make widespread deployment financially attractive. Assuming battery prices will decline by five per cent per annum, and the number of cycles a battery can achieve will improve, the uptake of batteries may increase to almost 900 MWh by 2034–35.[76] The impact of batteries on consumption behaviour, electricity imports from the grid and exports to the

[76] The uptake of batteries is discussed further in QPC 2016a, Chapter 2.

grid indicates that their impact on the industry and consumers may be more significant than their modelled megawatt hour uptake suggests.

In 2015–16, where an investor makes the decision to invest in battery storage based on financial returns criteria, batteries are still 'out of the money'.[77] The financial returns to battery storage depends a great deal on the daily load profile of a household and the ability of the storage system to reduce exports to the grid so that the household can benefit to the maximum extent possible through cost savings from reduced imports from the grid.

There are many different storage investment scenarios. For the scenarios below, it was assumed that the storage system is purchased at the same time as the solar PV system. The PV panels are assumed to have a useful life of 20 years and the batteries 10 years, thereby requiring re-investment in batteries after 10 years (although at a lower cost due to the projected declines in the cost of battery storage).

For a 5.0 kW solar PV system purchased in 2015–16, the base case without storage produces an internal rate of return of 14.4 per cent and breaks even in roughly seven years (undiscounted) (Table 15). Adding 5.0 kW of storage at the time of investment, but assuming no change in the rate of export, reduces the internal rate of return to 0.6 per cent. Achieving a 40 per cent reduction in the rate of export increases the internal rate of return to 2.5 per cent, with a breakeven of 16 years (undiscounted). With a six per cent discount rate, the investment does not break even within the assumed useful life of the system.

Table 15: Impact of battery storage on financial returns to a solar PV system investment

	System purchased in 2015–16			*System purchased in 2020–21*		
	IRR (%)	*d.r. = 0%*	*d.r.=6%*	*IRR (%)*	*d.r. = 0%*	*d.r.=6%*
3.0 kW system + 3.0 kW battery storage						
Base case w/o storage	13.3%	7 yrs	10 yrs	12.0%	8 yrs	11 yrs
With storage	0.7%	18 yrs	nbe	4.9%	13 yrs	nbe
Export rate reduced by 40%	2.2%	16 yrs	nbe	6.0%	12 yrs	19 yrs
5.0 kW system + 5.0 kW battery storage						
Base case w/o storage	14.4%	7 yrs	9 yrs	13.2%	8 yrs	10 yrs
With storage	0.6%	19 yrs	nbe	4.0%	14 yrs	nbe
Export rate reduced by 40%	2.5%	16 yrs	nbe	5.6%	13 yrs	nbe

Notes: 'nbe' signifies 'no breakeven'. 'd.r.' denotes discount rate used in breakeven calculations. Calculations assume batteries are purchased at the time of installation of the system. Calculations assume all base case assumptions, including tariff re-balancing, and that the useful life of batteries is 10 years. This means that re-investment in batteries is required after 10 years for a solar system of 20 years.

Source: QPC calculations.

The cost of storage systems are projected to decline quite strongly. The same 5.0 kW solar PV system purchased in 2020–21 is projected to result in an internal rate of return of 5.6 per cent if a substantial reduction in the export rate is achieved with a payback period of roughly 13 years. However, with a six per cent discount rate the investment still does not break even.

[77] Oakley Greenwood 2014 and Wood, Blower & Chisholm 2015 examined the financial returns to investors in storage systems that would allow households to be fully or largely independent from the grid. These studies found that current costs are prohibitive.

On current prices, battery storage is not an effective counterbalance to supplier market power. The rate at which this will change is still unknown.

4.5 Customer protections

A large number of policies and regulations are in place that seek to ensure the fair treatment of retail customers by electricity providers. The policies and regulations provide a framework to reduce problems between customers and retailers before they occur, and mechanisms to rectify problems that have occurred.

Customer protection is best provided by customers having:

- the knowledge, ability and information they need to understand the particulars of a transaction (that is, to know what they are getting); and
- the power to take their business elsewhere. Competition enhances consumer power because it makes it easier for customers to switch providers, giving their 'hard earned' to a supplier offering a better deal.

An extensive regulatory framework of consumer protection law, programs, and electricity industry-specific consumer protections exists, including through:

- *the Clean Energy Council* — installer accreditation, retailer code of conduct, and approved product listings;
- *the Clean Energy Regulator (CER)* — overall responsibility for managing the RET including the SRES which subsidises the cost of solar PV systems. The CER ensures that the SRES subsidy is provided only where systems have been installed by accredited installer and with valid products;
- *state-based electrical bodies* — overall responsibility for electrical licences, electrical safety, and electrical product compliance in each state;
- *state-based consumer protection bodies* — oversight of consumer complaints in relation to Australian Consumer Law, including product recall (in collaboration with relevant state authorities); and
- *Standards Australia* — oversight of the development and implementation of Australian Standards related to solar PV systems. Every installation carried out by an accredited installer is required to meet Australian standards.[78]

With retail electricity price deregulation commencing in SEQ on 1 July 2016, the Queensland Government has announced a market monitoring framework. Under the legislation, the Energy Minister will be able to direct the QCA to publish an annual market comparison report, with a particular focus on price movements, discounts and market trends. Market monitoring will assess whether competition remains effective and is delivering benefits for consumers.

Customers purchasing energy from authorised retailers are provided uniform protections under the National Electricity Retail Law. Customers purchasing energy from alternative energy sellers also have rights under the AER’s Exempt Selling Guideline, and these are consistent with protections under the Retail Law wherever feasible.

[78] CEC 2015a, 2015b.

Customers also have access to broad protections under general consumer protection regulatory frameworks, such as:

- the *Consumer and Competition Act 2010*, which deals with misleading, deceptive or unconscionable conduct;
- the Australian Consumer Law which deals with unfair contract terms, marketing, warranties and guarantees; and
- State and territory fair trading legislation, which provides jurisdictional agencies with a role in dispute resolution and complaints.[79]

Existing protections do not guarantee that electricity consumers' relationships with retailers will be perfect; but the protections, combined with the ability of consumers to switch retail providers and/or to install solar PV systems, will help to keep systemic market power excesses in check. Where there is consumer dissatisfaction with a retailer, consumers generally have alternatives.

4.6 Overall assessment

Electricity retailers in SEQ are under increasing competitive pressures from other retailers; therefore, they have an incentive to offer solar PV customers a fair price for solar exports.

The most significant source of competition originates from their customers’ ability to supply their own electricity in place of the electricity that would otherwise have been purchased from retailers. This pressure is intensified by alternative energy suppliers and other energy service providers being able to contest the relationship that retailers have held with their customers.

Competitive pressures in Queensland are highest in SEQ and may increase, whether through growth in the number of market participants, growth of existing smaller retailers and service providers, or simply continued price reductions and quality improvements in solar PV panels. Competition appears effective — customers are being given increased choices on how to meet their energy needs and can access feed-in tariffs from 4 to 11c/kWh. A growing number of innovative services and products have been introduced to the market.

In regional areas, Ergon Energy (Retail) is the dominant retailer, which is why both retail electricity prices and feed-in tariffs there have been regulated. There is an argument that, in the absence of regulatory price interventions, Ergon Energy (Retail) could reduce the feed-in tariff below competitive levels. These concerns underlay the rationale for regulation.

Chapter 9 examines regulatory options for solar export pricing.

Findings

4.1 In south east Queensland, multiple retailers are competing for solar PV customers, which promotes fair pricing for solar exports. As a result, there is no case to mandate feed-in tariffs to address market power.

4.2 In regional areas, Ergon Energy (Retail) possesses significant market power, which provides a basis for some form of continued regulation.

[79] AER 2013, 2014b.

5 ENVIRONMENTAL BENEFITS: AN ASSESSMENT

The terms of reference for this inquiry ask us to assess whether feed-in tariffs reflect the public and consumer benefits of solar exports. It also requires us to consider whether solar PV owners are already compensated for such benefits through existing renewable energy programs, rebates and market contracts.

This chapter outlines some principles important to the design of emission reduction policies, provides an overview of the range of existing emissions reduction policies, assesses whether solar PV system owners are already financially compensated for reducing emissions, and evaluates the cost of abatement of a subsidised feed-in tariff relative to alternative policies.

Key points

- Where solar PV reduces carbon emissions and this limits negative impacts of climate change, it produces environmental benefits that accrue to the wider community. In the absence of government intervention, these environmental benefits may not be fully taken into account by individuals and firms in their decisions on what products to buy and how best to produce them.
- The Australian, state and territory governments have many policies that seek to reduce emissions. Investors in solar PV systems receive a subsidy from the national Small-scale Renewable Energy Scheme (SRES). The SRES reduces the up-front cost of purchasing and installing a solar PV system by around 30–40 per cent on average.
- Based on average solar PV system prices, the level of the SRES subsidy is between 2.8 and 2.9c/kWh over 20 years. In terms of energy exported, households receive an additional 7.1c/kWh through the SRES. On this basis, the SRES provides at least fair compensation for emissions abatement.
- Solar PV in Queensland is projected to continue to grow strongly over the next 20 years. An additional subsidy through a feed-in tariff would increase the rate of investment, although not appreciably.
- Providing extra payments through a feed-in tariff would achieve relatively low emissions abatement at high cost:
  - More than 85 per cent of the subsidy would go towards increasing the financial returns to solar PV owners, rather than inducing additional solar PV generation.
  - Under the most likely subsidy scenario, the cost of reducing emissions is $268–327 per tonne of abatement, or $363–$422 per tonne including the SRES subsidy.
- Options are available to achieve carbon abatement at a much lower cost than can be achieved from feed-in tariffs for solar PV systems. National policy instruments are generally better suited to reducing emissions at least-cost than state and territory government policies.

5.1 Environmental benefits of reduced carbon emissions

Renewable energy is one way to reduce carbon emissions.

Solar PV can reduce demand for electricity supplied by the grid; and if this in turn reduces electricity supplied by thermal generators, carbon emissions will be lower.

The Australian, state and territory governments have introduced a range of policies aimed at reducing carbon emissions. The rationale for these policies is that if human-induced emissions increase global temperatures, and this results in harmful environmental and economic impacts, then producers and consumers may fail to take account of these external costs in their decisions.

This is described as a 'negative externality'.

Households and businesses derive benefits from electricity consumption that generates emissions (for example, by heating, air-conditioning and lighting). However, the costs of emissions (relating to human induced climate change) are imposed on the wider community.

Where this is the case, emissions may be higher than desirable because individuals and firms will take into account the costs and benefits that they directly face, but possibly not the broader costs imposed on others.

The potential costs of climate change are significant, including:

- increased water security problems in southern and eastern Australia;
- risks to coastal development from sea-level rise and coastal flooding;
- loss of biodiversity in ecologically rich sites such as the Great Barrier Reef;
- risks to major infrastructure from extreme events; and
- a decline in production from agriculture and forestry.[80]

However, designing policies to address climate change is a challenge:

- *uncertainty*: A high level of uncertainty surrounds the responsiveness of temperatures to changes in CO_2 levels from policy action. Similar uncertainties arise on the environmental and economic impacts of projected future changes in temperature;
- *transparency of costs and benefits*: Some of the costs of abatement will be visible to households and businesses early on, such as increases in electricity prices. But the impacts of emissions reduction policies on investment and the capital structure of the economy, employment, real-wage growth and longer-run economic growth will not be apparent. Benefits (insofar as policies impact temperatures) on the other hand, will not be realised until well into the future;
- *a global externality*: The targeted externality is global — all emissions contribute to atmospheric concentrations irrespective of where they occur. The benefit from national or state policies are conditional on the actions of others; and
- *policy evaluation*: The success of a policy will be hard to assess and can only be judged in the longer term — it is impossible to observe climate-related and economic outcomes with and without the policy.

[80] Intergovernmental Panel on Climate Change (IPCC) 2007.

Given these problems, policymakers need to follow rigorous policy design to ensure abatement policies effectively achieve abatement while minimising the costs to the economy and community.

Ideally, emissions reduction policies should be evaluated and selected based on their net impacts taking account of both short-run and long-run economic and environmental impacts. The policies should maximise economic efficiency — broadly defined to also include environmental impacts — for a given abatement objective.

Where a 'net benefit' principle cannot be used as a decision criteria, an alternative approach is to evaluate and select policy options based on their relative cost effectiveness in achieving a certain objective. A policy that achieves a given level of reduction in emissions at least-cost should be preferred over alternatives:

> *The principle that abatement should be achieved through least-cost means is of fundamental importance. Failure to adhere to it is likely to result in reduced community support for addressing climate change, due to the cost burden. In this sense, the principle is important not only for economic efficiency, but also for sustaining community support for abatement efforts over the long term.*[81]

Whatever net benefit is eventually achieved from structural changes to the economy resulting from emissions reduction policies, the choice of the mix of emissions reduction policies will determine whether or not abatement could have been achieved at lower cost to households and businesses. By selecting the least-cost mix of policy options, resources are available for other uses.

5.2 Types of emissions reduction policies

In 2011, the Productivity Commission identified 237 emissions abatement policies operating in Australia.[82] Many of the Australian Government and state and territory government policies were seeking to reduce emissions through support for the development of renewables generation. The study classified emissions reduction policies as explicit carbon prices, subsidies and other taxes, direct government expenditures, regulatory instruments, support for research and development, and other policies (Table 16). Use of a feed-in tariff to pursue emissions reduction is an example of a subsidy policy.

Who pays for the costs of the policies depends on the particular type of policy. Direct expenditure policies and support for research and development, and many of the subsidy policies, are paid for through government revenues and funded through taxation.

Regulatory instruments have direct costs on the regulated sector's producers and/or consumers which are transmitted to other sectors through, for example, the use of one sector's outputs as another sector's inputs to production.

Many of the policies — for example, explicit carbon prices — specifically seek to raise the cost of using energy. Other policies seek to subsidise renewables technologies to lower the costs of technologies until they become cost competitive.

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[81] PC 2007, p. 36.

[82] PC 2011a, p. 15.

Table 16: Classification of emissions reduction policies

Explicit carbon prices	*Regulatory instruments*
Emissions trading scheme — cap and trade	Renewable energy target
Emissions trading scheme — baseline and credit	Renewable energy certificate scheme
Emissions trading scheme — voluntary	Electricity supply or pricing regulation
Carbon tax	Technology standard
Subsidies and other taxes	Fuel content mandate
Capital subsidy	Energy efficiency regulation
Feed-in tariff	Mandatory assessment, audit or investment
Tax rebate or credit	Synthetic greenhouse gas regulation
Tax exemption	Urban or transport planning regulation
Preferential, low interest or guaranteed loans	Other regulation
Other subsidy or grant	*Support for research and development (R&D)*
Fuel or resource tax	R&D — general and demonstration
Other tax	R&D — deployment and diffusion
Direct government expenditure	*Other*
Government procurement — general	Information provision or benchmarking
Government procurement — carbon offsets	Labelling scheme
Government investment — infrastructure	Advertising or educational scheme
Government investment — environment	Broad target or intergovernmental framework
	Voluntary agreement

Source: Reproduced from Productivity Commission 2011, p. 15.

Some examples of emissions reduction policies are listed in Table 17.

Table 17: Examples of Australian Government and state and territory government policies

Policy	*Description*
RET – Large-scale renewable energy scheme (LRET)	The LRET creates a financial incentive to invest in renewable energy power stations, such as wind and solar farms. It does this by legislating demand for Large-scale Generation Certificates (LGCs). LGCs can be sold to entities (mainly electricity retailers) who surrender them to the Clean Energy Regulator (CER) to demonstrate their compliance with the RET scheme's annual targets. The revenue earned by the power station from the sale of LGCs is additional to that received for the sale of the electricity generated.
RET – Small-Scale Renewable Energy Scheme (SRES)	The SRES creates a financial incentive for households, small businesses and community groups to install small-scale renewable energy systems such as solar water heaters, heat pumps, solar PV systems, small-scale wind systems, or small-scale hydro systems. It does this by legislating demand for Small-scale Technology Certificates (STCs). STCs are created for these systems at the time of installation, according to the amount of electricity they are expected to produce or displace in the future.
Emissions Reduction Fund (ERF)	The ERF is a voluntary scheme that aims to provide incentives for organisations and individuals to adopt new practices and technologies to reduce their emissions. A number of activities are eligible under the scheme and participants can earn Australian carbon credit units (ACCUs). ACCUs can be sold to generate income, either to the Government through a carbon abatement contract, or in the secondary market. The CER runs reverse auctions to purchase emissions reductions at the lowest cost. The Australian Government provided $2.6 billion to establish the fund.
Australian Renewable Energy Agency (ARENA)	ARENA has two objectives: improve the competitiveness of renewable energy technologies; and increase the supply of renewable energy. ARENA coordinates support for research and development, demonstration and commercialisation of renewable energy technologies. ARENA has $2.5 billion in funding to 2022.
Clean Energy Finance Corporation (CEFC)	The CEFC operates like a traditional financier working collaboratively with co-financiers and project proponents to secure financing solutions for the clean energy sector. The CEFC provides financing solutions across the clean energy sector. It seeks to leverage funding for commercialisation and deployment of clean energy technologies. To date, the CEFC has committed over $1.4 billion in financing.
Renewables R&D funding and investment	Australian and overseas governments have large R&D programs related to renewable energy. Government incentives also induce private sector resources to be re-directed towards renewable energy R&D. UNEP estimates that governments directly spent $5.1 billion on R&D in 2014 related to renewable energy investments, and firms spent $6.6 billion.[83] UNEP estimates worldwide renewables energy investment in 2014 totalled $270 billion, of which $150 billion was related to solar energy investments. In 2013–14, the Queensland Government spent $10 million on R&D into renewable energy technologies development, and $1.4 million on building resilience and managing climate risk.[84]
Queensland environment and energy efficiency schemes	The Queensland Government has many emissions reduction policies. Some examples are: EcoBiz (provides tools and resources to assist business to implement efficient water, energy and waste management activities); the Solar Bonus Scheme; the Queensland Climate Adaptation Strategy (Q-CAS) and Climate Change (Coastal Hazards) Adaptation Program (CHAP); and the Queensland Climate Change Centre of Excellence. The Queensland Government contributes to energy efficiency programs run by Ergon Energy and Energex, such as the Energex PeakSmart Air-conditioning Program which provides households and businesses with financial incentives of up to $2000 for purchasing and installing PeakSmart-enabled air-conditioners.
Other policies	Examples of interstate schemes include: the South Australian Residential Energy Efficiency Scheme; the NSW Energy Savings Scheme; the ACT Energy Efficiency Improvement Scheme; the GreenPower Accreditation Program; and the Victorian Energy Efficiency Target (VEET) Scheme.

[83] United Nations Environment Programme (UNEP) 2015, p. 15.
[84] Office of the Queensland Chief Scientist 2015, p. 19.

5.3 Are solar PV owners fairly compensated for emissions reductions?

Some submissions stated that feed-in tariffs should be increased to compensate solar investors for any environmental benefits from emissions reduction. For example, responses to the Solar Citizens' survey stated that the feed-in tariff should:

- *factor in a price for the clean energy, as the polluting generators are profiting from pollution and not paying for it.*
- *be based on the wholesale cost PLUS any costs associated with the social, environmental benefits of the CO_2 reductions.*[85]

The Essential Services Commission's (ESC) Draft Report on the energy value of distributed generation could not reach a conclusion (Box 12).

Box 12: ESC Draft report: Energy value of distributed generation

On 6 May 2016, the Essential Services Commission released its Draft Report on the energy value of distributed generation. An overview of the ESC inquiry is provided in Appendix C.

The ESC concluded:

> *There is no economy-wide mechanism for determining the price of emissions currently in place. When such a mechanism existed in 2013-14, it operated alongside the RET scheme. Likewise, the Emissions Reduction Fund, which pays emitters to reduce (or avoid) their emissions, currently coexists with the RET scheme.*
>
> *… it appears the RET does not fully reflect the value these policy makers have attached to the benefit of avoided emissions.*

However, the existence of multiple programs, a single program or no program does not provide evidence of whether distributed generators are compensated for reducing emissions. The ESC did not assess whether distributed generation was already compensated for emissions reduction through the SRES.

The ESC went on to conclude:

> *[W]hether distributed generation should attract additional compensation for greenhouse gas abatement and the size of any additional payment is a matter for government policy.*

As a result, the ESC established a method for calculating emissions reduction and outlined how a 'deemed output tariff' could be included in a regulated tariff for distributed generation, but did not attach a monetary value. It noted that a deemed output tariff would increase costs for Victorian electricity customers.

Source: ESC 2016.

Other submissions considered that solar PV systems are already subsidised through Australian Government programs:

> *The potential abatement benefit of solar PV output is already rewarded via the upfront subsidy of renewable energy certificates provided under the SRES. These certificates covers fifteen years of deemed output, which equates to a subsidy of around $828–972 per kW installed in Queensland. On this basis, it is not clear what the justification would be for rewarding it a second time.*[86]
>
> *Presently, the environmental benefits of installing small-scale solar PV systems are accounted for through the assignment of Small Scale Technology Certificates (STC) as part of the Commonwealth's Small-scale Renewable Energy Scheme (SRES)…*[87]

5.3.1 Small-scale Renewable Energy Scheme (SRES)

The SRES is a part of the Australian Government's Renewable Energy Target (RET) policy. The objective of the RET is to reduce CO_2 emissions by increasing the proportion of electricity

[85] Solar Citizens, sub. 18, pp. 3–4.
[86] ESAA, sub. 37, p. 3.
[87] Origin Energy, sub. 24, p. 5.

generation derived from renewable energy sources and supplied to the Australian electricity market.

The SRES creates a financial incentive for households, small businesses and community groups to install eligible small-scale renewable energy systems such as solar water heaters, heat pumps, solar PV systems, small-scale wind systems, or small-scale hydro systems. Purchasers of solar PV systems receive a subsidy provided through Small-scale Technology Certificates (STCs) usually as an up-front reduction in the cost of purchasing a system. STCs are created at the time of system installation, according to the amount of electricity they are expected to produce or displace in the future.

The subsidy provided by the SRES leads to a higher rate of investment in solar PV panels than would occur otherwise, by reducing the capital costs of purchasing a system.

RET-liable entities are required to buy certificates, and surrender the certificates to the Clean Energy Regulator (CER) on a quarterly basis. The purchase of certificates is a legal requirement for liable entities, in accordance with the *Renewable Energy (Electricity) Act 2000* (see Appendix E for background information on the RET).

The number of STCs that can be created per solar PV system is based on its geographic location, year of installation, and the amount of electricity that is expected to be generated, up to a maximum of 15 years.

When creating STCs, the geographic location of the installation is taken into account. Four 'postal zones' are identified across Australia, each having a 'solar zone rating' with a higher rating indicating that a system would be expected to generate more electricity in that zone. The solar zone rating provides an estimate of the megawatt hours expected to be generated per kilowatt of system rated output in a particular zone. Much of Queensland's population is located in postal zone 3.

One STC is equal to approximately one megawatt hour of eligible renewable electricity either generated or displaced by the system.

It is possible for owners of renewable energy systems to create and sell the STCs themselves. However, in practice, installers of the systems usually offer a discount on the price of an installation, or a cash payment, in return for the right to create and sell the STCs. The evidence suggests that most of the STC subsidy is captured by solar PV owners rather than installers (see Appendix E).

5.3.2 Size of the capital subsidy provided by the SRES

In the case of an installation of a 3.0 kW system in Brisbane, with an eligible deeming period of 15 years for installations undertaken in 2015, and with a solar zone rating of 1.382, 62 certificates are created (3.0 x 1.382 x 15) (Table 18). If an installer can sell the STC at a price of $38 per certificate, then the maximum discount on the system purchase price that the installer would be willing to pass on to purchasers is $2363. How much of the value of the STCs is actually passed on to consumers depends on the administrative costs of meeting CER procedural requirements for creating and selling the certificates, as well as competitive market conditions.

Table 18: The subsidy provided by the SRES to the purchase of a solar PV system

System rated output in kW	*Postal zone*	*Solar zone rating*	*Eligible deeming period*	*No. of STCs created*	*Value of STCs @ $38/STC*
3.0 kW system	1	1.622	15yrs	73	$2774
3.0 kW system	2	1.536	15yrs	69	$2627
3.0 kW system	3	1.382	15yrs	62	$2363
3.0 kW system	4	1.185	15yrs	53	$2026

Notes: Postal zone 1 includes, for example, Birdsville and Cooladdi. Postal zone 2 includes, for example, Charleville, Longreach and Mount Isa. Postal zone 3 includes, for example, Brisbane, Cairns, Hervey Bay, Gold Coast, Goondiwindi, Port Douglas, Rockhampton, Stanthorpe, Toowoomba and Townsville. Postal zone 4 includes, for example, Hobart and Melbourne, but there are no major Queensland population centres in postal zone 4.

Source: QPC calculations.

The value of STCs reduces the price paid for an installed solar PV system. For a system installed in postal zone 3 in 2015 (say in Brisbane, Gold Coast, Hervey Bay, Rockhampton or Cairns), the value of STCs ranges from $788 for a 1.0 kW system to $5908 for a 7.5 kW system (Table 19).

As the gross price of systems can vary due to the brand and quality of panels and other equipment installed, the specific locational details of the installation (for example, roof characteristics), transport costs and competitive market conditions, the gross system prices below are shown as lower and upper estimates, but should still be considered as indicative.

The price reductions can be between 21 and 46 per cent, depending on location, system size and price. For a 3.0 kW system, the value of the STCs ranges from 33–40 per cent of the gross installed system price, excluding taxes. For a 5.0 kW system, the value of STCs is proportionally higher, ranging from 37 to 46 per cent.

Table 19: STCs subsidy as a proportion of solar PV system installed costs, excluding taxes

System rated output in kW	*Gross system price — lower estimate ($)*	*Gross system price — upper estimate ($)*	*Value of STCs ($)*	*STCs value as proportion of lower estimate price (%)*	*STCs value as proportion of upper estimate price (%)*
1.0 kW system	3038	3713	788	26%	21%
1.5 kW system	4049	4949	1182	29%	24%
2.0 kW system	4948	6048	1575	32%	26%
3.0 kW system	5847	7147	2363	40%	33%
4.0 kW system	7645	9343	3151	41%	34%
5.0 kW system	8656	10,580	3939	46%	37%
7.5 kW system	12,983	15,868	5908	46%	37%

Notes: System prices based on net system price information published by SolarChoice for Brisbane as at July 2015. The number of STCs calculated is for a system installed in postal zone 3, in the year 2015 (given a deeming period of 15 years).

Source: QPC calculations.

Taking the mid-point of estimated system prices, and assuming a 20-year useful life, the level of the SRES subsidy is between 2.8 and 2.9c/kWh generated. This rate of subsidy holds across system sizes. Another way to consider the level of the subsidy is that, assuming an export rate of 40 per cent, the household receives an additional 7.1c/kWh through the SRES for energy exported.[88]

The RET legislation includes a scheduled decline in the level of subsidy provided through STCs. The decline is implemented through successive decreases in the 'deeming period' used in the calculation of the number of STCs created upon installation of a system. For years prior to and including 2016, 15 years of generation are included in the creation of certificates, followed by 14 years for systems installed in 2017, 13 years for systems installed in 2018, and so on, until 2030 where only one year is eligible (discussed in Appendix E).

5.3.3 Conclusion

Given the subsidy provided through the SRES, and that the subsidy is provided with the objective of achieving an environmental benefit through lower CO_2 emissions, the evidence suggests that solar PV investors are already financially compensated for reducing emissions.

5.4 Abatement costs under a subsidised feed-in tariff

We have concluded that the SRES fairly compensates solar PV investors for emission reductions. The analysis below considers whether an additional payment through a feed-in tariff would be a fair and cost-effective way to reduce emissions.

5.4.1 Emissions intensities

As previously discussed, the electricity generated by a solar PV system displaces generation from thermal sources.

The amount of abatement depends on the emission intensities of the particular generation source displaced.[89] Different thermal fuel types have different emission intensities (Table 20). In Queensland, one megawatt hour of solar PV generation which displaces generation from black coal is estimated to reduce emissions by 0.861 tonnes on average (different black-coal-fired generating plants will differ in their emission intensities).

Table 20: 2016–17 to 2020–21 average emission intensities, (t CO_2/MWh)

Fuel type	*Qld emissions intensity*	*Whole of National Electricity Market (NEM) emissions intensity*
Black coal	0.861	0.891
Brown coal	–	1.240
Liquid fuel	0.811	0.826
Natural gas	0.425	0.423

Source: ACIL Allen Consulting 2015.

In contrast, if the same increase in solar PV generation displaces natural gas generation, then the amount of carbon abatement is reduced to 0.425 tonnes on average. Outside of Queensland, solar

[88] The SRES subsidy per kWh exported calculation is based on an investment in 2015–16 in solar zone 3, a system useful life of 20 years, an average export rate of 40 per cent, and base case system prices and generation volumes. The subsidy per kWh exported is around 7.1 cents for all residential system sizes. Under a 30 per cent export rate, the subsidy increases to 9.5c/kWh. Under a 50 per cent export rate, the subsidy decreases to 5.7c/kWh. An argument could be made to assume a useful life of 25 years, but the generation volumes used in the calculations assume generation under fairly ideal conditions and no decay in panel efficiency over time. Sensitivity testing and the degree to which chosen assumptions are 'conservative', are discussed in Appendix D.

[89] A full life-cycle analysis would go beyond comparing differences in emissions from the production of energy to also include consideration of the energy consumed and resulting emissions from the production and transport of solar PV panels compared to the building of large-scale generation stations.

PV generation which displaces generation from brown coal sources results in a greater reduction in CO_2 emissions at 1.240 tonnes on average.

To estimate potential additional abatement through a subsidised feed-in tariff, we considered a scenario that raised the feed-in tariff from a price based on avoided costs to a price set equal to the retail import price. In 2015–16, the variable component of Tariff 11 is roughly 22c/kWh versus a feed-in tariff of around 6c/kWh based on an avoided cost approach (the base case).

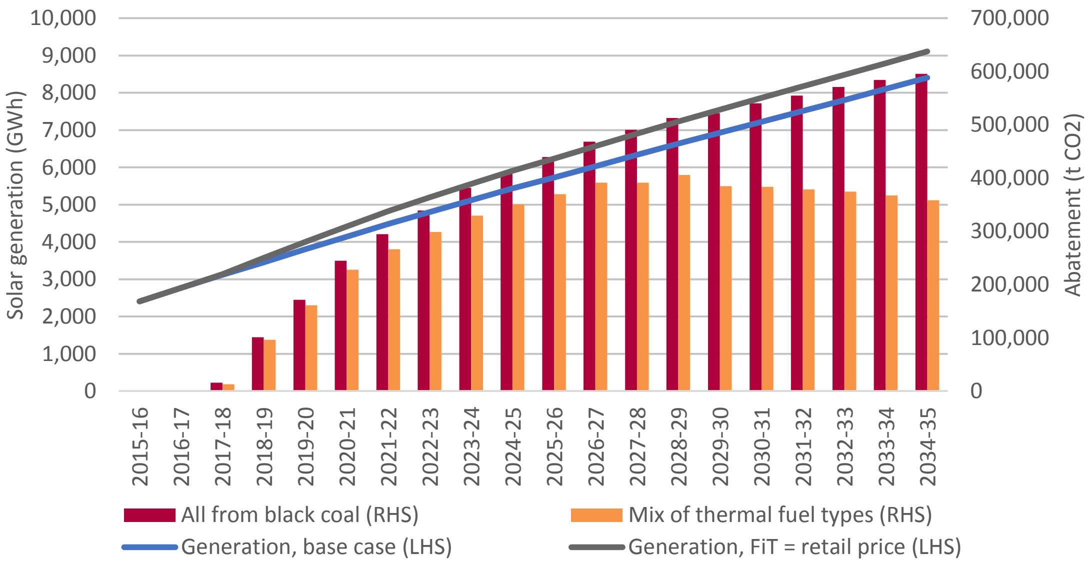
The volume of solar PV generation increases under the subsidised feed-in tariff compared to the base case as investment in solar PV panels is higher (Figure 28). The additional generation is represented by the difference in the two graphed lines. The higher level of solar investment and generation under the subsidised feed-in tariff leads to a larger amount of thermal generation being displaced, and therefore reduces Australian emissions.

Two scenarios were calculated, based on the emissions reduction from the displacement of:

- black coal sources only; and
- a mix of thermal fuel types.

ACIL Allen modelling for the QPC investigated the impacts of a Queensland Renewable Energy Target (QRET).[90] The modelling indicated that in the early stages of the QRET black coal would be displaced, but, over time, progressively more abatement would come from natural gas generation, which has a lower emissions intensity than black coal. Under the 'black coal only' scenario, annual emissions reductions increase each year, while under the mixed thermal fuel scenario annual emissions reductions reduce somewhat after 2029–30, due to the lower emissions intensity of natural gas (see the columns in Figure 28).

Figure 28: Reduction in emissions under a subsidised feed-in tariff



Note: Data based on modelling of the impact of a feed-in tariff equal to the variable component of the retail tariff.

Source: QPC calculations based on ACIL Allen Consulting 2015.

[90] The Queensland Government is investigating a 50 per cent renewable energy target to be achieved by 2030.

5.4.2 The cost of abatement

If a feed-in tariff is set at a level which includes a subsidy, investment in solar PV systems receive two subsidies:

- the subsidised feed-in tariff (the gap between the feed-in tariff and a feed-in tariff based on avoided costs); and
- the value of the STCs provided through the SRES that reduces initial capital costs.

For a feed-in tariff set at the retail price, if the additional solar generation leads to a reduction in black coal generation only, then 3.2–5.7 million tonnes of abatement is achieved over the period from 2017–18 to 2054–55 (Table 21). If the reduction comes from a mix of thermal fuel sources, then the resulting abatement is lower, at between 2.4 and 4.2 tonnes of CO_2 abatement.

The subsidy through the feed-in tariff is assumed to end in 2034–35, which was the last year of the modelling projections. However, as the subsidies result in a capital investment and the useful life of the panels is assumed to be 20 years, the abatement benefits were calculated out to 2054–55. Between 2034–35 and 2054–55, the stock of 'additional' solar PV systems subsidised would progressively be retired as each vintage of capital reached its useful life.

The subsidy equivalent[91] required to achieve the abatement in Figure 28 depends on the group of solar owners receiving the subsidies. Four subsidy or policy scenarios were analysed:

(1) all existing and new systems;

(2) all existing systems (other than SBS systems), plus new systems under base case growth, plus additional systems resulting from the feed-in tariff subsidy;

(3) all 'new' systems. These systems include all new systems resulting from base case growth plus additional systems resulting from the feed-in tariff subsidy; and

(4) only 'additional' systems resulting from the feed-in tariff subsidy. These systems are additional to those under the base case growth scenario. While instructional, this scenario is impractical (see discussion below).

[91] The subsidy equivalent is defined as the assistance provided per unit of output or activity multiplied by the number of units or activities. For example, if a feed-in tariff subsidy of 3c/kWh is given and 1000 kWh are exported, then the subsidy equivalent is $30 ($0.03 x 1000).

Table 21: The subsidy equivalent cost of abatement

Policy scenarios	*Subsidy equivalent FiT only*	*Subsidy equivalent FiT + SRES^*
(1) Subsidy paid to exports from all existing and new systems ($m)	1721–2479	1865–2654
(2) Subsidy paid to all exports, excluding exports from premium SBS systems ($m)	1385–2063	1530–2238
(3) Subsidy paid to exports from all new systems ($m)	888–1364	1032–1539
(4) Subsidy paid to exports from 'additional' systems ($m)	107–165	252–340
	Black coal only	*Mix of thermal fuels*
Abatement (millions of tonnes of CO_2)	3.2–5.7	2.4–4.2
	Implicit abatement subsidy (FiT + SRES)	
Policy scenarios	*Abatement from black coal only*	*Abatement from mix of thermal fuels*
(1) Subsidy paid to exports from all existing and new systems ($/t CO_2)	463–590	626–762
(2) Subsidy paid to all exports, excluding exports from premium SBS systems ($/t CO_2)	390–484	528–625
(3) Subsidy paid to exports from all new systems ($/t CO_2)	268–327	363–422
(4) Subsidy paid to exports from 'additional' systems ($/t CO_2)	59–80	80–103

^ The SRES subsidy equivalent is $145–$175 million.

Notes: Data based on modelling of the impact of a feed-in tariff equal to the variable component of the retail tariff. Export rate of 50 per cent assumed. Lower and upper bounds based on discount rates of 5 and 10 per cent. Discount rate for abatement (millions of tonnes of CO_2) calculated over period 2017–18 to 2054–55. Discount rate for subsidies calculated over period 2017–18 to 2034–35 which was the projection period used in ACIL Allen modelling for this inquiry. The additional time period for abatement reflects the assumed useful life of solar PV systems set at 20 years (consistent with most financial returns calculations undertaken in this report). The 'mix of thermal fuels' abatement scenario is based on ACIL Allen modelling of a potential QRET undertaken for the QPC's broader electricity inquiry. See ACIL Allen Consulting, 2014, pp. 113–14 for the rationale for discounting the volume of abatement. The estimates differ from those in QPC, 2016 due to different modelled scenarios and assumptions, although both approaches produce high abatement cost estimates.

Source: QPC calculations based on data from ACIL Allen Consulting 2015.

Under **scenario 1**, the NPV of the feed-in tariff subsidy is $1.721–$2.479 billion (calculated over the period 2017–18 to 2034–35 using discount rates of five and ten per cent). Including the SRES subsidy of $145–$175 million, the subsidy equivalent increases to $1.865–$2.654 billion.

Given the subsidies already paid to SBS participants, for **scenario 2** it was assumed that the policy would be designed to exclude exports from those systems (currently SBS owners in regional areas receive 44c/kWh, but do not receive the regulated feed-in tariff of roughly 6 cents. In SEQ, SBS owners receive the 44c/kWh cents plus any market offer feed-in tariff offered by their retailer). The NPV of the feed-in tariff and SRES subsidy equivalent under discount rates of 5 and 10 per cent ranges from $1.530 billion to $2.238 billion.

Under **scenario 3**, the NPV of the subsidised feed-in tariff and SRES provide a combined subsidy equivalent of $1.032–1.539 billion. Targeting the subsidy to only new systems from 2017–18 would likely require some form of administrative arrangements similar to those used in the SBS.

If a subsidy could be targeted to only truly 'additional' systems — **scenario 4** — then the combined feed-in tariff and SRES subsidy equivalent is significantly less at $252–$340 million. However, there is no practical way to implement such a policy as there is no way to distinguish between new investment that occurred because of the subsidy and new investment that would have occurred in any case. The much lower cost of abatement estimates for scenario 4 highlight the importance of achieving additionality in the design of subsidy policies.

The magnitude of the cost of abatement estimates is not influenced greatly by the particular feed-in tariffs. Appendix D presents cost of abatement estimates based on different feed-in tariffs.

The difference in the estimated subsidy across the four scenarios leads to varying estimates of the cost of abatement. Targeting the subsidy at the exports from all new and existing systems (scenario 1) results in an implicit abatement cost of \$463–\$762 per tonne of CO_2, depending on the discount rate used and the thermal fuel displaced. Targeting the subsidy at exports from all new systems (scenario 3), leads to an implicit abatement cost ranging from \$268 to \$422 per tonne of CO_2.

Although there are differences in the methods used to estimate the cost of abatement, estimates are broadly consistent with those produced by other national and international studies, in that subsidies to solar PV is a high-cost abatement policy. Wood, Blower and Chisholm[92] found that the economic cost of emissions reductions to 2030 due to solar PV is more than \$175 per tonne of CO_2. Burtt and Dargusch[93] estimated the cost of abatement using household solar PV at between \$78 and \$101 per tonne in 2015.

The Productivity Commission produced implicit abatement subsidy estimates for the small-scale component of the RET scheme, and state and territory feed-in tariff schemes of \$177–\$497 per tonne of CO_2 abatement. The lower and upper bounds were determined by a combination of different assumptions for discount rates, export rates and the useful life of panels. The estimates were based on conditions and scheme details prevailing in 2010 for both the design of the RET and state and territory feed-in tariffs. These schemes have been subject to significant changes since that time. The conclusion was that:

> *The small-scale component of the RET and the state and territory FITs nevertheless remain relatively high-cost policies achieving little abatement.*[94]

ACIL Allen produced estimates of the cost of the SRES component of the RET of \$164–\$191 per tonne of CO_2 abatement.[95] The estimates are, in effect, estimates of the cost of abatement of solar PV generation, as they exclude the resource costs of solar water heaters. While the cost estimates appear higher than those presented above, the estimates are based on a different methodology. Rather than calculating the subsidy equivalent provided to solar owners, the study calculated the NPV of the economic resource costs of electricity generation.[96] The study found that the abatement costs of solar PV was significantly higher than for large-scale renewables:

> *Abatement costs are significantly lower for the LRET compared with the SRES (\$40-\$72/tonne compared with \$164–\$191/tonne). This is primarily a result of the underlying levelised cost of energy from large-scale technologies (for example wind at \$80–\$100/MWh) compared with small scale solar PV which even at today's costs is around \$180–\$200/MWh. Therefore, the more skewed renewable policy is toward subsidising solar PV relative to large-scale technologies, the higher the effective abatement cost of the policy.*[97]

[92] Wood et al. 2015, p. 16.
[93] Burtt & Dargush 2015.
[94] PC 2011b, p. 15.
[95] ACIL Allen Consulting 2014.
[96] Economic resource costs included: capital costs of new development; capital costs associated with refurbishments of existing power stations; fixed operating and maintenance costs; variable operating and maintenance costs; and unserved energy (a national value placed on any energy which is demanded but not supplied). See ACIL Allen Consulting 2014, p. 113.
[97] ACIL Allen Consulting 2014, p. 115.

Recent US estimates indicate that the implied cost of abatement of residential solar PV is US $126 if solar PV displaces coal only, and US $335 if it displaces gas.[98]

5.5 A subsidised feed-in tariff achieves relatively low additional abatement at high cost

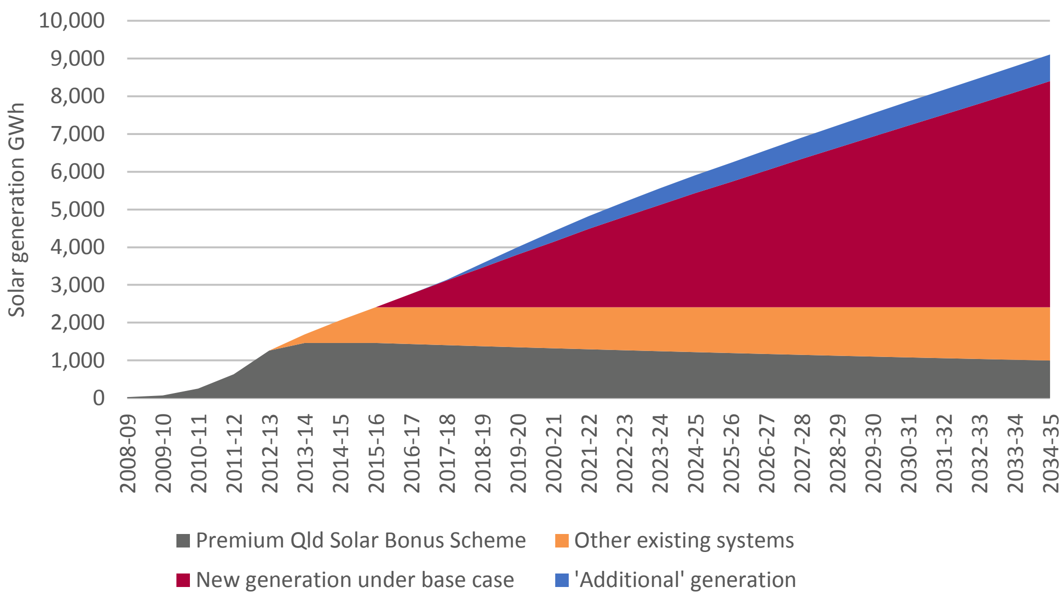
As outlined in Chapter 2, solar PV is projected to grow in Queensland with no change to policy settings.

Under a feed-in tariff set to the retail price scenario (22c/kWh), by 2024–25 the share of solar generation will be:

- 21 per cent from the SBS stock of PV systems;
- 20 per cent from other existing systems;
- 51 per cent from panels added under the base case projections; and
- 8 per cent from panels added in response to a feed-in tariff set at the retail electricity price (Figure 29).

By 2034–35, the share of solar generation will be 16 per cent from existing systems, 66 per cent from base case growth, and 8 per cent additional generation from the subsidised feed-in tariff.

Figure 29: Existing stock, base case growth and additional solar PV generation (Scenario: feed-in tariff = variable component of retail tariff)



Source: ACIL Allen Consulting 2015; QPC calculations.

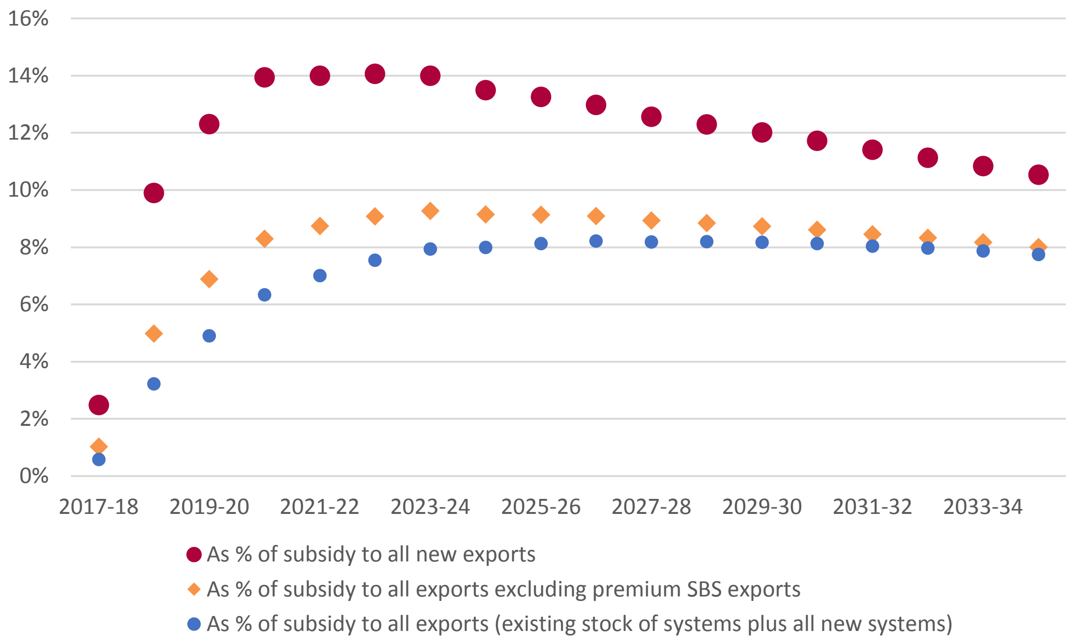
Since a subsidy provided through feed-in tariffs would likely apply to the exports from existing systems (other than SBS systems), at least 85 per cent of the subsidy would go towards increasing the financial return to existing systems, and system investments projected to occur with the SRES subsidy only, rather than resulting in additional solar generation being brought online.

In any given year, the subsidy paid to 'additional' solar PV (scenario 4) is at most 14 per cent of the total subsidy paid (Figure 30). A large proportion of the total subsidy goes to exports from systems

[98] Lazard 2015, p. 6.

that were installed in earlier years. For example, if the subsidised feed-in tariff is also paid to exports from other existing systems (scenario 2), then the proportion of the subsidy paid for additional generation is at most 9.3 per cent.

Figure 30: Proportion of annual subsidies paid resulting in 'additional' generation



Source: ACIL Allen Consulting 2015; QPC calculations.

5.6 Relative costs of abatement policies

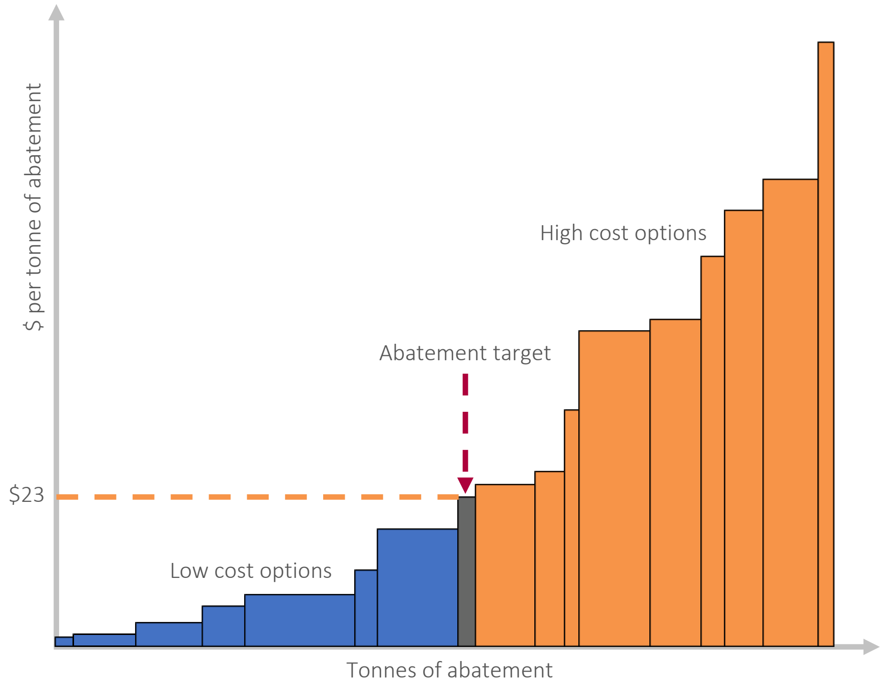
Abatement cost estimates vary widely by policy option. This is illustrated in Figure 31 which presents a hypothetical set of policy options ranked by their respective costs of abatement (referred to as a marginal abatement cost curve). Small-scale solar PV is a relatively high-cost abatement option (sits to the right of the marginal abatement cost curve), although continued price reductions make it less so.[99]

The Australian Treasury modelled the economic effects of domestic climate change mitigation policy scenarios to 2050.[100] The carbon price modelling was based on a starting carbon price of \$20–\$23 per tonne of CO_2-e in 2012–13, moving to a flexible price scheme within three years. The carbon price is the price that equals the cost of the marginal abatement option.

[99] A number of organisations have produced marginal abatement cost curves which seek to provide estimates of the abatement cost of alternative policy options (see for example, ClimateWorks Australia 2010, Wood et al. 2015 and PC 2011a, p. 80). ClimateWorks 2010 ranked 72 options for reducing emissions by their estimated abatement cost. Subsidies to solar PV investment were shown to be a high cost option at the time of the report in 2010. However, as the level of subsidies through premium feed-in tariffs have been wound back by state governments and solar PV system costs have decreased significantly, the abatement costs of solar PV would be expected to have fallen.

[100] Australian Treasury 2011.

Figure 31: A stylised marginal abatement cost curve



The April 2015 Emissions Reduction Fund (ERF) auction achieved an average abatement price of $13.95. A breakdown of the projects awarded provides information on the types of projects achieving the relatively low abatement cost (Table 22).

Table 22: Number of projects registered under the Carbon Farming Initiative/Emissions Reduction Fund 2014–15, by method

Method	*New projects in 2014–15*	*Cumulative projects to 30 June 2015*	*Percentage of total projects*
Agriculture	7	14	5%
Energy efficiency	2	2	1%
Industrial fugitives	0	0	0%
Savanna management	24	35	13%
Transport	2	2	1%
Vegetation	90	134	47%
Waste	14	91	33%
Total	139	278	100%

Note: With the introduction of the Emissions Reduction Fund, the earlier Carbon Farming Initiative has been incorporated within the fund.

Source: Clean Energy Regulator n.d.

The second ERF auction was held in November 2015. The CER reported that:

- 129 contracts were awarded committing to purchase 45.5 million tonnes of abatement;
- contracts were awarded to 77 contractors covering 131 projects;
- the total value of contracts awarded was $557 million; and

- the average price per tonne of abatement was $12.25.[101]

Despite problems in making comparisons across different abatement cost estimates, the average price per tonne of abatement would appear to be much lower than abatement cost estimates for small-scale solar PV systems.

Given the above estimates, small-scale solar investors receive a higher level of subsidy through the SRES than through other policy options for reducing CO_2 emissions. This further supports the argument that solar investors are already financially compensated for reducing emissions:

> *While the environmental impact of embedded generation is likely to attract significant debate, Stanwell notes that there are a number of other sources of abatement which receive less compensation, including the Federal Government's Emissions Reduction Fund, which has had clearing prices to date of $13.95/t and $12.25/t. Accordingly, Stanwell believes that the SRES already provides at least sufficient payment for the environmental benefits associated with the installation of solar PV.*[102]

The Expert Panel Review of the RET found that the SRES, which predominantly goes to solar PV installations, is a high-cost option to achieve CO_2 reductions:

> *The cost of reductions in CO_2-e emissions achieved by the SRES is very high, in the order of $100–$200 per tonne. On this basis its role as an emission reduction tool cannot be justified when other CO_2-e emissions reduction policies are available at much lower cost.*[103]

5.7 National emission reductions policies are lower-cost

National policy instruments are better suited to reducing emissions at least-cost than state and territory policies, particularly where national policies are undertaken within an internationally agreed and binding approach to emissions reductions (Box 13). There was broad support from stakeholders for a least-cost, technology-neutral, national approach to emissions reduction. [104]

[101] CER 2015.
[102] Stanwell Corporation Limited, sub. 30, p. 9.
[103] Expert Panel Review of RET 2014, p. 76.
[104] See for example, Bruce Cooke, sub. 23, p. 1; APA Group, sub. DR7, p. 3; AEC, sub. DR9, p. 2; ENA sub. DR20, p. 2; Origin Energy, sub. DR15, p. 3; AGN, sub. DR21, p. 2.

Box 13: Implications of a global externality for state policy

To the extent that CO_2 emissions increase global temperatures and pose a risk, it is a global externality and problem. As a global problem, the geographic source of emissions within Australia is of no practical relevance. While a national target is addressed most effectively by national policy, the potential for unwarranted supplementary policies to emerge is magnified in a federation such as Australia.

Climate change initiatives at lower tiers of government are likely to conflict with national objectives, increase abatement costs, duplicate effort and encourage double counting of abatement. Moreover, if states and territories were to engage in bidding wars — through subsidies for renewable activities or 'compensation' for carbon-intensive activity — the location-related distortions would be of no benefit to the nation. As an extreme illustration, a negative net outcome would arise if, say, wind generators were attracted to subsidy-rich, but relatively wind-poor, locations.

There is a particular need to guard against governments introducing new policies to protect localised investments that arose from schemes that might be slated for abolition — for example, replacing mandated renewable energy targets with subsidies for renewable activities (including uncommercial feed-in tariffs).

State and territory (and local) government initiatives are best confined to:

- research on climate change impacts, adaptation and structural adjustment, where geographic location is an important consideration;
- providing general information on energy efficiency where there might not necessarily be benefits from national coordination;
- removing regulatory or other impediments to adoption of low-emissions technologies; and
- ensuring expected emissions prices are factored into their planning and investment.

Source: PC 2008, pp. 42–43.

National policies are less likely to distort business locational decisions within Australia. Emissions reduction policies generally increase the cost of doing business, so that there is an incentive for businesses to relocate to states that impose fewer costs through environmental policies. State and territory differences in business costs also affect new investment whether from existing businesses, the creation of new businesses or foreign investment.

5.8 Local pollutants

Coal and gas-fired power stations emit a range of substances that can be harmful to the environment and/or human health, including particulate material (PM_{10}), sulfur dioxide (SO_2), and nitrogen oxides. As the impacts of these emissions are site- or region-specific, state policies take on a relatively larger role in addressing local pollutant problems than in the case of CO_2 emissions.

Several submissions indicated that solar PV should be rewarded for displacing traditional generation and reducing local pollutants.[105]

Generator substance emissions are subject to both national and state regulatory framework requirements, including through:

- the National Environment Protection (Ambient Air Quality) Measure;
- the National Pollution Inventory (NPI) Scheme;
- the Queensland *Environmental Protection Act 1994*;
- the Queensland *Environmental Protection Regulation 2008*; and

[105] Queensland Conservation Council, sub. 40, pp. 4–5; Australian Solar Council, sub. 39, p. 2; Trevor Berril, sub. 33, p. 3.

- the Queensland *Environmental Protection (Air) Policy 2008*.

The national measures and schemes work in conjunction with state monitoring activities. Appendix F provides background information on the regulatory frameworks applying to substance emissions and ambient air quality, as well as the outcomes of monitoring programs.

National and state regulators require that generators monitor and report on emissions of a large number of substances. State regulations also require that electricity generators obtain and maintain an Environmental Authority to operate, which specifies maximum release limits of substances. State regulators have a range of tools to ensure compliance with EA requirements.

Queensland ambient air quality reporting indicates that there are relatively few instances of air quality standards being exceeded. In 2014, where exceedances did occur, they were not related to electricity generation. Further, monitoring indicates improvements in ambient air quality over time in Queensland.

A feed-in tariff subsidy would be a poor policy instrument for addressing any harmful effects of local pollutants. Where the source of pollution can be identified and the impacts are localised, it is generally more effective and efficient to target the polluter directly through policies that impose the cost of pollution on polluters, rather than indirectly through a subsidy to unrelated activities. If the existing regulatory framework for addressing local pollutants was not effective, then reviewing that framework would be recommended, rather than supporting a higher feed-in tariff for solar PV.

A feed-in tariff subsidy would also be poorly targeted, in the same way it poorly targets CO_2 emissions and results in a very high cost of abatement. Even so, if a feed-in tariff subsidy was chosen, then it is likely that the implied level of an optimal subsidy is well within the bounds of the subsidy already provided by the SRES — given the existing regulatory substance monitoring and licensing framework in place, and the indications of few exceedances and improving air quality over time.

5.9 Neutrality, simplicity and transparency

A subsidy paid through a feed-in tariff is not technology-neutral, as it subsidises a particular class of technologies (renewables) as well as a specific form of renewables (solar PV generation). A feed-in tariff also directs resources to a specific scale of the technology (small-scale solar PV generation). It also only subsidises exports, whereas it is overall generation that has a relationship with abatement.

Highly selective assistance policies are unlikely to lead to cost-effective and efficient abatement policies (Box 14). Other mechanisms, such as, carbon taxes, emissions trading schemes, and the ERF reverse auction process, are better designed to allow individuals and businesses to find solutions which result in lower costs for a given level of emissions reduction.

Box 14: Characteristics of least-cost abatement policies

The Energy Networks Association commissioned a study to quantify the impacts of alternative policy approaches to achieve the stated national carbon emission reduction target by 2030. Three different approaches to achieving the emissions reduction target were modelled:

- *Business as usual scenario*: assumes the continuation of the diverse range of various state and federal abatement initiatives which prescribe specific technologies or scale (for example, small-scale generation), and the extended use of a binding safeguards mechanism which limits sectoral emissions with trading of emissions permits;
- *Level playing field scenario*: assumes the current range of abatement initiatives are reformed and made technology and scale neutral. A liability trading mechanism and carbon price also form part of the modelling in this scenario; and
- *Explicit carbon price scenario*: assumes a whole-of-economy explicit carbon price is established either through a carbon tax or emissions trading scheme, and that all other abatement policies (such as the RET and SRES) are removed.

The study found that achieving the national emission reduction target at least-economic cost was associated with market-based mechanisms applied broadly across the energy sector and technology-neutral policies.

The study also found that the lowest residential electricity bills occurred under policies that provided a level playing field for technologies so that least-cost emissions reduction policies were utilised, and where trading of emissions reduction liabilities was allowed.

Source: Australian Gas Networks, sub. DR21; Jacobs 2016.

In addition, although an increase in regulated feed-in tariff appears to be a simple policy to implement, important administrative complications result from the need to determine eligibility and avoid unintended outcomes, which may require additional regulatory interventions. Experience with the SBS and similar premium feed-in tariffs in other states has shown that this results in neither simple nor transparent arrangements.

5.10 Summary

The terms of reference for this inquiry ask us to assess whether feed-in tariffs reflect the public and consumer benefits of solar exports. It also requires us to consider whether solar PV owners are already compensated for such benefits through existing renewable energy programs, rebates and market contracts.

The objective of the SRES is to lower the price of systems so that the rate of investment in systems will be higher than otherwise, resulting in reductions in emissions below what would have occurred. Given the SRES subsidy and price reductions in solar PV systems, under most scenarios, investment in solar PV systems provides a reasonable financial return to investors.

Given the significant uncertainty surrounding emissions reduction policies, their impacts on climate, and the net benefits that might result over very long timeframes, it is not possible to conclude with certainty that the subsidies provided by the SRES and other government policies either fully ‘compensate’ or ‘overcompensate’ solar investors for any environmental benefits flowing from their decision to invest in solar. Even so, it is clear that the SRES has a large impact on the financial return to investment, and compares very favourably to the price paid for other abatement activities.

A subsidised feed-in tariff does not perform well against the objective of achieving as much additional abatement as possible at the lowest possible cost. On the contrary, it achieves little additional abatement at a relatively high cost.

Findings

5.1 Investors in solar PV systems receive a subsidy from the Small-Scale Renewable Energy Scheme (SRES) to reflect emissions reduction.

5.2 An additional subsidy paid through a feed-in tariff for reducing emissions would be poorly targeted and result in a high cost of abatement, as well as large cross-subsidies between electricity consumers.

5.3 Better and fairer policy options are available to achieve carbon abatement at a lower cost than can be achieved by subsidising electricity exports from solar PV. Efficient national and international policies should be used to address global problems.

Recommendation

5.1 The Queensland Government should not increase feed-in tariffs to pay solar investors for reducing carbon emissions. Investors already receive a subsidy from the SRES for emissions reduction.

6 OTHER ECONOMIC AND SOCIAL BENEFITS: AN ASSESSMENT

The terms of reference ask us to investigate a range of public and consumer benefits from solar exports. Beyond the competition issues and environmental benefits examined in Chapters 4 and 5, a number of other benefits have been proposed for inclusion in a feed-in tariff. These include that mandated feed-in tariffs can:

- *develop or expand the residential solar PV industry;*
- *create jobs in the solar industry, leading to an increase in overall employment in Queensland;*
- *provide social benefits to the community; and*
- *reduce wholesale market prices and network infrastructure costs.*

This chapter assesses these rationales for setting feed-in tariffs.

Key points

- A range of reasons have been proposed for regulating feed-in tariffs, such as industry development, electricity market and social benefits. We have not identified a case to increase solar feed-in tariffs for these reasons.
- *Industry development and job creation:* Mandating solar feed-in tariffs to induce solar industry development and employment will be paid for by other consumers. Subsidising solar exports for industry development reasons will increase electricity costs for other businesses and households (including the least well-off consumers) and is likely to have an overall negative impact.
- *Generation costs and wholesale market impacts:* Solar PV has raised the cost of generating electricity in Queensland, with an estimated additional cost in the order of $75–$150 million in 2015. However, as the price of solar PV continues to decline, so will the additional cost of generation due to solar PV.

  Solar PV owners should not be paid for any impact on wholesale prices. Governments do not reward generators for reducing the wholesale price, just as suppliers in other markets are not paid for increasing supply. Paying solar PV owners for any reduction in wholesale market prices would likely result in overall higher electricity prices for Queensland consumers.
- *Network costs*: Solar PV may be able to defer network expenditure depending on specific location, penetration level and load characteristics. However, analysis of network data has not identified material network savings from solar PV in Queensland, and to the extent that savings may arise from 2015 to 2020, they are unlikely to outweigh the additional costs incurred from integrating solar PV onto the network.
- *Social benefits:* We have not identified specific social benefits from solar PV exports that would warrant an increase in the feed-in tariff.

6.1 Industry development, employment creation and social benefits

6.1.1 Solar industry development

A primary motivator for setting premium feed-in tariffs around the world has been to develop and support the renewable energy industry. The World Future Council, for example, states that a well-designed and implemented feed-in tariff can drive economies of scale in the renewables sector, increasing investment and demand, expanding manufacturing, and reducing costs.[106]

Setting feed-in tariffs for industry development rests on the premise that while an industry may not initially be competitive, government support can allow an industry to produce cost efficiencies through economies of scale and 'learning by doing,' leading to its emergence as a competitive industry:

> *A case-study in point is Germany where feed-in tariffs have been the central policy instrument in driving the rapid expansion in solar PV investment to such an extent that considerable economies of scale and scope have been achieved which have been responsible for significantly driving down the ($/Wp) costs of panels and inverters as well as the feed-in tariff rates, themselves, over time.*[107]

Some submissions advocated for higher feed-in tariffs to develop or expand the residential solar PV industry in Queensland, arguing that regulated feed-in tariffs:

- will encourage solar investment, leading to solar industry development and job creation;[108]
- have been successfully used in other countries to underline strong and rapid development of solar and other renewable energy industries.[109]

There is evidence that feed-in tariffs, and particularly premium feed-in tariffs offered by state governments, played a role in the rapid expansion of the residential solar PV industry in Australia.[110] A government subsidy generally increases production in any assisted industry. While that may make such a subsidy outwardly attractive, it will not necessarily be beneficial for the solar PV industry in the longer term and may come at an overall cost to the Queensland community:

- There may be benefits to the solar industry, but the costs to support that development are borne by other businesses and consumers, which will reduce income and employment in other sectors.
- Development may only be sustainable with ongoing subsidies and may result in unintended consequences, including if subsidies are withdrawn at a later time.

The solar PV sector in Queensland is mature

With one in four homes having solar PV, the solar power industry is well-established in Queensland. The Queensland Conservation Council noted that while most of the energy conservation industry is still embryonic, solar PV is the exception.[111] Bell and Foster stated that residential solar PV has moved beyond being an infant industry and therefore no longer requires infant industry support.[112] In addition, solar PV installations continue to grow (with more than 40,000 additional solar PVs connected in Queensland in 2014–15).

Energex noted that:

> *on average between 2,000 and 2,500 solar systems are connected each month in SEQ and that the solar industry has continued to evolve to meet the needs of the SEQ market, for example through the use of solar leasing or solar power purchase agreements (PPAs).*[113]

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[106] World Future Council n.d., pp. 2–3.
[107] University of Queensland, Global Change Institute, sub. 28, p. 4.
[108] John Sheehan, sub. 20, p. 8; Australian Solar Council, sub. 38, p. 4.
[109] University of Queensland, Global Change Institute, sub. 28, p. 9.
[110] It is difficult to isolate the impact of feed-in tariffs compared to other factors driving take-up such as the SRES and falling prices for solar PV panels.
[111] Queensland Conservation Council, sub. 39, p. 2.
[112] Bell & Foster 2012, p. 16.
[113] Energex, sub. 33, p. 5.

Origin Energy's submission to the QPC's Electricity Pricing Inquiry noted:

> *Despite the closure of the 44c/kWh scheme, we expect solar PV installations to continue growing strongly, without the need for further subsidies or targets.*[114]

The economic impact is likely to be negative

While the growth of the solar PV industry may be beneficial, it does not necessarily follow that growth induced through regulation or subsidies must also be beneficial. As noted by Origin Energy:

> *it is difficult to argue that [high feed-in tariffs] have led to efficient investment decisions, in the sense that they represent consumers responding to artificially low prices with significant costs paid for either by governments or other consumers. Whilst domestic installation costs became more efficient as a result of these subsidies, the underlying cost curve for solar PV systems has continued to fall largely due to external factors, such as breakthroughs in research and development and improved economies of scale in foreign manufacturing. Using feed-in-tariffs to encourage the installation of solar PV therefore has limited impact on the underlying costs of the technology and may result in consumers paying more for artificially priced products than they would in an unregulated market.*[115]

Targeted industry support is generally associated with a reduction in economic performance (see for example, Krugman, Industry Commission, Calcagno and Thompson and QCA). [116] As noted by Krugman, there are no clear cut cases of successful industrial targeting, but there is evidence of failures, in some cases disastrously so.

In the case of solar feed-in tariffs, a subsidised feed-in tariff increases electricity prices. Higher electricity prices will effect growth and employment in other sectors, particularly trade-exposed sectors such as manufacturing, agriculture and mining.[117] Many businesses operate in highly competitive markets, with limited ability to modify consumption and limited ability to change the prices they offer to market.

Where government intervention targets industry development, as opposed to market failures like pollution, then the overall impact is likely to be negative.[118] This is because a dollar taken from households or business to support solar industry development means there is a dollar less to be spent elsewhere. Where government intervention results in a shift of resources away from higher-value uses the overall impact on economic activity will be negative.

Industry development subsidies can have unintended consequences

Industry development regulation or subsidies are highly susceptible to unintended consequences.

For example, Nelson, Simshauser & Nelson[119] found premium feed-in tariffs around the world to be associated with a temporary but unsustainable 'boom–bust' cycle, where the industry expands following government support but subsequently contracts following a reduction or removal of subsidies.

Outcomes under other programs aiming to combine industry development with environmental goals have resulted in very high costs to the Australian community (Box 15).

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[114] Origin Energy, Electricity Pricing Inquiry, sub. 21, p. 5.
[115] Origin Energy, sub. 24, p. 4.
[116] Krugman 1993; Industry Commission 1996; Calcagno & Thompson 2004; QCA 2015d.
[117] QPC 2016a, p. 26.
[118] QCA 2015d.
[119] Nelson et al. 2012.

Box 15: Home Insulation Program

The Home Insulation Program (HIP) was one of a series of fiscal stimulus measures introduced by the Australian Government in 2009. The $2.7 billion program provided financial incentives for homeowners to install insulation. Prior to the program, around 70,000 homes had insulation retrofitted each year. At the peak of the program, this rose to 180,000 in a month. Around 8400 new companies entered the market to take advantage of the program.

The program was to have continued for two and a half years, but was terminated prematurely on 19 February 2010 following safety and compliance concerns and the death of four installers.

The government subsequently introduced several remediation programs, at an estimated cost of $425 million, involving safety inspections, removal and/or repair of insulation. It also provided industry with $56 million in adjustment assistance.

Four reviews of the program have been undertaken, and while some positive features were identified, all reviews found significant problems with program design and governance as well as wide-ranging non-compliance and fraud. Around 4000 potential cases of fraud were identified. The Royal Commission into the death of four installers found the program was a serious failure of public administration. It was poorly planned and implemented and had led to the avoidable death of four young men.

The Australian National Audit Office (ANAO) concluded that 'overall HIP has been a costly program for the outcomes achieved, including substantial remediation costs.' The ANAO also highlighted the four fatalities associated with installations and reputational and financial impacts to the insulation industry.

Source: ANAO 2010.

To be successful, industry development policies rely on governments being able to better judge investments than businesses or consumers. However, it is challenging for government to obtain necessary information to identify industries with a (potential) competitive advantage. For example, in the 1950s, the Japanese Government infamously decided to subsidise the petroleum and petrochemicals industry, while rejecting Sony's transistor technology venture because it was 'unpromising':

> *the available evidence — in the form of both econometric analyses and general observations — suggests that there is not a convincing link between governments targeting a particular industry and the performance of that industry. There were successes but there were also failures, and there were successes in spite of intervention.*[120]

In addition, industry development policies that promote a single technology risk damaging industry development and resulting in lower-quality or higher-priced services being offered to consumers.

Submissions noted that a feed-in tariff to promote industry development is inconsistent with the principle of neutrality and may result in overinvestment in solar PV with a consequential underinvestment in alternative carbon technologies and energy sources.[121]

Other submissions said that the market should be left to respond in the most efficient way to achieve a carbon reduction rather than support a particular technology;[122] and that the most effective market will be created by a 'technology-agnostic approach'.

Rapid innovation may mean that existing renewables technology may not be the dominant emissions reduction technology in the future. There is a risk that if policy frameworks are too

[120] Industry Commission 1990, p. 63.
[121] Australian Gas Networks, sub. 36, pp. 5–6.
[122] See, for example, Bruce Cooke, sub. 23, p. 1; Energex, sub. 33, p. 3; Ergon Energy Corporation, sub. 34, p. 20.

prescriptive and are unable to adapt to new technologies that may deliver better outcomes, they can stifle innovation and competition and 'lock in' existing technologies.[123]

6.1.2 Job creation and employment

Increasing employment is an important objective of state governments. It also features prominently as an objective of feed-in tariffs and renewable energy policy in Australia and overseas. Several submissions supported a view that government intervention, either through regulatory settings or subsidies, will ensure jobs are created in the renewable energy sector (including solar), leading to an increase in employment in Queensland.

Submissions noted that a feed-in tariff can:

- support employment and business in the future and give renewed incentive to employment and business;[124]
- transition employment to 'green' jobs and provide a 'buffer' for falling employment in fossil fuel industries.[125]

The University of Queensland's Global Change Institute noted that the benefits of a solar export industry are:

> *a strong vibrant industry with positive economic spin-offs, including the taking up of workers from other industries that may be in decline as well as providing tax revenue to the State. It would also be an enabler for the development of the energy storage industry as well.*[126]

Similarly, Sustainable Queensland[127] estimated that if feed-in tariffs could induce an additional 1700 MW of solar PV it would create 5908 jobs.

Can feed-in tariffs create jobs?

The solar PV industry is still a small contributor to employment in Queensland, with approximately 2350 direct full-time equivalent (FTE) positions in 2014–15.[128] At the peak of employment in 2011–12 there were 4470 FTE positions, which compares to total full-time employment in Queensland of 1.67 million people.[129]

There is a large body of international literature on the impact of renewable policy support, including feed-in tariffs for solar PV, on employment. However, few studies provide an independent assessment of employment outcomes, with many from advocacy bodies from both sides of the climate change debate. It is unsurprising that some studies estimate very large employment gains and others large losses.

Some studies have found employment gains from supporting renewable energy. For example, O'Sullivan et al.[130] estimated 261,500 jobs in the German renewable sector can be ascribed to the

[123] Frondel et al. 2009, p. 20.
[124] Mark Tranter, sub. 10, p. 3.
[125] Mark Tranter, sub. 10, p. 3; University of Queensland, Global Change Institute sub. 28, p. 10.
[126] University of Queensland, Global Change Institute, sub. 28, p. 10.
[127] Sustainable Queensland, sub. 32, p. 8.
[128] ABS 2016.
[129] In June 2012, Queensland full-time employed persons, seasonally adjusted was 1,667,700 while all employment (including full-time and part time / casual) was 2,328,000. ABS Catalogue 6202.0 Labour Force, Australia (ABS 2015a).
[130] O'Sullivan et al. 2014, p. 8.

impact of Germany's *Renewable Energy Sources Act 2000*. [131] Pollin et al. estimated that $100 billion of renewable investment could create two million jobs. [132]

Other studies suggest that once the costs of policy support were accounted for, net job creation cannot be counted as a benefit of renewables investment (Box 16). Taking account of adverse investment and crowding-out effects, both the Halle Institute for Economic Research (IWH) and RWI Essen find negligible employment impacts. The Bremer Energie Institut (BEI) concluded that despite initially positive impacts, the long-term employment effects of the promotion of wind and solar power systems are negative.[133] Alvarez concluded:

> *[T]he resources used to create "green jobs" must be obtained from elsewhere in the economy. Therefore, this type of policy tends to create not just a crowding-out effect but also a net destruction of capital insofar as the investment necessary must be subsidized to a great extent and this is carried out by absorbing or destroying capital from the rest of the economy.*
>
> *The money spent by the government cannot, once committed to "green jobs", be consumed or invested by private parties and therefore the jobs that would depend on such consumption and investment will disappear or not be created.*[134]

ESAA in its submission to the Electricity Price Inquiry stated:

> *The supposed job benefits of renewable subsidy schemes are a fallacy. This argument is based on only looking at the jobs created in the sector being subsidised and ignoring the lost jobs (including jobs that don't get created) elsewhere in the economy, because spending is diverted to the subsidised sector. Further, it should be noted that wind and solar projects have far lower operational jobs than the existing coal mines and generators.*[135]

Other international quantitative evidence suggests that the direct impact of feed-in tariffs on employment may be slightly positive or negative, but is very close to zero.[136]

A solar feed-in tariff could increase employment if it targeted factors that affect the level of unemployment in Queensland, and transitioned underemployed or long-term unemployed people into work. But there is no evidence that solar feed-in pricing or the characteristics of the solar PV employment market make feed-in tariffs a suitable vehicle for such a policy.

[131] BMU 2012, p. 7. A key feature of Germany's *Renewable Energy Sources Act 2000* is the requirement for utilities to accept and remunerate (through a feed-in tariff) the delivery of power from various renewable technology electricity into the grid.

[132] Pollen et al. 2008 in Gülen 2011.

[133] Frondel et al. 2009.

[134] Alvarez et al. 2009, p. 27.

[135] ESAA, Electricity Pricing Inquiry, sub. 46, p. 7.

[136] Frondel et al. 2009, p. 19: 'Numerous empirical studies have consistently shown the net employment balance to be zero or even negative in the long run, a consequence of the high opportunity cost of supporting renewable energy technologies.'

Box 16: Can policy support for renewable energy lead to net job creation?

The United Kingdom Energy Research Centre undertook a review of 84 studies that examined the impact of policy support for renewable energy on job creation. The studies drew on a range of techniques (case study, survey, input–output analysis and computable general equilibrium modelling) to examine impacts on employment.

The review found that many of the studies found positive impacts on employment, but this outcome was derived by assuming:

- jobs created by renewable energy investment are the total number of jobs added to the economy (that is, there is no opportunity cost from policy support); and
- renewable energy is more labour intensive compared to other sectors in the economy.

Of those studies that attempted to examine the net impact on employment, the results were mixed, with some indicating a positive impact and others negative. Results often rest critically on the assumptions made on the macro-economy. If the study assumed the economy has unemployed or underemployed resources, it was more likely to find a short-run increase in employment. But if the economy is close to full employment, then employment is unlikely to be affected and policy support can crowd out private sector investment and bid up the price of scarce resources.

Overall, the review found:

- Policy support for renewables can contribute to short-term job creation if investment in new power generation is needed, so long as the economy is experiencing an output gap, such as is the case during and shortly after recession.
- In the long term, 'job creation' is not a meaningful concept for renewable policy assessment. High labour intensity is not in itself a desirable quality, and 'green jobs' is not a particularly useful prism through which to view the benefits of renewable energy.
- What matters in the long term is overall economic efficiency, taking into account environmental externalities and the dynamics of technology development pathways.

In other words, the proper domain for the debate about the long-term role of renewable energy and energy efficiency is the wider framework of energy and environmental policy, not a narrow analysis of green job impacts.

Source: United Kingdom Energy Research Centre (UKERC) 2014.

Ultimately, any shift in resources to support employment in the solar PV sector as a result of government assistance will come at a cost to other sectors. If solar PV jobs are to be filled by workers who are employed in other industries, there is no change in aggregate employment in Queensland.

Even if a subsidised feed-in tariff could create additional jobs in the Queensland economy, it would likely come at a large cost to the community. For example, using a simple comparison under the SBS, if it is assumed that the SBS was the sole catalyst for all solar PV jobs in Queensland (4470 FTEs in 2011–12), then based on the estimated cost to electricity customers of $4.1 billion over the life of the scheme, this results in a cost of approximately $1 million per position.

On balance, while regulating feed-in tariffs for job creation may influence the pattern of employment, as any increases in jobs in the solar industry are likely offset by reduced employment in other sectors, it is unlikely that there will be a net increase in employment. In addition, feed-in tariffs funded through higher electricity prices are likely to have a dampening effect on economic activity (through higher input costs on businesses and industries) which may negatively impact on the overall level of employment.

Social benefits

Some submitters suggested that the government should regulate feed-in tariffs due to the social benefits from solar PV, although little specific evidence was provided. For example, Judy Whistler noted that there can be ideological and lifestyle benefits, such as the 'pleasure of using renewable energy' and Sustainable Queensland pointed to a more resilient energy supply protected from 'extreme weather events and acts of terrorism'.[137]

The QPC has not identified specific social benefits from solar PV that would warrant changes to solar export pricing. The Essential Services Commission, in its position paper on the value of distributed generation, was similarly unable to identify other public benefits from distributed generation, which includes solar PV.[138]

There may be intangible benefits from a 'feel-good effect' of directly helping the environment, or directly supplying your energy needs; however, these benefits are difficult to measure and quantify. As these benefits are private in nature, they are not a sufficient reason for government regulation or having non-solar consumers pay a higher electricity price.

As a government-mandated subsidy transfers income from the 'community at large' to solar PV owners — either through higher taxes, reductions in government expenditure, or higher electricity prices for non-solar users — a clear social benefit is required.[139] When assessed against the costs, any public intangible benefits would need to be very large to justify government intervention. In this case, the social costs are likely to outweigh any social benefits of solar PV.

6.2 Wholesale market impacts

The 'merit order effect' refers to changes in wholesale electricity prices due to a decrease in demand or an increase in supply of electricity.

Some submissions said that solar PV generation has lowered wholesale prices through the merit order effect and should be appropriately rewarded:

> *Solar generation at or near the location of demand reduces the demand for electricity from the wholesale market. This in turn translates into downward pressure on wholesale electricity prices. … Therefore, it is important to recognise, and furthermore remunerate, a value in recognition of the MOE that is provided by solar PV generators as a benefit to all other electricity consumers in the form of lower electricity prices.*[140]

The NEM wholesale electricity market operates on the basis of scheduled generators bidding for the right to be dispatched at a certain capacity for a bid price.

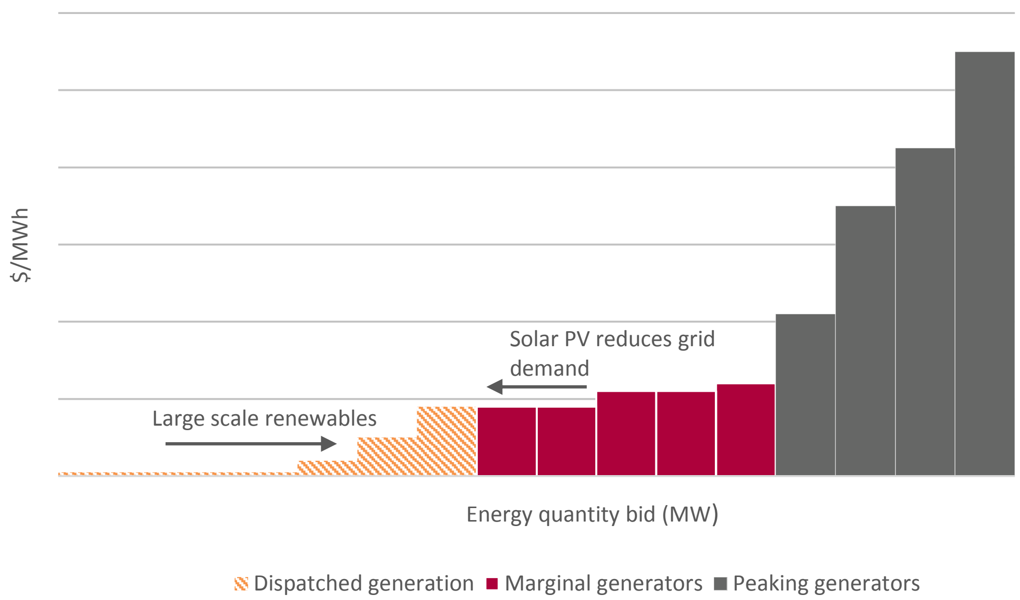
The Australian Energy Market Operator (AEMO) ranks those offers into merit order, from cheapest to most expensive and then 'dispatches' generators in this order until demand is met. The highest bid required to meet demand is known as the 'marginal bid' and the wholesale market price is set on the marginal bid; all generators that are dispatched are paid this amount. This process produces the lowest-cost dispatch solution required to meet the demand at that time.

In theory, solar PV generation can reduce the amount of electricity that retailers need to purchase from the wholesale market and thereby lower wholesale spot prices (Figure 32). Several studies have attempted to model the potential size of the merit order effect, and estimate it could be

[137] Judy Whistler, sub. 29, p. 2; Sustainable Queensland, sub. 32, p. 10.
[138] ESC 2015, p. 19.
[139] Centre for International Economics 2001, pp. 67–68.
[140] John Sheehan, sub. 20, pp. 16–17. Also see Don Willis, sub. DR6, p. 6.

substantial. The Melbourne Energy Institute[141] concluded that 4 GW of solar PV nationally could result in wholesale market price reductions in Queensland worth $35 million a year. At 10 GW of capacity, the impact could be in the order of $240 million per year. [142]

Figure 32: Merit order effect: Dispatch with renewable energy



Source: Based on Deloitte Access Economics 2015.

6.2.1 Should government regulate to pay solar PV owners if solar PV decreases wholesale prices?

Chapter 3 highlights that governments sometimes intervene in markets to address externalities (such as pollution). That said, not all third party effects are externalities (Box 17). Consumers and businesses have impacts on others every day, in varied ways. In a competitive market without subsidies, consumer or business behaviour that changes relative prices does not distort resource allocation and does not result in inefficiencies. This contrasts with pollution, for example, where the private costs diverge from the social costs.

[141] Melbourne Energy Institute 2013, p. 44.
[142] For other Australian and international studies of the merit order effect see SKM MMA 2011; Gouzerh et al. 2013.

Box 17: Externalities versus third party impacts

Not all third party effects are policy relevant. For example, assume a fishing business operates in a coastal area and the price of fish falls under four different scenarios. All scenarios reduce the price of fish by $10 per kilogram:

- Pollution is released from factories into waterways, reducing the quality of fish.
- A second fishing business enters the market, increasing supply of fish to customers.
- Local fishermen start selling fish to local restaurants.
- Consumers demand less fish.

All scenarios have the same impact on prices, but only the first provides a case for government to intervene in pricing, since the private costs of factories polluting are not aligned to the social cost of that pollution on the wider community. The other scenarios maximise social welfare. If governments required local restaurants to pay local fishermen a levy for reducing prices on top of the price they are paid for fish, or pay consumers for demanding less fish, the community would be worse off.

In the same way, governments do not require an auction winner to compensate bidders that withdraw from a property auction and thus lower the final price paid. Nor would they require a washing machine manufacturer to compensate a laundromat for reducing demand. Such impacts are reflected in market prices, and while they may involve transfers across market participants, they do not reduce welfare (and in most cases actually improve it).

The distinction between externalities and third-party effects is central to policymaking. Pigou's 1924 seminal work recommended the application of corrective taxes or subsidies to address externalities. He also clearly noted that not all third party effects create a divergence between private and social costs and:

> *that in such cases, social welfare maximisation requires that such third-party effects occur. Pecuniary [Impacts] are an integral part of the market mechanism.*
>
> *From a policy standpoint, efficiency requires the clear definition and protection of property rights over the ownership of resources, but efficiency also requires that no property rights be assigned over the value of those resources. In other words, for efficiency … [negative] externalities should be prevented but pecuniary [impacts] must be allowed.* [143]

The same merit order impact can occur when a new generator enters the market or consumers reduce demand. If retailers or electricity customers were required to compensate solar PV owners if solar PV reduces wholesale spot prices, the outcome would be:

- All other generators (renewable and thermal) and consumers would be eligible for such compensation when they affect the merit order.
- Solar PV owners would have to pay retailers and electricity customers if solar PV is associated with an increase in wholesale market prices.

As a result, there is no case to increase feed-in tariffs to pay solar PV owners for any impact on wholesale market prices. That said, even if there were a case for government to intervene, it is unlikely that a merit order effect induced through government mandated payments can benefit the Queensland community.

Actual quantification of the merit order effect is limited due to the difficulty of isolating solar PV generation from other demand-side management measures. Such an assessment would need to account for the full impact of solar PV on the wholesale market over time. For example, the intermittent nature of solar PV means that while it may reduce spot prices when generating, it can

[143] Holcombe & Sobel 2001.

also increase them when demand spikes, for example, due to cloud cover. An increase in volatility of the spot market will flow through to higher contract prices. In addition, the ability to sustain a merit order effect over the longer term is uncertain. Where such an effect leads to plant withdrawal (particularly base load and 'mid-merit-order' plant) it may increase wholesale prices in the longer term.

If a merit order effect occurs naturally in the market, then to the extent there is competition in the retail market, lower wholesale prices would be passed through to consumers and the Queensland community would be better off:

> *If a merit order effect occurred due to natural market disruption events such as the entry of a new renewable or low emission technology with lower marginal running costs and lower total costs than incumbent generators, it would produce an unambiguous improvement in welfare.*[144]

But, because renewable energy suppliers (including solar PV) are supported by the Renewable Energy Target (RET) scheme and SBS, which are paid for by electricity customers, the overall price impact is not necessarily positive. The reduction in wholesale prices would need to more than offset the increase in retail prices for there to be an overall price effect.

Conceptually, if it was possible for electricity customers to subsidise higher cost producers such as solar PV through feed-in tariffs and it would result in lower overall electricity prices, then the government should mandate a subsidy to meet all production. But, as noted by Felder[145], under such a scenario, wholesale prices would be near zero, yet electricity prices would be higher to cover the additional costs of renewable technologies.

Some international studies, mainly from Germany, and some Australian analyses have concluded there is an overall price reduction from the merit order effect.[146] However, evidence for Queensland suggest the impact is, at best, zero to negative. For example, SKM[147] estimated that the RET will reduce wholesale prices in Queensland by $4.76/MWh from 2016–20, but once the cost of certificates are paid for in the retail price, overall consumers will pay $3.62/MWh more for electricity. A similar finding was made in the 2014 review of the RET:

> *Analyses suggest that, overall, the RET is exerting some downward pressure on wholesale electricity prices. This is not surprising given that the RET is increasing the supply of electricity when electricity demand has been falling. Artificially low wholesale electricity prices can distort investment decisions in the electricity market and are unlikely to be sustained in the long term. Over time, all other things being equal, wholesale electricity prices could be expected to rise to better reflect the cost of generating electricity.*
>
> *The direct costs of the RET currently increase retail electricity bills for households by around four per cent, but modelling suggests that the net impact of the RET over time is relatively small. The impact on retail electricity prices for emissions-intensive trade-exposed businesses and other businesses is significantly greater. The RET does not generate an increase in wealth in the economy, but leads to a transfer of wealth among participants in the electricity market.* [148]

This outcome is also consistent with modelling conducted by ACIL Allen for this inquiry which found that a subsidised feed-in tariff would reduce wholesale market prices, but this is generally more than offset by an increase in retail prices (Chapter 7).

Overall, the evidence does not support the government requiring consumers to pay a higher feed-in tariff if solar PV reduces wholesale prices. Even where a merit order effect exists, it most likely

[144] Nelson et al. 2012, p. 17.
[145] Nelson et al. 2012, p. 17.
[146] See for example, Sensfuß, Ragwitz & Genoese 2008.
[147] SKM 2013.
[148] Warburton et al. 2014, p. i.

represents a transfer from existing generators, rather than a genuine creation of wealth. And once the costs of providing the price impact are accounted for, including direct costs and indirect losses, the community may be worse off overall.

6.3 Electricity generation cost impacts

In addition to the merit order effect, some stakeholders indicated that there are benefits from solar PV on electricity generation costs. For example, the Australian Solar Council stated that a solar feed-in tariff should include a component for avoiding investment in generation capacity and the 'provision of energy for decades at a fixed price'. [149]

In relation to generation costs, the Queensland community is best served when resources are directed towards generating electricity at least-cost. Higher than necessary generation costs impact on both households and businesses who have to devote more resources to paying for electricity than otherwise. For the community to be better off in terms of generation costs, solar PV would need to reduce the total cost of electricity generation.

The impact of solar PV on generation costs in Queensland can be examined by estimating the cost of electricity generation for different technologies.

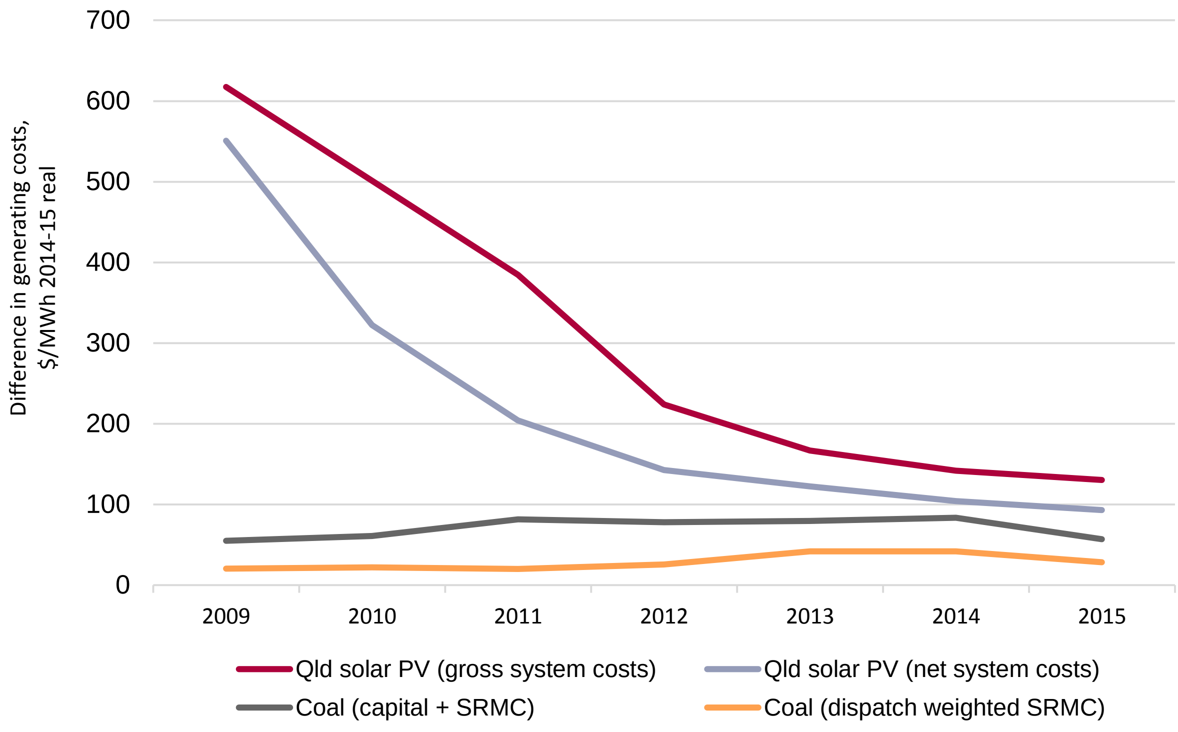
Investment in small-scale solar PV has raised the cost of producing electricity in Queensland. In 2009, the fully capitalised and unsubsidised cost of producing energy from solar was $617–$821/MWh (in real 2014–15 dollars), depending on the cost of capital assumed (see the notes to Figure 33). The cost of producing energy from Queensland coal-fired generation was $55/MWh.

The cost performance of solar has improved markedly with rapidly declining prices. In 2015, the stock of installed solar PV is estimated to generate electricity at an unsubsidised cost of $130–$206/MWh, compared to coal at $57/MWh.

Basing cost comparisons on net solar system costs (gross system costs less solar subsidies), results in a subsidised cost of electricity generation of $93–$105/MWh in 2015. The subsidised cost of solar energy generation is not quite double the cost of coal generation. Where solar PV reduces emissions and this results in environmental benefits, the subsidised cost comparisons provide a better basis for comparing the relative costs of solar and coal generation.

[149] Australian Solar Council, sub. DR23, p. 2.

Figure 33: Relative efficiency of Queensland coal and solar PV in generating electricity per MWh

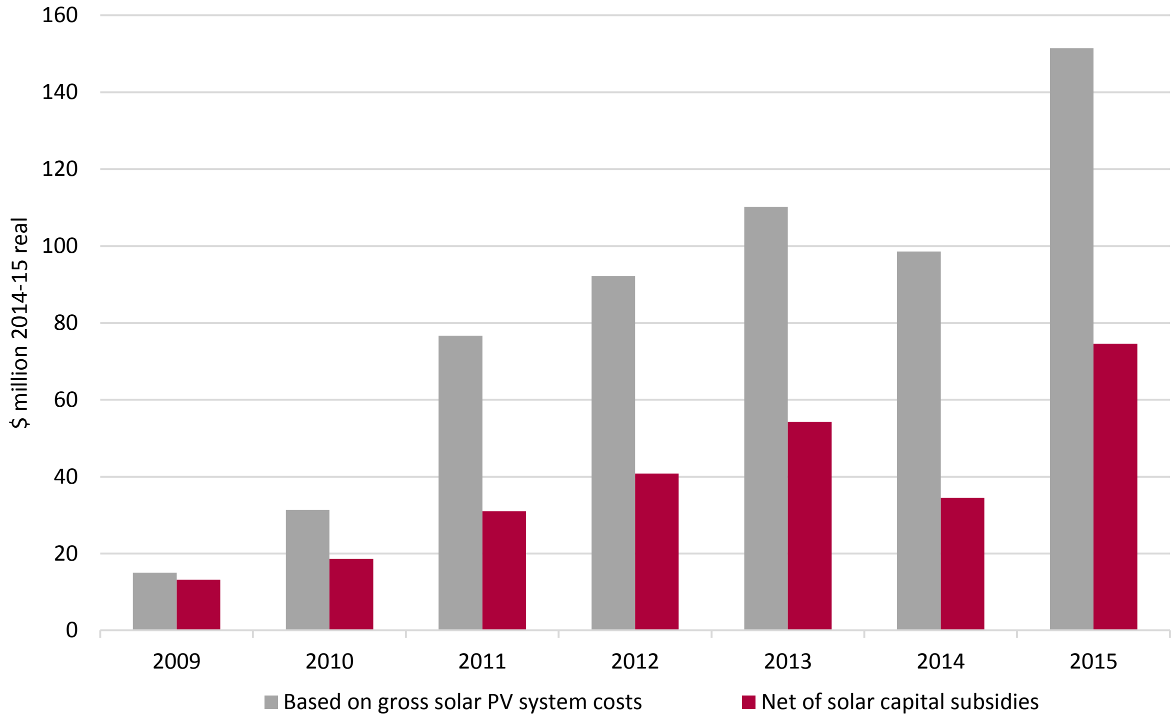


Notes: Queensland solar estimates are shown both gross and net of solar subsidies. If solar PV achieves environmental benefits, then the cost comparisons based on net costs are more relevant as they are a better indicator of the relative costs of energy generation taking into account environmental impacts. The solar cost estimates are based on installed average system size estimates increasing from an average of 1.5 kW to 3.1 kW over the period. The cost of capital for the solar estimates is based on a 3-year fixed home loan rate. If a higher cost of capital is used at 7.3 per cent real, then the solar estimates are higher by between 25 and 58 per cent, depending on the year. Coal short-run marginal cost (SRMC) estimates are based on estimates of the SRMC of coal generation actually displaced by solar. This includes coal fired generation from Colinsville, Gladstone, Swanbank B and Swanbank E, and Tarong generators. The value of the actual capital consumed in coal generation is unknown and has been estimated by examining the capital cost of a new entrant supercritical coal generator. The estimates are broadly consistent with Levelised Cost of Energy (LCOE) estimates produced in other studies (for example, see AEMO (2014) and Lazard (2015) (and earlier Lazard versions)).

Source: ACIL Allen 2016 and QPC calculations.

Based on gross solar PV system costs, the increase in energy generation costs was $151 million in 2015 (Figure 34). Excluding the subsidy, the increase in generation costs is lower at $75 million in 2015. Solar PV has become more cost-competitive over the period on a per megawatt hour basis, but the rapid increase in the volume of solar generation has driven energy costs higher.

Figure 34: Increase in Queensland energy costs from the installation of solar PV



Notes: The estimates of the cost of generating electricity from solar PV use a cost of capital set equal to the 3-year fixed home loan rate (which reduces from 4.3 to 2.4 per cent real over the period). If a higher cost of capital is used at 10 per cent nominal, or 7.3 per cent real, then the estimate of the impact of solar PV on generation costs in 2015 is increased to $308 million (based on gross system costs) and $181 million (based on system costs net of solar subsidies).

Source: ACIL Allen 2016 and QPC calculations.

6.4 Network impacts

The increasing penetration of solar PV has impacts on network infrastructure. There may be benefits, such as deferral of network augmentation, but also costs, such as managing reverse power flows.

6.4.1 When and how solar PV can provide network benefits

Customers with solar PV can reduce the use of networks by:

- reducing consumption by generating some of their energy requirements from solar PV; and
- exporting surplus energy, reducing the need to transport energy from large-scale generators through the network.

Over time, this may mitigate the need to invest in upgrading the network. The extent to which solar PV will give rise to benefits depends on its ability to defer or avoid network augmentation thereby improving network efficiency (Box 18).

Box 18: When is an investment delay beneficial?

Delaying investment may or may not result in benefits depending on the context of the investment, for example, what conditions drive the business to delay investment.

If a customer reduces their demand for a product from a company, then that company may delay an investment which would increase its productive capacity, but it cannot be said that the company is better off because of lower demand for its product (Case A below). Companies have an objective to maximise profits, not delay investment.

It may be in the interests of the firm to delay investment in the presence of uncertainty with respect to, for example, external market conditions (Case B below). The resolution or reduction of uncertainty has a value because capital investments are a sunk cost.

Changes, either initiated by the firm or externally driven, which increase the efficient use of existing assets will provide financial benefits to the firm (Case C below).

Typology of circumstances leading to delayed investment

	Case A	*Case B*	*Case C*
Description	Change in a firm's external environment which reduces the expected value of investment below the firm's required hurdle rate of return	Change in a firm's external environment which raise market uncertainty so that there is less confidence that the expected values of investment will eventuate	Changes increase the efficiency of which existing assets are utilised, thereby delaying the need for new investment
Examples	Changes which reduce demand for the firm's products or raise the cost of investment, including normal competitive market effects	Uncertain impacts of rapid technological change	Tariff reforms (e.g. time-of-use charging) that help smooth demand profiles
Response	Investment delayed until the point where the required expected value of investment is re-established, or funds flow to alternative uses	Investment is delayed until new information reduces uncertainty and the required expected value of investment	Investment delayed until such time as capacity constraints, or other changes, warrant new investment
Benefits of delay	No financial benefits to the firm. Investment delay is a response to negative impacts on the firm (e.g. loss in revenues)	Investment delay is a rational response to increased uncertainty. However, it does not involve profits beyond normal rates of return	Improved productivity provides financial benefits to the firm. In a regulated setting, benefits are shared with consumers through reductions in allowable revenues (prices)

For solar PV to induce beneficial investment delay it must induce Case C — by improving network efficiency because it reduces peak demand, thereby delaying capital investment.

Peak demand is a key driver of investment in electricity networks as it determines the capacity that a network must be built to accommodate. Peak demand describes the maximum power delivered through an electricity network at any given point over a period of time. In Queensland, it typically occurs in the early evening in residential areas and during the day in commercial and industrial areas. In aggregate, the system peak demand tends to occur during summer in the late afternoon or early evening.

For solar PV to reduce network expenditure it must not just reduce use of the network, but reduce the peak demand on network assets that are capacity constrained.

There are examples of solar PV being used to defer network investment (see Box 19).

Box 19: Ergon Energy case study: avoiding network augmentation using solar PV

In 2014, Ergon Energy identified two zone substations in South Mackay in which peak demand during weekdays was growing and heading towards the maximum capacity. However, the networks were relatively underutilised at night and on weekends. Upgrading the substations and associated transformers and conductors was going to be significantly expensive.

Ergon Energy launched a demand management initiative that, among other things, financially incentivised commercial customers to install PV systems above 10 kVA to reduce the day-time demand on the grid. The project only incentivised non-exporting systems as encouraging export may have created a new issue of high voltage, and commercial areas are not as prone to the third- or fourth-day peak as residential areas.

Such initiatives show promise in terms of a network benefit of PV in a small number of specific circumstances, generally there is not sufficient evidence to show that exporting PV will defer upgrades as a result of the peak demand reduction created by exported electricity, or even PV more generally.

Source: Ergon Energy Corporation, sub. 34, p. 22.

However, the impact of solar PV is dependent on a variety of factors such as location, topology of the network, penetration level and load characteristics. Benefits and costs are highly variable and must be assessed on a case-by-case basis (see, for example, the Clean Energy Council's report valuing the impact of small-scale generation on networks — Box 20). As noted by the Australian Energy Council:

> *The impact on network costs of small scale PV varies with a range of factors including location, feeder characteristics and local penetration. Analysis by EY for the Clean Energy Council shows that for sample feeder types, the impact on network costs can change from a benefit at low penetration rates to a cost at high penetration rates. It also shows that the impact can be highly variable between feeders. This will inevitably make the attribution of a single 'true value' incorrect, and it is prohibitively complex to calculate for each individual installation.*[150]

[150] AEC, sub. DR9, p. 3.

Box 20: Clean Energy Council: Calculating the value of small-scale generation to networks

In 2015, the Clean Energy Council released a report prepared by Ernst and Young (EY) – *Calculating the value of small-scale generation to networks*. EY was tasked with examining the costs and benefits of distributed energy resources (DERs) to networks. The aim of the report was to assist network businesses to evaluate the costs and benefits of DERs and encourage efficient investment. EY was not tasked with examining how any net benefit should or could be captured through pricing.

The report found that while there was broad agreement on the potential costs and benefits of DERs on the network, there was:

- little agreement on the best way to quantify those costs and benefits; and
- widespread acknowledgement that any quantification would require high analytical granularity, and that task was a challenge.

The table below sets out the potential costs and benefits of DERs to networks identified in the report.

Potential costs and benefits to networks from small-scale generation

Value category	*Financial impact on network*	*Cost or benefit*
Network augmentation	High	Either
Network support	High	Either
Voltage regulation	Moderate	Either
Power quality issues	Moderate	Either
Reassessment of fault level co-ordination	Low	Cost
Network reliability	Currently low, but potentially significant	Either
Islanding capability	Currently not applicable, but potentially significant	Benefit

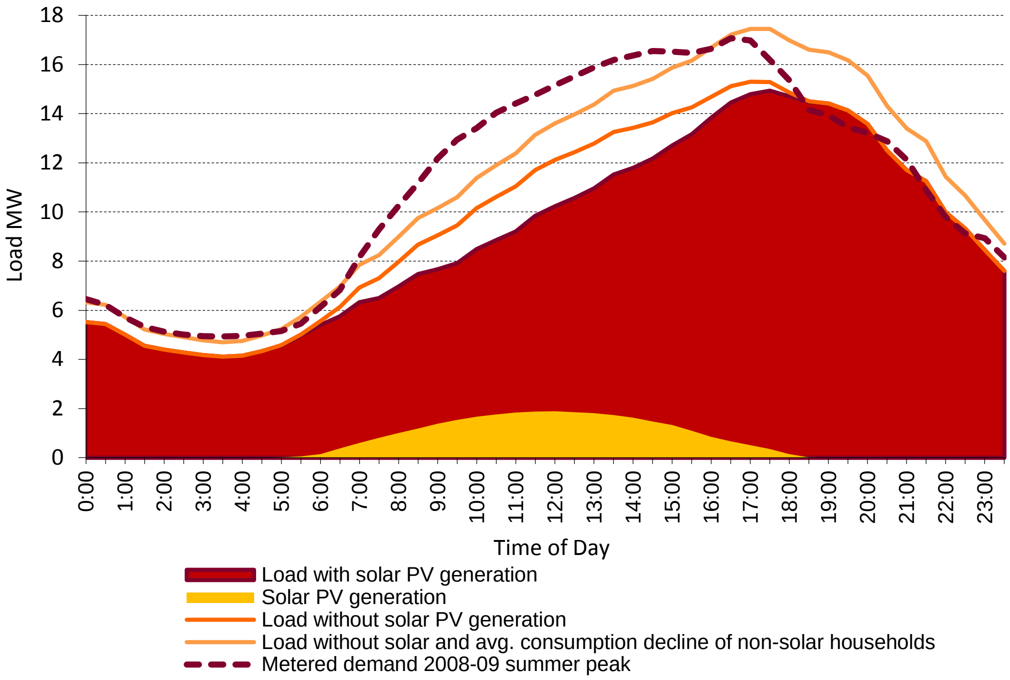
EY sought real-world applications from network businesses to apply the framework, but none were identified. Energex was able to supply a project that had been cancelled due to changes in the security standard and load forecast. Energex identified a radial 33 kV feeder in SEQ where augmentation would be needed by 2015–16. The report concluded that if solar PV penetration could be raised from 28 per cent to 60 per cent immediately it would reduce peak loading sufficient to delay the network augmentation by two years. This delay would equate to $2.2 million of savings in NPV terms.

Source: CEC 2015c.

Such an analysis is further complicated by difficulties in isolating the impact of solar PV versus other factors on the network. For instance, since 2009, average residential consumption has declined for both solar and non-solar households. The rate of decline has been greater for non-solar households falling roughly 20 per cent between June 2009 and June 2015. Energex data also indicates that solar households have used more electricity than non-solar households from mid-2014.

Depending on how the systemwide reduction in consumption has reduced the load profile on individual network assets, and possibly contributed to changes in the shape of the load profile, the magnitude of the systemwide reduction might mean that falling average consumption has contributed significantly more to reducing maximum demand than contributions from solar PV. Figure 35 uses the Jindalee feeder to illustrate these impacts (Appendix G provides further detail).

Figure 35: Impact of solar and non-solar customers: Illustration using Jindalee feeder



Notes: The decline in average consumption of non-solar households is assumed to affect the load profile proportionally across the 24-hour period.

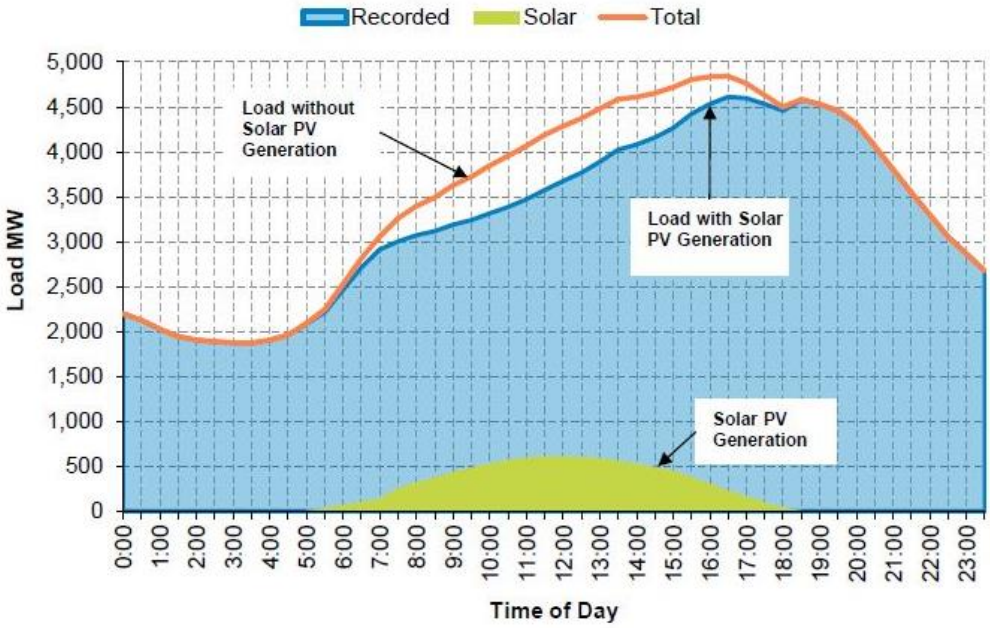
Source: Energex data; QPC calculations.

Therefore, it might be argued that the fall in average consumption of non-solar households provides a case for financial compensation similar to the case argued for solar PV. However, as with solar PV, the reduction would have to occur on assets that face capacity constraints not too far into the future, and contribute to peak reduction (for solar this means the peak must occur during generating hours). More importantly, solar and non-solar households already receive financial benefits where network costs are avoided. AER regulatory determinations take account of the need for operating and capital expenditure. Where that need is lower, the AER 'allows' a lower level of revenue to be generated by DNSPs, which means lower prices.

6.4.2 Does solar PV reduce network expenditure?

There is some evidence that solar PV generation may reduce the peak demand at the overall system level. Energex reported that at the time of the summer system peak demand on 5 March 2015, solar PV generation reduced the peak by 230 MW (Figure 36). Notwithstanding this, it is unlikely that any shaving of the system peak will translate into savings at least in the medium term.

Figure 36: Solar PV impact on Energex system demand, 5 March 2015



Source: Energex 2015b, p. 37.

First, few network augmentations are proposed in the regulatory period 2015–20 (largely due to changes in security standards) and greater general entry of solar PV is unlikely to modify this:

> *This essentially means that there is expected to be only a limited number of constraints that need to be addressed in the current regulatory control period. A broad based Feed-in Tariff (FIT) does not remove these constraints as it there is no guarantee that customers on the constrained feeder will respond in a way that addresses the constraint…* [151]

> *..cost savings from embedded generation connecting … where there is sufficient spare capacity to meet current and forecast future electricity demand are likely to be low or zero, because the value of any potential deferral or down-sizing of future network investment is relatively low. Costs may even increase if the additional generation output results in bi-directional flows and increases fault levels.*[152]

In those parts of the network where there is no planned augmentation or no deferral of augmentation the value to the network of solar PV is zero (or negative).

Second, peak demand at the local zone substations, feeders and low voltage network remain largely unchanged. Evidence from Energex and Ergon Energy (Network) suggests that in the majority of cases, solar PV has had minimal impact on peak demand at zone substations and feeders that supply residential customers:

> *Ergon Energy designs and constructs our networks to meet the highest or critical peak, forecast demand in coming years. The highest forecast demand occurs on 70% of Ergon Energy's feeders in the evening. As PV systems are not generating at that time, they deliver no network benefit on those feeders.* [153]

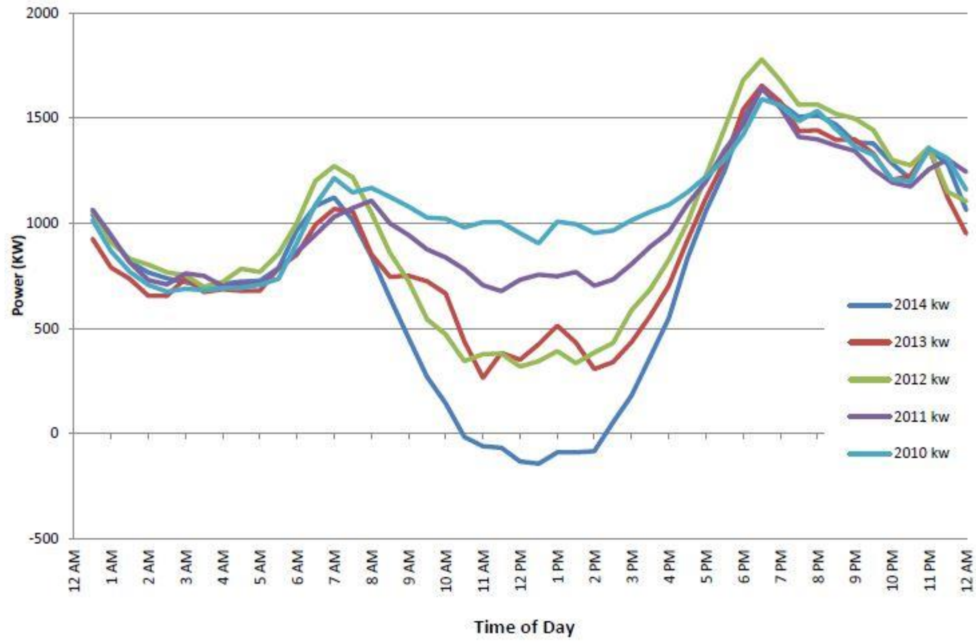
> *The increase in solar PVs has provided limited benefit to Energex's network as only a small portion of the solar generation occurs during the domestic peak demand time. The high penetration of solar*

[151] Ergon Energy Corporation, sub. 34, p. 4.
[152] Australian Energy Market Commission 2015c, p. 22.
[153] Ergon Energy Corporation, sub. 34, p. 22.

PV has also reduced energy throughput (kWh) delivered through the grid reducing network utilisation.[154]

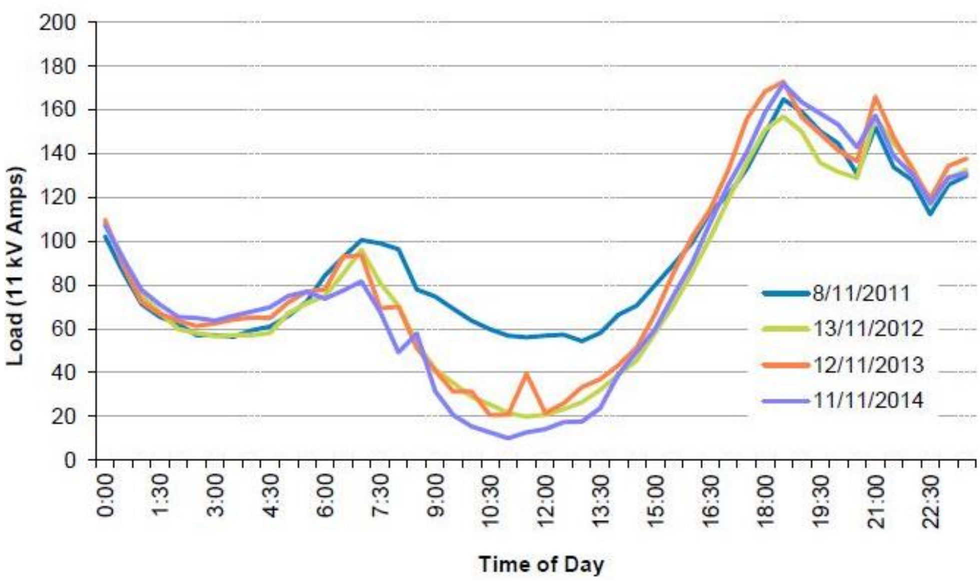
Figure 37 and Figure 38 show that even though solar PV has hollowed out demand during the middle of the day, peak demand, which occurs in the evening when the solar PV panels are no longer in operation, has remained relatively unchanged.

Figure 37: Burrum Head feeder change 2010–14



Note: Burrum Head is a seaside village in the Hervey Bay area of east Queensland.
Source: Ergon Energy Corporation 2015b, p. 26.

Figure 38: Currimundi feeder change 2011–14



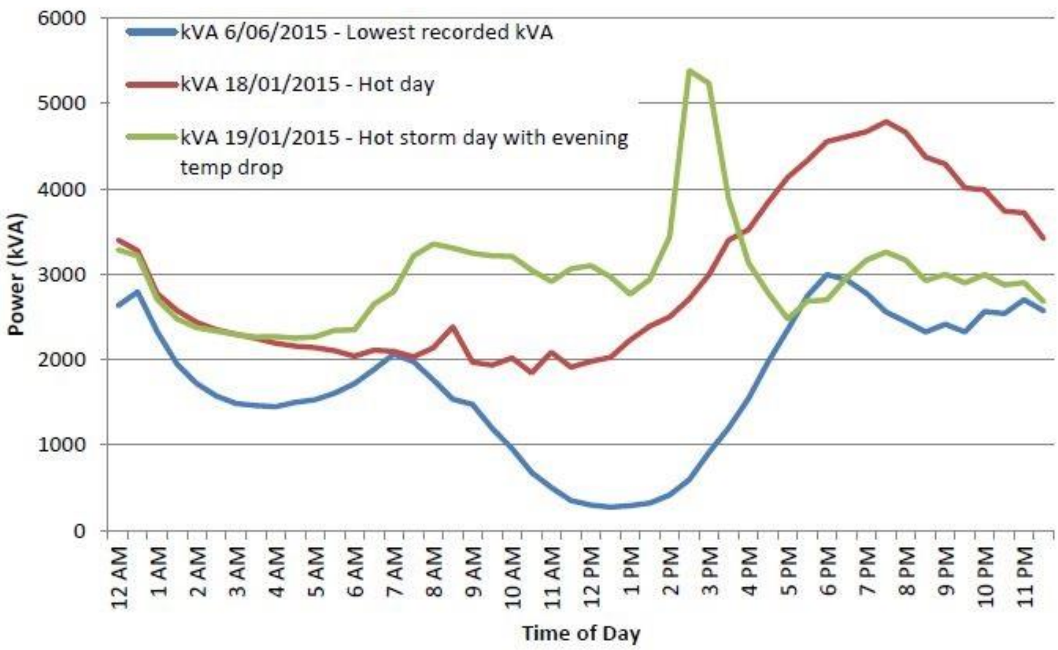
Note: Currimundi is a suburb in the urban centre of Caloundra on Queensland's Sunshine Coast.
Source: Energex 2015b p. 143.

[154] Energex, sub. 33, p. 3.

Any cost savings to the network will depend on the certainty of solar PV generation. Solar PV can defer network augmentation only if it can be relied upon to generate when the network is constrained in times of peak demand. Figure 39 demonstrates the impact of intermittent solar generation, where it can mask load growth that only becomes apparent when an unexpected event (such as, sudden cloud cover from impending storm event) causes PV systems to stop generating. The net result was a peak demand event that occurred on the feeder in the early afternoon which was higher than the usual evening peak. Ergon Energy (Network) noted:

> *The intermittency of PV generation means network planners cannot rely on it to lower critical peaks. As a result, network capacity needs to be designed and constructed to the same level, whether there is high PV penetration or no PV at all.* [155]

Figure 39: Dundowran feeder loading



Source: Ergon Energy Corporation 2015b, p. 27.

Note: Dundowran is in the Hervey Bay coastal area in southern Queensland.

Appendix G examines network data to assess the impact of solar PV. Key findings from the analysis are:

- Peak demand for most zone substations occurs when solar PV is not generating

For zone substations, 71 per cent of rural and remote zone substations on Ergon Energy's network had a peak that occurs between the hours of 6 pm and 6 am. The proportion for regional centre substations is lower at 38 per cent with the greater influence of commercial and industrial activities that have daytime peaks.

For Energex's network, the proportion of domestic zone substations with peaks after 6 pm is 74 per cent, and 21 per cent for 'other' substations which includes industrial, mixed industrial and mixed domestic substations. The zone substation load profiles and peaking times suggest that the above load profiles for Burrum Head and Currimundi feeders are representative of a large proportion of feeders in Queensland.

[155] Ergon Energy Corporation, sub. 34, p. 22.

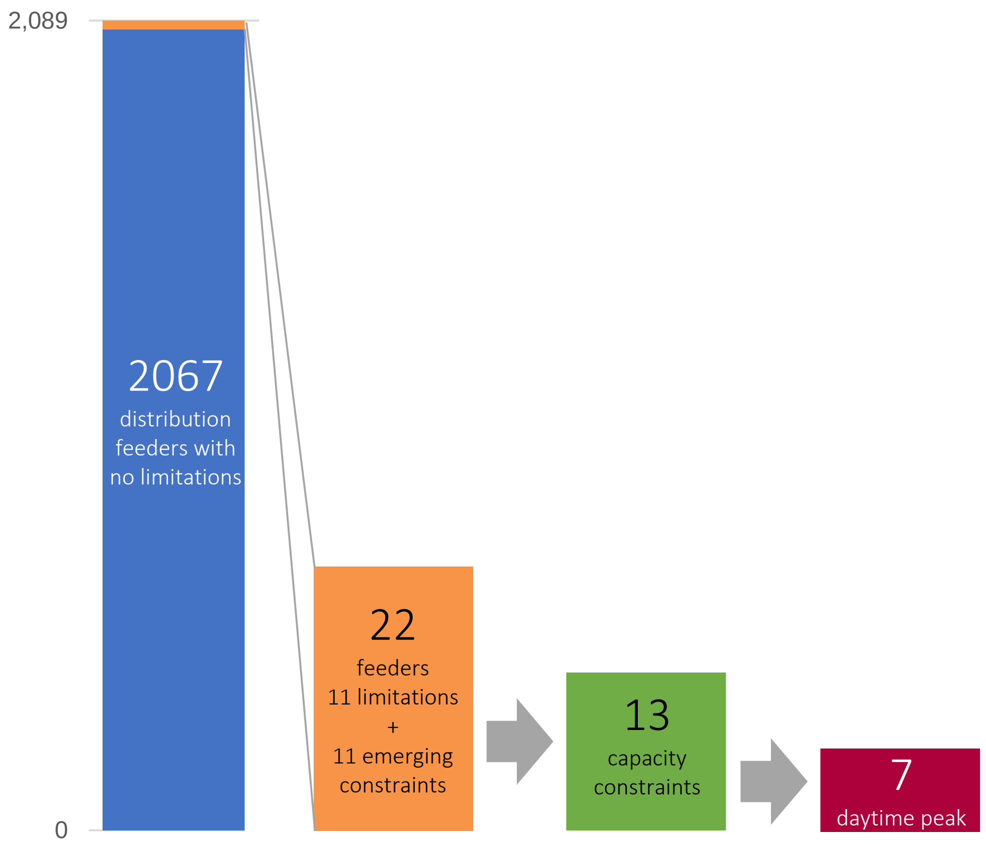
Of Energex's domestic zone substations, 74 per cent experienced a peak reduction of less than one per cent in 2014–15 due to solar generation. For Energex's industrial, mixed industrial and mixed domestic substations, 36 per cent experienced a peak reduction of less than one per cent. Of Energex's constrained domestic zone substations, only two had a peak reduction of greater than one per cent.

- Few constraints are arising on the network due to factors unrelated to solar PV

As well as regulatory standards, factors such as past investment, subdued economic growth and a trend in declining overall average consumption mean few network limitations (constraints) are arising. As there are also few capacity constraints going forward, there is little ability for solar PV to defer network expenditure.

For Energex's 11 kV distribution feeders, of its 2089 feeders there are only two with identified capacity constraints with a daytime peak, plus an additional five feeders with daytime peaks being monitored for emerging capacity constraints (Figure 40). Of these five feeders, analysis indicates that the deferral potential of installed solar capacity is: two years for one feeder; one year for two feeders; and less than a year for the other two feeders.

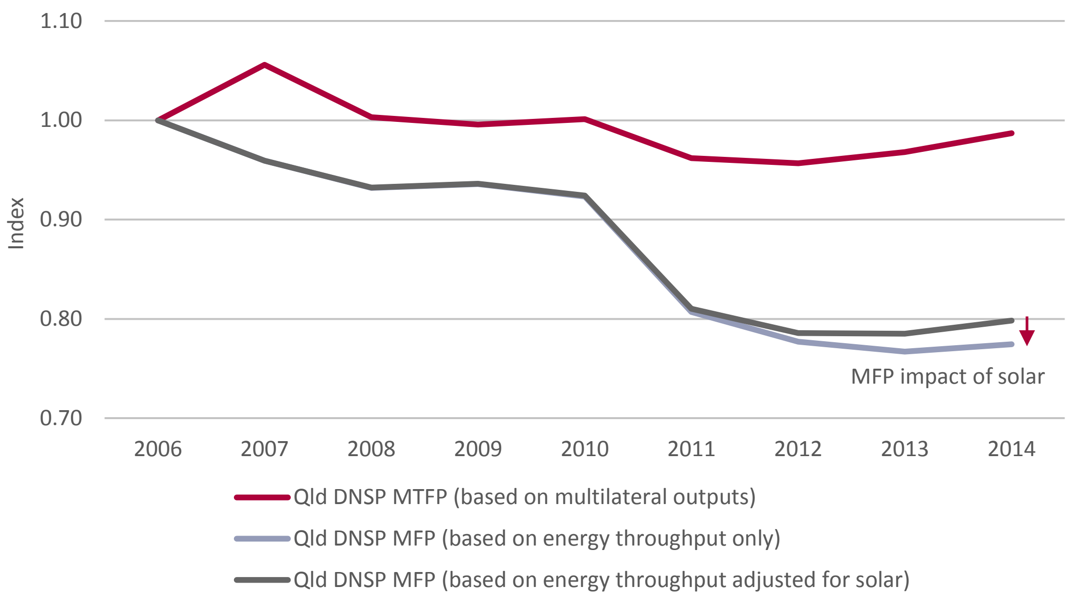
Figure 40: Energex forecast limitations on 11 kV distribution feeders, 2015–16 to 2019–20



Source: Energex 2015b; Energex unpublished information.

Appendix H examines the impact of solar PV on the productivity of network businesses. In summary, because solar PV has reduced network outputs, while not significantly altering network inputs, the result is a negative impact on multifactor productivity (MFP) (Figure 41). The negative impact is relatively modest because the volume of electricity generated by solar PV is small compared to the volume delivered to households from the grid. However, as solar generation increases over time the negative impact on MFP will grow unless solar has positive impacts on network costs (inputs), for example, through battery storage reducing the network peak.

Figure 41: Queensland DNSP productivity with and without solar for 2006–14



Notes: The solar adjustment includes only solar generated electricity used on premises. It excludes solar electricity that is exported to the grid. The output index used to calculate MFP with and without solar is based on energy delivered only. In the AER benchmarking of DNSP productivity, the output index is specified more broadly to include: ratcheted maximum demand; customer numbers; circuit lengths; and reliability. Since 2010, growth in these additional outputs has either been positive or flat, whereas energy delivered has declined. Growth in MFP based on the broader specification of outputs has been flat since 2006 (see Appendix H), but solar detracts from MFP growth in the same way as illustrated above.

Source: Economic Insights 2015a; ACIL Allen Consulting 2015; QPC calculations.

The majority of solar installations continue to be connected to the grid. Solar exports are only possible through the use of the network. Apart from providing the connection for export of surplus generation, the grid also provides connected solar customers with continuous supply and the power quality required for home appliances such as air-conditioners, pool pumps and computers.

There are costs of solar PV to network businesses, and potentially other market participants and consumers. Integration of embedded generation requires effective management of a range of technical issues such as voltage regulation, power quality, network protection and safety and fault level management:

> *The increase in solar also presents a number of challenges for Energex in terms of the safe and efficient management of the network. These challenges include maintaining electricity supply quality for customers and managing the effects of reverse power flows; both of which impact the cost of providing network services. In addition, Energex has experienced costs relating to application assessments and administration, meter connection and safety assessment and voltage complaint response for solar PV installations.* [156]

The cost to integrate solar varies depending on penetration level, network type, network loading and location and size of solar PV.

[156] Energex, sub. 33, p. 8.

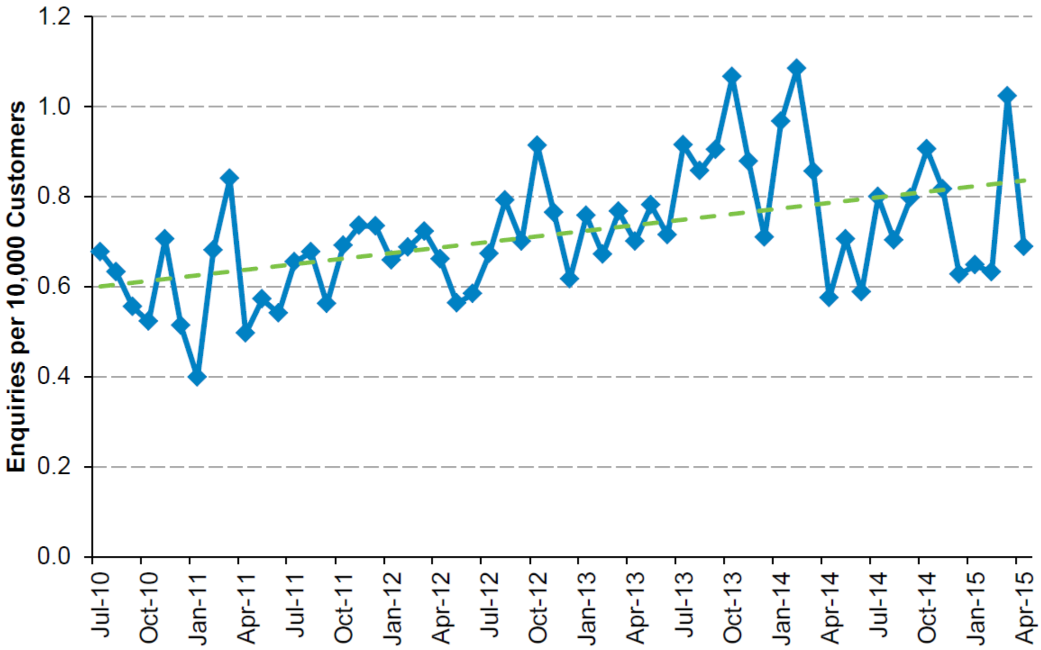
As noted by the Clean Energy Council (CEC), integrating new generation sources into distribution networks in a cost-reflective manner is a significant challenge:

> *At small penetrations of DERs [distributed energy resources] say, <10% of customers), the impact of DERs on the distribution network may be negligible. However, larger penetrations of DERs can significantly alter the power flows in the network, leading to changes in the costs of operating and managing the network, as carried out by a Distribution Network Service Provider (DNSP). The overall change to this cost may increase or decrease, depending on the situation.* [157]

The ENA noted the up-front costs of connecting solar PV, as well as costs associated with managing power quality and security. It highlighted a Massachusetts Institute of Technology study which identified rising costs for distribution networks as solar PV penetration grows. [158]

In the last 12 months, Energex has reported: a 26 per cent increase in transformers with high solar penetration; feeders with very little load during the day; or in a number of cases, feeders experiencing reverse flows.[159] This trend is understood to be causing some power quality issues as demonstrated in the increasing number of complaints shown in Figure 42 below.

Figure 42: Energex power quality enquiries



Source: Energex 2015b, p. 129.

In its recent determination, the AER has provided Energex and Ergon Energy (Network) a capex allowance of $24 million[160] and $26.4 million[161] respectively to address power quality issues relating to solar installations. Additional operating expenditure to address solar PV issues amounts to $11 million and $12 million respectively. These costs are passed on to all customers, including non-solar customers.

[157] Clean Energy Council 2015c, p. 6.
[158] ENA, sub. DR20, pp. 2–3.
[159] Energex 2015b, p. 143.
[160] AER 2015a.
[161] AER 2015b.

Overall, the evidence available indicates the following:

- Solar PV has the potential to defer network expenditure, but this impact is highly dependent on a number of prerequisite location, time and load profile conditions; and
- Analysis of network data suggests that solar PV has not resulted in material savings to networks to date, and to the extent they arise over the next five years, they will not offset the more than $73 million in costs to integrate solar PV into the network.

6.4.3 Is a feed-in tariff an appropriate tool to target potential network benefits?

As highlighted in section 6.4.1, there will be specific cases where solar PV can reduce network expenditure, particularly in a constrained environment. Moreover, it is possible that going forward solar PV combined with battery storage and time-of-export pricing could alter the impact on peak demand. If solar PV owners use solar PV to charge batteries during the day and then draw on stored energy during the evening peak, it could moderate the peak, at least on some parts of the network.

But even in cases where augmentation can be avoided or deferred, a broad-based feed-in tariff, with a component for network benefits, is not an appropriate tool to achieve network savings:

> *[A] FIT does not address those constraints. In particular a DNSP receives no benefit where a FIT is paid to customers who install technology that does not address a specific constraint for which we are funded through our revenue cap. Such a requirement from a constraints management perspective would result in compensation for customers who are not directly addressing the constraint for which the funding was allocated.* [162]
>
> *The value of any such network benefit is highly location specific and consequently cannot be applied across the network as a whole with the creation of cross-subsidies. This locational element is evident because network constraints exist (and consequently can only be addressed) in certain locations.* [163]

This suggests that where benefits from solar PV to networks can be identified, they should be harnessed through other means. The National Electricity Rules (NER) already contains a number of mechanisms to incentivise efficient use of non-network solutions, including compensating embedded generators where it would be more efficient than network augmentation. These include:

- Cost-reflective distribution network tariffs: DNSPs are required to develop prices that better reflect the costs of providing services to individual consumers so that they can make more informed decisions about their electricity use. Cost-reflective network tariffs can incentivise investment in forms of embedded generation that result in increased on-site consumption and/or export during peak times.
- Network support payments: Embedded generators with capacity greater than 5 MW can negotiate with a TNSP to receive network support payments. These payments must reflect the economic benefits the embedded generator is providing to the TNSP by delaying or avoiding investment in the transmission network. Network support payments can also be negotiated between DNSPs and embedded generators, but their treatment under the NER is different.
- Avoided Transmission Use of System (TUoS) charges: DNSPs are required to make payments to embedded generators with a capacity of more than 5 MW if the presence of those generators

[162] Ergon Energy Corporation, sub. 34, p. 4.
[163] Energy Australia, sub. 25, p. 5.

reduces the energy supplied to the distribution network from the transmission network. The avoided TUoS payment reflects transmission charges the DNSP saves.

- The **Regulatory Investment Test for Distribution (RIT-D) and Transmission (RIT-T)**: The RIT-D and RIT-T require DNSPs and TNSPs to consider the costs and benefits of all credible network and non-network solutions where an investment need is projected to cost $5 million or more. In some circumstances, the benefits will be maximised, or the costs minimised, by procuring embedded generation capacity.
- The **Distribution Network Planning and Expansion Framework**: DNSPs must annually plan and report on assets and activities that are expected to have a material impact on the network. The rule also includes a number of demand-side engagement obligations on DNSPs. This provides transparency on DNSPs' planning activities and decision-making, and better enables non-network providers to put forward options — including embedded generation —as credible alternatives to network investment.
- The **Capital Expenditure Sharing Scheme** and the **Efficiency Benefit Sharing Scheme**: These schemes provide DNSPs and TNSPs with incentives to invest in and operate their networks efficiently by allowing them to retain a portion of any cost savings, and to share the remaining portion with customers. This incentivises a DNSP or TNSP to substitute a non-network solution for a previously anticipated investment in the network, if the former is more efficient.
- The **Demand Management Incentive Scheme (DMIS)**: The AER is required to publish an incentive scheme for network businesses to implement non-network investments where it is efficient to do so.
- The **Demand Management Innovation Allowance (DMIA)**: The DMIA provides DNSPs with funding to undertake research and development in demand management projects. The allowance is used to fund innovative projects that have the potential to deliver ongoing reductions in total demand or peak demand, which could include embedded generation initiatives.
- The **Small-generation Aggregator Framework**: This rule change aims to reduce the barriers to small generators participating in the market by enabling them to aggregate and sell their output through a third party (a Market Small-Generator Aggregator). This makes it easier for those parties to offer non-network solutions, and for DNSPs to procure those options when it is efficient to do so. [164]

No evidence was presented to this inquiry that these mechanisms were insufficient to ensure the installation of solar PV where it is a cost-effective alternative to network augmentation. Moreover, there are signs that firms are entering the market to provide third party energy aggregation and other services.[165]

The AEMC is assessing whether any further changes are required for small-scale embedded generation as part of a rule change request.[166] This is the most appropriate forum to assess whether there is a need for additional mechanisms. Using mechanisms that directly target

[164] AEMC 2015b, pp. 6–8.
[165] See Reposit Power http://www.repositpower.com/.
[166] On 14 July 2015, the Total Environment Centre and the Property Council of Australia submitted a rule change request to the AEMC that would alter payment arrangements for embedded generators in the National Electricity Market.

potential benefits, rather than a broad based feed-in tariff payment to all solar PV regardless of its impact, is a far more efficient and effective way to achieve outcomes.

Findings

6.1 Mandating solar feed-in tariffs to induce solar industry development and employment will be paid for by other business and residential consumers (including the least well-off consumers) and is likely to have an overall negative impact.

6.2 Solar PV has raised the cost of generating electricity in Queensland, with an estimated additional cost in the order of $75–$150 million in 2015. However, as the price of solar PV continues to decline, so will the additional cost of generation due to solar PV.

Solar PV owners should not be paid for any impact on wholesale prices. Governments do not reward generators for reducing the wholesale price, just as suppliers in other markets are not paid for increasing supply. Paying solar PV owners for any reduction in wholesale prices would likely result in overall higher electricity prices for Queensland consumers.

6.3 Solar PV may be able to defer network expenditure depending on specific location, penetration level and load characteristics. However, analysis of network data has not identified material network savings from solar PV in Queensland, and to the extent that savings may arise from 2015 to 2020, they will not outweigh the additional costs incurred from integrating solar PV onto the network.

6.4 We have not identified specific social benefits from solar PV exports that would warrant an increase in the feed-in tariff.

Recommendation

6.1 The Queensland Government should not increase feed-in tariffs to induce industry development, wholesale market and network infrastructure effects, or other social impacts. The evidence suggests that such a policy would come at a net cost overall.

7 EQUITY CONSIDERATIONS

The terms of reference ask us to consider a number of equity issues associated with feed-in tariffs including:

- *a method for determining a fair price for solar energy that does not impose unreasonable costs on electricity customers, particularly vulnerable customers;*
- *the perception of electricity customers about whether any cost to them from the fair value is 'unreasonable'; and*
- *wherever possible, the entity that receives the benefit of exported solar energy should be the entity to pay for that benefit.*

A considerable amount of the public debate on the desirability of mandating higher feed-in tariffs centres on their broader economic and distributional impacts. Many of the individual issues have been examined in Chapters 4–6. This chapter discusses the distributional (equity) impacts of above-market feed-in tariffs and considers the extent to which they might be fair.

Key points

- Much of the debate on the desirability of setting feed-in tariffs above market rates from solar PV centres on their broader economic and distributional impacts and whether these are fair.
- In terms of distributional impacts:
  - A policy to increase payment for solar exports above market rates provides a subsidy to solar investment, and increases the income of solar households. The gain to solar households is funded by all households, as they pay more for retail electricity.
  - Projections show that if a feed-in tariff was set to the variable component of the retail tariff, then by 2034–35 the benefit to a solar household would be between $4337 and $4790 for a 4.0 kW system; the aggregate level of subsidy would increase to more than $200 million; and higher electricity prices would cost non-solar households from $462 to $915.
  - Some low income households own solar PV systems, but these households are more likely to be non-solar households. Low income earners bear a disproportionate share of the burden of funding any subsidy to solar exporters.
- The existing subsidy to solar PV owners provided by the SRES, tariff structure subsidy and SBS is $597 million in 2015–16. Any mandated increase in feed-in tariffs would be in addition to that amount.
- An above-market feed-in tariff will increase the payments to solar PV owners, but raise retail electricity prices for non-solar customers. It is not clear that there are additional benefits that would outweigh the costs of higher electricity prices. Further, the costs of above-market feed-in tariff arrangements disproportionately impact the least well-off customers.

7.1 Context

A feed-in tariff that is above a market rate (measured as the avoided cost of energy) will result in income transfers between non-solar and solar customers through two mechanisms:

- The higher feed-in tariff means that solar owners receive more income for the same volume of energy exported to the grid.
- The feed-in tariff is funded by higher retail electricity prices.

Higher electricity prices reduce the welfare of electricity customers through a price and output effect:

- *Price effect*: the increased retail price means that a household or business pays more for the same amount of energy, reducing the income available to spend on other goods and services.
- *Output effect*: in response to the higher price, households and businesses consume less electricity.

If there are significant additional emissions reductions, then the welfare benefits of reducing emissions might be large enough to outweigh the welfare losses from higher prices (see Chapter 5).

Distributional effects

There are differing views on the distributional impacts of premium feed-in tariffs and other solar subsidy policies, in terms of who receives the subsidies and who pays for them:

- Some argue that largely wealthy households receive the subsidies at the expense of low income households.[167]
- Others interpret postcode or statistical area data and point to the uptake of solar by households on fixed incomes, such as pensioners, to suggest subsidies flow to lower income earners.[168]

The view that solar investment is correlated with income, and that subsidies to solar exports therefore have the effect of transferring income up the income scale, is reasonable given:

- the high cost of solar PV systems, particularly in the past, when systems routinely sold for greater than $10,000;
- low income households are budget-constrained, making financing investment in solar PV difficult; and
- low income households are more likely to be in rental accommodation.

While studies generally support these expectations, the limits on information that can be provided by analysing aggregate data has left findings open to counter-arguments. However, the data shows that:

- many Queensland households in the highest-income categories receive significant subsidies;
- the least well-off areas are disadvantaged by a subsidy policy. It can then be inferred that the least well-off households within those and other areas in Queensland are disadvantaged by a subsidy policy; and

[167] See for example, Nelson et al. 2012.
[168] Don Willis, sub. 16, p. 2.

- households who are the least well-off bear proportionally more of the cost of subsiding feed-in tariffs through higher retail prices.

These findings are discussed below.

7.2 Scenarios to assess different feed-in tariff rates

Modelled scenarios

To investigate the impacts of different above-market feed tariffs, and whether they would meet the criteria for being fair, four feed-in tariff scenarios were modelled. The scenarios are set out in Table 23.

Table 23: Above-market feed-in tariff scenarios

Scenario	*Description*
Scenario A	Feed-in tariff set at 10c/kWh and held in real terms over the projection period to 2034–35.
Scenario B	Feed-in tariff set at 15c/kWh and held in real terms over the projection period.
Scenario C	Feed-in tariff set equal to the projected variable component of the retail tariff (currently 22c/kwh).
Scenario D	Feed-in tariff set at the buyback rate (avoided cost methodology) plus 10 cents real. In 2015–16 this equates to around 16.5c/kWh.

The aggregate level of subsidy under the four scenarios will be influenced by the targeting of the subsidy policy. A feed-in tariff policy might apply to:

- all exports;
- all exports other than from systems installed under the SBS; or
- only exports from new systems induced by the policy.

For the modelling, we assumed that the feed-in tariff would apply to all exports other than exports from SBS systems. We assessed the distributional impacts by looking at what is known about the distributional characteristics of the existing stock of solar systems.

If a subsidy policy was targeted at only new investment — that is, the subsidies are not paid to exports from existing systems— then the distributional impacts of the policy would depend on the extent to which the spatial (geographic) and income characteristics of new investment matches that of the existing stock of solar PV systems.

The modelling has been based on a top-down approach; that is, solar investment projections are for Queensland as a whole and not built-up by individual projections at a detailed regional level.

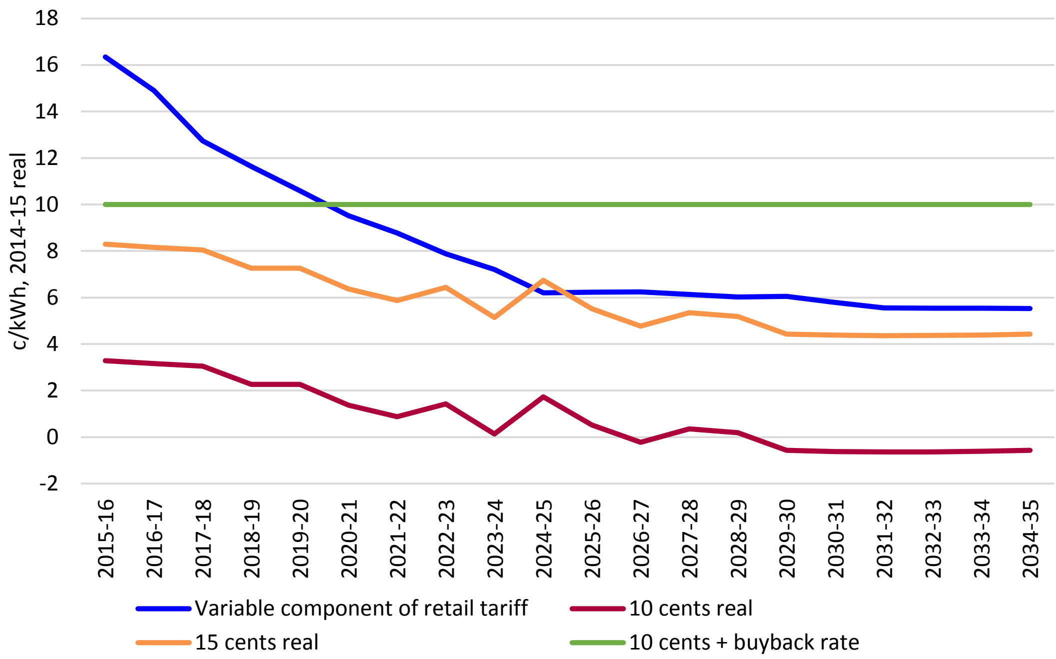
This is a reasonable approach for a number of reasons, including the difficulty of predicting in what regional areas new investment would occur under a new subsidy policy. One may expect more investment in areas with low solar penetration rates, but areas with high penetration rates are still a distance from saturation.

Increased income for solar exporters through a higher feed-in tariff

Up until 2020–21, a feed-in tariff set equal to the variable component of the retail tariff provides the highest subsidy (Scenario C). However, the level of subsidy under this scenario declines with projected falls in the variable component of the retail tariff combined with projected increases in wholesale energy costs.

On average, over the projection period to 2034–35, Scenario D (buyback rate plus 10 cents) provides the highest average per unit subsidy (Figure 43), compared to the base case. The base case is the existing buyback rate, valued as the avoided costs of wholesale energy purchase.

Figure 43: Increase in feed-in tariff under different scenarios compared to the base case—2015–16 to 2034–35



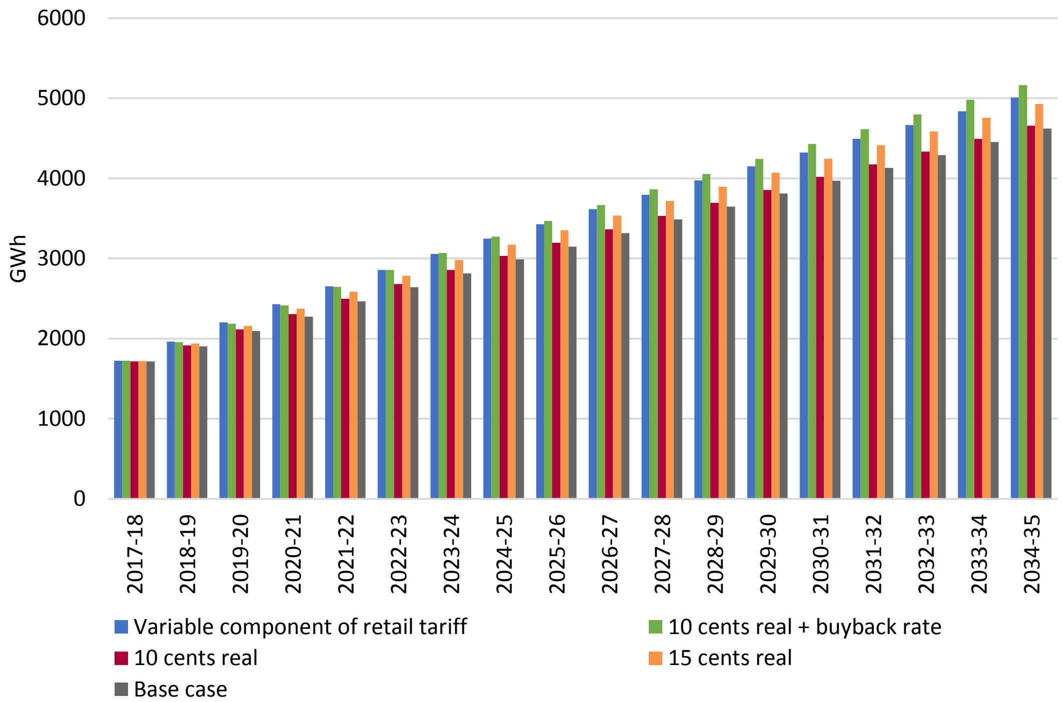
Source: ACIL Allen Consulting 2015.

Exports to the grid under different feed-in tariff assumptions

The projected volume of electricity generated from solar PV systems and exported to the grid varies under the four subsidy scenarios, as different feed-in tariffs result in different rates of investment in solar PV systems (Figure 44).

The variable component of the retail tariff (Scenario C) produces a larger investment response leading to more solar generation and exports. However, the investment response is sluggish or 'inelastic'.

Figure 44: Volume of solar exports under different subsidy scenarios



Source: ACIL Allen Consulting 2015; QPC calculations.

Estimated wealth transfer from non-solar to solar households under different feed-in tariff assumptions

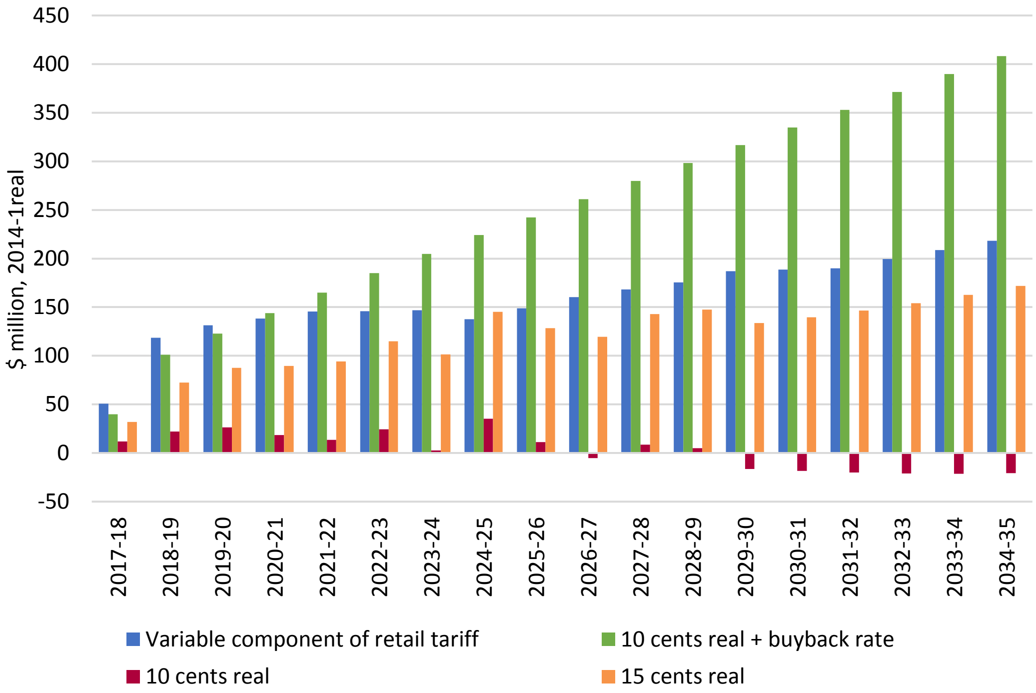
Figure 45 shows the estimated cost of feed-in tariffs under the different scenarios.

Under the base case — where the feed-in tariff reflects market rates — there are no scheme costs and no additional impacts on electricity prices, as retailers purchase solar PV exports at market rates.

A feed-in tariff above market rates will provide additional benefits to solar PV exporters but incur additional costs. These costs would need to be recovered through higher electricity prices. The buyback rate plus 10c/kWh (Scenario D) provides the highest benefit to solar PV owners, at a scheme cost of $224 million in 2024–25, growing to $408 million by 2034–35. Where the feed-in tariff is set equal to the variable component of the retail tariff (Scenario C), the transfer from non-solar to solar households is estimated at $138 million in 2024–25, growing to $218 million by 2034–35.

Given projected trends in wholesale energy costs, there is not a significant difference between a feed-in tariff of 10 cents in real terms over the projection period (Scenario A) and a feed-in tariff based on the avoided cost methodology (as currently used by the QCA in establishing regional feed-in tariffs). In some years, solar owners should be better off under the base case than Scenario A.

Figure 45: Estimated cost of feed-in tariffs under different scenarios



Source: ACIL Allen Consulting 2015; QPC calculations.

Table 24 shows the NPV of scheme costs to 2034–35, which range from $82 million for Scenario A to $2.34 billion for Scenario C (discounted at six per cent).

Table 24: Net present value of the wealth transfer to solar exports, $ million

	Discount rate	
Scenario	*0%*	*6%*
10 cents real	$56	$82
15 cents real	$2184	$1207
Variable cost component avoided	$2860	$1605
10 cents real + market buyback rate	$4443	$2338

Notes: Net present value of annual subsidy paid for solar exports to 2034–35.

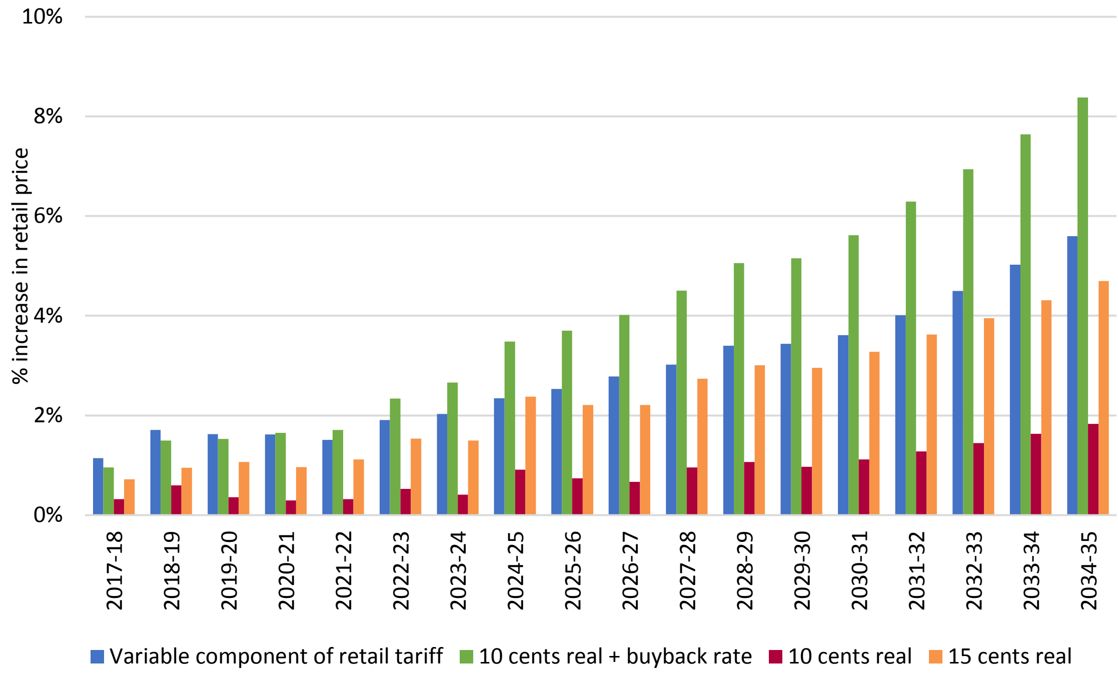
Source: ACIL Allen Consulting 2015; QPC calculations.

Estimated impact on retail electricity prices

A subsidised feed-in tariff will increase retail electricity prices (Figure 46). The retail price impact is estimated to raise electricity prices by between 1.8 and 8.4 per cent by 2034–35.

Under each of the modelled scenarios, the aggregate level of subsidy increases over time as the stock of solar panels, and therefore exports, increases due to new investment.

Figure 46: Retail price impacts of subsidised feed-in tariffs



Note: Underlying price data in 2014–15 real dollars.

Source: ACIL Allen Consulting 2015, QPC calculations.

Estimated distributional impact of above-market feed-in tariffs

The cost of funding subsidies to solar households will not be evenly shared in terms of the magnitude of the impact per household, or proportional to household incomes:

> *The economic literature clearly describes feed-in tariff policies as outsourced forms of taxation, whereby the costs of State Government policy are recovered from electricity consumers in proportion to how much electricity they use, irrespective of household income.*[169]

If a feed-in tariff is set equal to the projected variable component of the retail tariff (Scenario C), then a low-consumption non-solar household will pay $462 more in real terms (undiscounted) due to higher electricity prices (Table 25). A high-consumption household will pay $915 more. In the table, a positive number represents a gain in income to the household and a negative number represents a loss.

[169] Nelson et al. 2012, p. 7.

Table 25: Net present value of cross-subsidies to 2034–35, $2014–15 real

	Low-consumption household		*Medium-consumption household*		*High-consumption household*	
Discount rate	*0%*	*6%*	*0%*	*6%*	*0%*	*6%*
FiT = 10 cents real						
Net impact on solar household	465	403	363	358	330	342
• Subsidies to solar exports	463	402	463	402	463	402
• Solar household—value of avoided imports	70	33	70	33	70	33
• Solar household—retail electricity	–67	–31	–170	–76	–202	–93
Non-solar household—retail electricity	–137	–63	–240	–109	–272	–125
FiT = 15 cents real						
Net impact on solar household	3234	1992	2948	1864	2858	1820
• Subsidies to solar exports	3227	1987	3227	1987	3227	1987
• Solar household—value of avoided imports	195	90	195	90	195	90
• Solar household—retail electricity	–188	–85	–474	–213	–564	–257
Non-solar household—retail electricity	–384	–175	–670	–303	–760	–347
FiT = variable component of retail tariff avoided						
Net impact on solar household	4790	3050	4448	2893	4337	2836
• Subsidies to solar exports	4780	3042	4780	3042	4780	3042
• Solar household—value of avoided imports	236	112	236	112	236	112
• Solar household—retail electricity	–226	–105	–568	–262	–679	–318
Non-solar household—retail electricity	–462	–218	–804	–374	–915	–431
FiT = Buyback rate + 10 cents real						
Net impact on solar household	5539	3178	5052	2964	4902	2891
• Subsidies to solar exports	5528	3170	5528	3170	5528	3170
• Solar household—value of avoided imports	331	150	331	150	331	150
• Solar household—retail electricity	–319	–142	–806	–357	–957	–429
Non-solar household—retail electricity	–650	–293	–1137	–507	–1287	–580

Notes: Solar export cases are based on: a solar PV system size of 4.0 kW; system installation in postal zone 3; a base case export rate for a 4.0 kW system; and low, medium and high annual electricity consumption levels of 5100 kWh, 7600 kWh and 10,100 kWh, respectively.

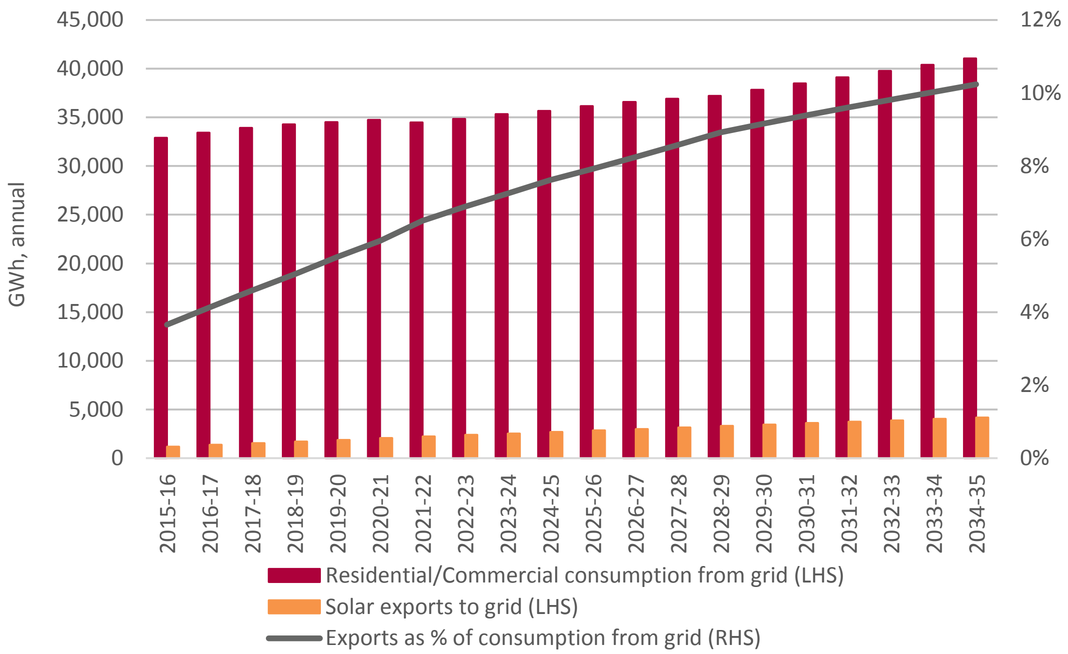
Source: QPC calculations.

The amount gained by a solar household through higher export revenues depends on the volume of exports. The case studies are based on a 4.0 kW system installed in postal zone 3 (which covers the majority of Queensland's population).

In this case, a solar household with low consumption will have a net gain of $4790, and $4337 for a high consumption household. Higher consumption levels mean that more energy has to be imported from the grid for both non-solar and solar households, so that, with a higher retail electricity price, a high-consumption solar household receives a lower net cross-subsidy. Solar households also receive an increased benefit from avoiding imports from the grid resulting from the higher retail electricity tariff.

The income received by a typical solar household is significantly greater than the income lost by a typical non-solar household. This is because the volume of solar exports is a small fraction of the volume of retail electricity imports from the grid (Figure 47). Solar exports as a percentage of retail imports rises from just under 4 per cent in 2015–16 to just over 10 per cent by 2034–35. Therefore, the per-unit cost of the subsidy is distributed over a much larger volume of retail electricity imports.

Figure 47: Volume of solar exports versus volume of retail consumption from the grid



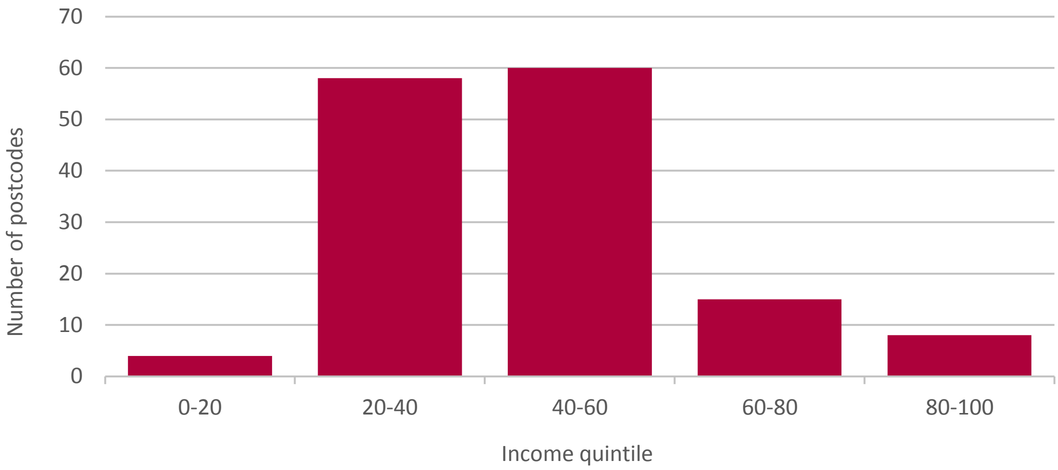
Source: ACIL Allen Consulting 2015; QPC calculations.

7.3 Distributional impacts through the cross-subsidy to solar exports

Correlation with incomes

An analysis of average income and solar PV installation data by postcode indicates that the costs of a subsidised feed-in tariff are likely to fall disproportionately on those areas with the lowest household incomes. While some low income households may own a solar PV system, policies are evaluated based on impacts across large populations. Out of the 145 postcodes in Queensland with a solar PV penetration rate above 30 per cent, only four are in the lowest-income quintile (Figure 48).

Figure 48: Number of Queensland postcodes above 30% penetration rate, by income quintile



Source: ESAA, sub. 37, p. 2.

Some areas that rank relatively low on the basis of income (or flow) measures may rank differently based on wealth (or stock) measures. For example, some areas may have concentrations of retirees who may have more assets, but have low incomes. However, data is not available on a broad wealth measure at a disaggregated regional level.

A positive correlation between income and solar PV investment is consistent with evidence from California (Box 21). While solar subsidies flow proportionally less to those on the lowest incomes, subsidies are not as regressive as they once were when system prices were prohibitive.

Box 21: Evidence from the United States on the distributional impacts of solar subsidies

California began encouraging the installation of residential solar PV in the mid-1990s with direct and indirect subsidies. From 2007, California provided capacity-based rebates under the California Solar Initiative (CSI) and the federal government provided a tax credit for solar and other renewable energy sources. In addition, the retail rate structure (an increasing block structure) provided further incentives for the installation of residential solar PV.

In 2007, the CSI received 813 rebate applications for households earning less than $50,000 annually, 1292 applications for households earning greater than $100,000, 1521 applications for households earning $75,000–$100,000, and 2367 applications for households earning $50,000–$75,000. In 2007, rebates transferred income to households earning more than $75,000 annually far more frequently than it did to households earning less than $50,000. In addition, the $50,000 income bracket used for reporting the distributional impacts of the program is not representative of those most in need as those households would have annual incomes substantially below $50,000. The *median* household income in California in 2007 was $59,948.

As solar PV prices fell and the diffusion of solar PV increased, investment in solar in the $50,000–$75,000 bracket grew most strongly. In 2011, rebate applications for this income bracket totalled 10,531 applications while the number of applications in total for the other brackets was 11,417 applications. The number of applications for households earning greater than $100,000 and less than $50,000 was roughly the same at 2652 and 2962 applications, respectively. In 2011, the number of rebate applications for those in the lowest reported income bracket was greater than the highest income bracket for the first time.

While solar investment was positively correlated with income, Borenstein 2015 found that the concentration of PV in the highest income brackets in California fell over the period 2007 to 2013, with most of the change happening in the last couple of years of the study period.

Source: CPUC 2012; Bishaw & Semega 2008; Borenstein 2015.

Relative socio-economic disadvantage

An alternative to postcode analysis is to use the ABS's index of relative socio-economic disadvantage. The index is a general socio-economic index that summarises a wide range of information about the economic and social resources of people and households within an area.

The index aims to provide a broader measure of disadvantage/advantage compared to measures based solely on household incomes.

The rate of penetration of solar PV systems under the SBS was greater in statistical areas (SA2s) that score relatively well on the ABS's index of socio-economic disadvantage. For areas that are relatively most disadvantaged (quintile 1), 26 SA2s have a solar penetration rate greater than 20 per cent of dwelling structures[170] (Table 26). In contrast, the number of better-off areas (quintiles 3–5) that have penetrations rates greater than 20 per cent is higher (ranging from 37 to 41 areas). The data indicates that the high levels of subsidies under the scheme are not targeted at the most disadvantaged areas.

When all solar PV systems are considered, the number of areas with penetration rates greater than 20 per cent of dwelling structures is fairly equal across quintiles (ranging from a low of 65 areas to a high of 77 areas).

Investment activity in non-SBS solar PV systems has been somewhat greater in areas ranked in the lowest three quintiles of disadvantage (as indicated by the larger relative increase in the number of statistical areas meeting the threshold penetration rate).

Table 26: Queensland areas ranked by solar penetration and socio-economic disadvantage (Number of statistical areas (SA2s))

	*Relative socio-economic disadvantage quintiles**				
	1 (most disadvantaged)	*2*	*3*	*4*	*5 (least disadvantaged)*
SBS penetration > 20%	26	21	39	37	41
All solar PV system penetration > 20%	65	66	77	69	70
Difference in penetration rates	39	45	38	32	29

*Notes: * Quintiles 1–4 include 101 statistical areas (SA2s) each, while quintile five includes 102 areas. The quintiles are based on the proportion of areas in the bottom three deciles of the Australian Bureau of Statistics' Index of Relative Socio-Economic Disadvantage. SA2s ranked in quintile '1' are relatively the most disadvantaged. SA2s ranked in quintile '5' are the least disadvantaged (i.e. are better off).*

Source: Queensland Government Statistician's Office 2015; ABS 2008; Energex and Ergon Energy unpublished data; QPC calculations.

However, when all areas are considered, data indicates that if a subsidy policy was implemented that paid for exports from the existing stock of non-SBS systems, then the pattern of income transfers would still align closely with the pattern of income transfers based on the SBS. Area rankings of export volumes for SBS exports and non-scheme exports are highly correlated (i.e. if an area has relatively high export volumes under the SBS, it also tends to have relatively high export volumes for other solar exports). If the subsidy policy was restricted to new investments in solar only, but the pattern of investment followed the pattern of recent years, then the result would still hold.

Longer-term, the geographic pattern of new investment should dampen the degree of income transfers between areas. However, this may take time as even areas that rank high on export volumes or penetration rates are not at saturation point, such that a lot of new investment could occur in areas that already have relatively high levels of investment in solar.

[170] The penetration rates are biased upwards as the solar PV system data is based on 2015 data, while the data for dwelling structures is based on the 2011 census and, therefore, does not take into account the increase in dwelling structures over the last four years.

Arguably, distributional concerns should focus on the least well-off and not the transfers that do or do not occur between higher-income and relatively more-advantaged groups.

As a subsidised feed-in tariff is paid on exports, rankings of an area's level of solar exports should provide a more direct measure of income flows between areas.

Those areas that are ranked as the most disadvantaged are also more likely to have the lowest level of solar exports from non-SBS systems (32 areas, Table 27). Moving beyond a focus on the least well-off, there is no strong pattern in the data between the level of relative disadvantage and the level of solar exports from an area, and thus income transfers to the area under a subsidised feed-in tariff.

Table 27: Queensland areas ranked by export volumes and socio-economic disadvantage (Number of statistical areas (SA2s))

	*Relative socio-economic disadvantage quintiles**				
Ranking of level of exports (kWh) by quintile	*1 (most disadvantaged)*	*2*	*3*	*4*	*5 (least disadvantaged)*
1 = lowest level of exports	32	16	13	20	21
2	12	25	24	16	24
3	19	25	17	17	23
4	17	23	23	17	21
5 = highest level of exports	21	11	25	27	17

Notes: Export volumes exclude exports from SBS systems.

Source: Queensland Government Statistician's Office 2015; ABS 2008; Energex and Ergon Energy unpublished data; QPC calculations.

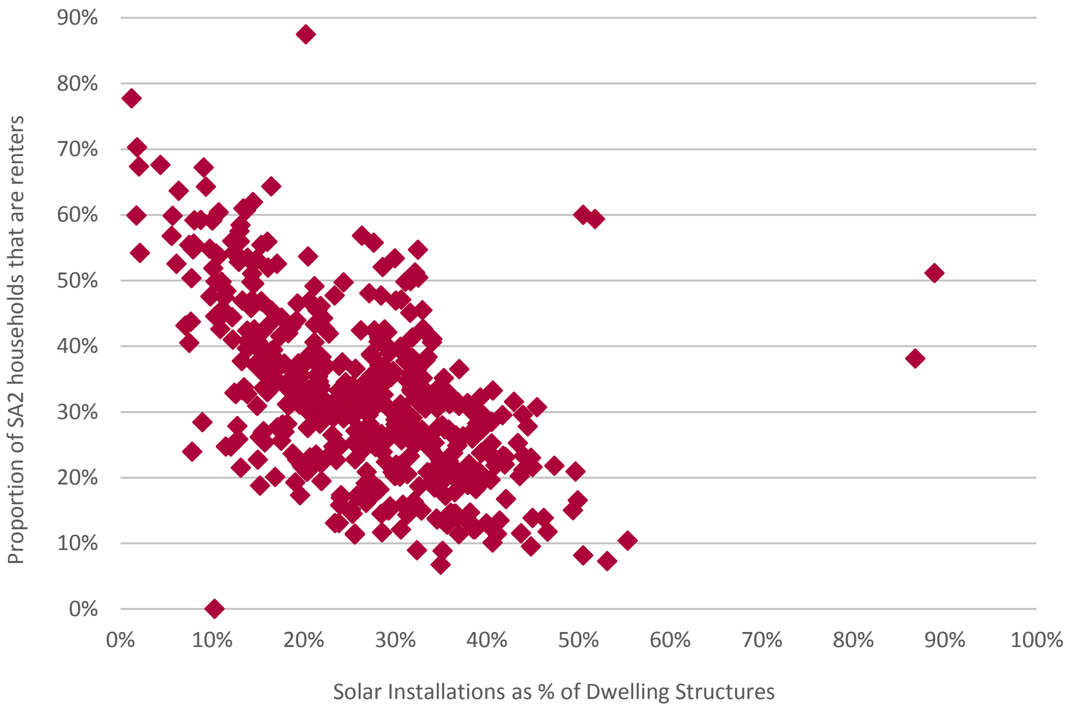
Within each SA2 or postal area, there is a distribution of solar households by income or wealth. Each income or relative disadvantage quintile has households which do and do not own solar systems. Aggregate data only captures 'averages' and not the shape of the distribution, or how many households of each type are in each quintile. The data does not reveal whether ownership is concentrated in the relatively well-off within an area even if the area on average is relatively not well-off by Queensland standards. Data at the household level is required to provide this sort of information. The QPC investigated linking ABS household data incorporating information on household energy expenditure patterns, including solar data, with income data from the 2011 census. However, the data is fairly dated, given the rapidly developing solar market.

Solar investment and home ownership

Low income households are less likely to own a solar PV system both because they are income constrained — solar PV systems require a significant investment even after the major price reductions of recent years — and because they are less likely to own their homes. There is a strong, positive correlation between home ownership and solar PV system penetration rates to date (Figure 49), and home ownership is positively correlated with household incomes.

Apart from ownership, renters are more likely to reside in dwelling structures that are less suitable to the installation of solar PV systems, such as apartments.

Figure 49: Solar PV penetration and proportion of Queensland dwellings that are rentals



Notes: Y-axis is based on rental data at the geographic classification level of Statistical Area level 2 (SA2) from the Queensland Regional Database. X-axis solar penetration data is based on Energex and Ergon data mapped to SA2s, combined with data on dwelling structures from the Queensland Regional Database. 506 SA2s are included in the scatterplot.

Source: Queensland Government Statistician's Office 2015; QPC calculations.

To further investigate the influence of income and home ownership on investment in solar PV, a range of econometric models were estimated using a single cross-section of Queensland SA2 data (Appendix I). The results indicate that the number of rental properties in a region is associated with lower installed solar capacity and that rental properties as a proportion of total dwelling structures is associated with lower solar penetration rates. In contrast, owner occupied homes are positively associated with higher solar investment. The results also provide support for:

- a negative relationship between installed solar capacity and penetration rates and the proportion of a region's population in the bottom three deciles of the ABS Index of Relative Socio-Economic Disadvantage; and
- a positive relationship between a population's access to economic resources, proxied by the ABS Index of Economic Resources, and higher levels of installed solar capacity and penetration rates.

7.4 Distributional impacts through the increase in retail electricity prices

Low income households spend relatively more on electricity than higher income households. Australian households with the lowest incomes spent on average six per cent of their weekly income on electricity in 2012, compared to 0.8 per cent for those households in the highest income quintile (Table 28).

Therefore, the increase in retail electricity prices from a subsidised feed-in tariff will impact proportionally more on low income households. Households in the lowest income quintile are most likely to be in a position of 'financial stress' already, or to have no disposable income as a buffer to cover policy-driven increases in the cost of living.[171]

Table 28: Australian household expenditure on electricity by income quintile, 2012

	Equivalised disposable household income quintile					
	Lowest	*Second*	*Third*	*Fourth*	*Highest*	*All households*
Income per week						
Mean gross household income ($)	382	871	1482	2279	4345	1872
Mean equivalised disposable household income ($)	313	528	724	967	1585	929
Average weekly expenditure on electricity ($)	23	29	30	31	33	29
Electricity expenses as a % of weekly income						
Mean gross household income (%)	6.0%	3.3%	2.0%	1.4%	0.8%	1.5%
Mean equivalised disposable household income (%)	7.3%	5.5%	4.1%	3.2%	2.1%	3.1%

Notes: As household size increases, consumption needs also increase but there are economies of scale. An equivalence scale is used to adjust household incomes to take account of the economies that flow from sharing resources and enable more meaningful comparisons across different types of households. Equivalising factors are calculated based on the size and composition of the household, recognising that children typically have fewer needs than adults.

Source: ABS 2013.

The data in Table 28 are averages for each income quintile. Low income households that are also high consumption households will spend considerably more than 6 per cent of their weekly income on electricity (for example, large families on low incomes).

In NSW, IPART found median household spending on energy varies across income categories with low income households spending proportionally more on energy:

- For middle and higher income households (those households earning more than $46,000 per year), median household spending on energy will range from about 2 to 4 per cent of disposable income.
- For low-income households ($38,000 or less per year), median spending on energy will range from 5 to 8 per cent of disposable incomes. Households in the lowest income category (earning $14,000 to $20,000 annually) are likely to spend about 8 per cent of their disposable income on energy:

> *households with energy use in the lowest 10th percentile will spend about 4 per cent of their income on energy, while those with energy use in the 90th percentile will spend almost 14 per cent of their income on energy.*[172]

Low income households are also most at risk of the accumulated cost of policies. For example, while the increase in retail electricity prices from a subsidised feed-in tariff may appear small initially, the 'marginal' increase is on top of a retail price that has already risen due to policies, such

[171] For a detailed discussion of the impact of rising retail electricity prices on low income households see Chester 2013 and Westmore 2014.

[172] IPART 2012a, pp. 72–73.

as the RET and SBS (Chapter 2 provides a decomposition of the components of retail electricity prices), and earlier regulated network security standards.

The solar market is evolving with new products which will help address impediments to solar investment for those on low incomes, but these changes will take time. A subsidised feed-in tariff will continue to have negative impacts on the least well-off:

> *[Setting a mandatory FiT above avoided costs] risks exposing low-income earners that are unable to access solar PV to even higher electricity costs. There are a range of barriers that can limit a vulnerable/hardship customer's access to solar PV, including limited access to capital (although emerging PPA business models provide a commercial solution to this) and reliance on rental accommodation. Further, such customers often have limited capacity to moderate their energy consumption. Simply increasing the value of solar PV FiT rates does little to assist these customers.*[173]

Overall, the distributional impacts of subsidised feed-in tariffs are likely to continue to be regressive:

> *Nelson, Simshauser and Kelley (2011) found that in the case of New South Wales, solar PV owners tended to be comparatively wealthy home-owners, and the very private benefits of the units were comprehensively and unambiguously internalised by the participating households. In contrast, low income and rental households incur the costs without receiving any visible benefit. In addition, since the charge to all households is based on electricity usage and not income, the cost recovery process was found to be highly regressive, with low income households paying an effective tax incidence that was 2.7 times the rate paid by high-income households.*[174]

The negative impacts of the subsidy policy may be partially offset by various Queensland Government and electricity retailer assistance programs targeted at those who are least well-off and unable to meet their electricity bills (discussed in detail in the QPC's electricity pricing inquiry report).

Other sources of cross-subsidies

In considering the distributional impacts of a subsidised feed-in tariff, it is noteworthy that pre-existing policies already result in cross-subsidies between customer groups. Solar subsidy schemes and the structure of tariffs provide significant cross-subsidies:

- *Solar Bonus Scheme*: the 44 cent feed-in tariff results in higher retail electricity prices paid for by all consumers of retail electricity from the grid. As non-solar households outnumber solar households, and as average consumption from the grid is less for solar households, the increase in retail prices is mainly paid for by non-solar households; and
- *Tariff re-balancing*: as tariffs are not fully cost reflective, and the variable component of retail tariffs also provides a contribution to fixed costs, solar households are able to reduce their share of payments covering network costs through reducing their consumption (imports) from the grid.

Through reducing their imports from the grid, solar households contribute less to the cost of maintaining the electricity network because a large proportion of fixed network costs is re-couped through variable charges rather than fixed charges:

> *Secondly, the SRES and feed-in tariffs build on an implicit (and largely unintended) subsidy afforded PV systems through the current structure of retail electricity bills in Australia. In general, the variable component of retail electricity tariffs do not reflect the economically variable or avoidable*

[173] ESAA, sub. 37, p. 5.

[174] Nelson et al., 2012, p. 2.

component of the true cost of delivering electricity to retail consumers. Whilst around 90% of the final retail bill is provided as a variable component, the true fixed proportion of this cost, economically speaking, is far greater than 10%.

Accordingly, irrespective of feed-in tariffs or other subsidies, a household installer of a PV system is afforded an implicit subsidy for every unit of electricity produced by a PV system and consumed by the owner of the system. The value of this implicit subsidy is equal to the difference between the variable component of the retail bill and the true economically variable component of the cost of electricity. [175]

On a per household basis, the existing cross-subsidy from non-solar to solar households is significant:

Distributed generation is not the largest driver of implicit network cross-subsidies between customer segments, with more significant distortions caused by peak demand appliance use such as air-conditioning. However, under volumetric tariffs the average current cross-subsidies between solar and non-solar households have been estimated as at approximately $120 per household by independent studies recently commissioned by the Australian Energy Market Commission (AEMC).

Importantly, analysis of future energy scenarios indicates that, in the absence of cost reflective tariffs being implemented, these implicit cross subsidies due to network tariffs will increase substantially over time, potentially reaching up to $655 per annum by 2035.[176]

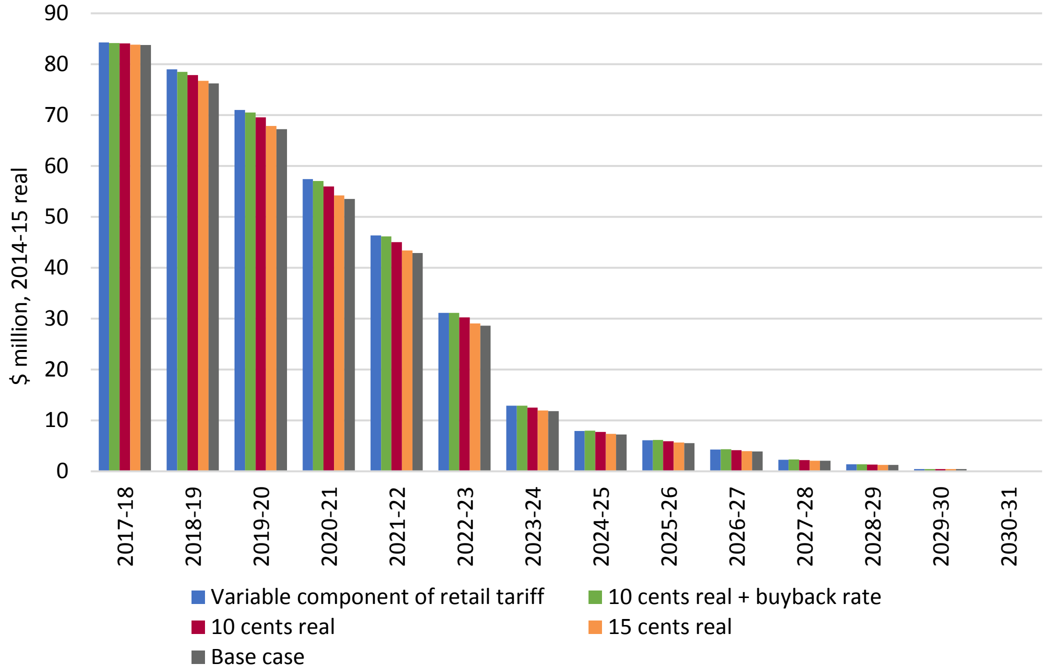
The lesser contribution of solar households to network costs relative to non-solar households can be considered a cross-subsidy as both types of households impose similar costs on the network — the cost of maintaining a connection and capacity to deliver energy — while contributing different levels of money towards covering network costs, such as the cost of maintaining the network.

The level of the network subsidy in 2017–18 is estimated at close to $90 million under each of the feed-in tariff scenarios modelled (Figure 50). Differences in the level of subsidy under the scenarios is due to differences in the volume of imports displaced from the grid by solar PV.

The level of the subsidy declines quite rapidly due to the assumption of network tariff re-balancing. ACIL Allen modelling assumes that the variable component of the network tariff — the tariff Energex and Ergon Energy charge energy retailers for network services — reduces to the point where revenues generated through fixed charges account for 80 per cent of the network tariff in 2030, and the variable component accounts for the other 20 per cent. At the end of the re-balancing transition period to 2030, the QPC has assumed that the re-balanced tariffs are fully cost-reflective, and therefore solar and non-solar households make the same contributions to network fixed costs (that is, the cross-subsidy is zero).

[175] ACIL Tasman 2011, p. 88.
[176] Energy Networks Association, sub. 41, p. 1.

Figure 50: Avoided contribution of solar households to network costs



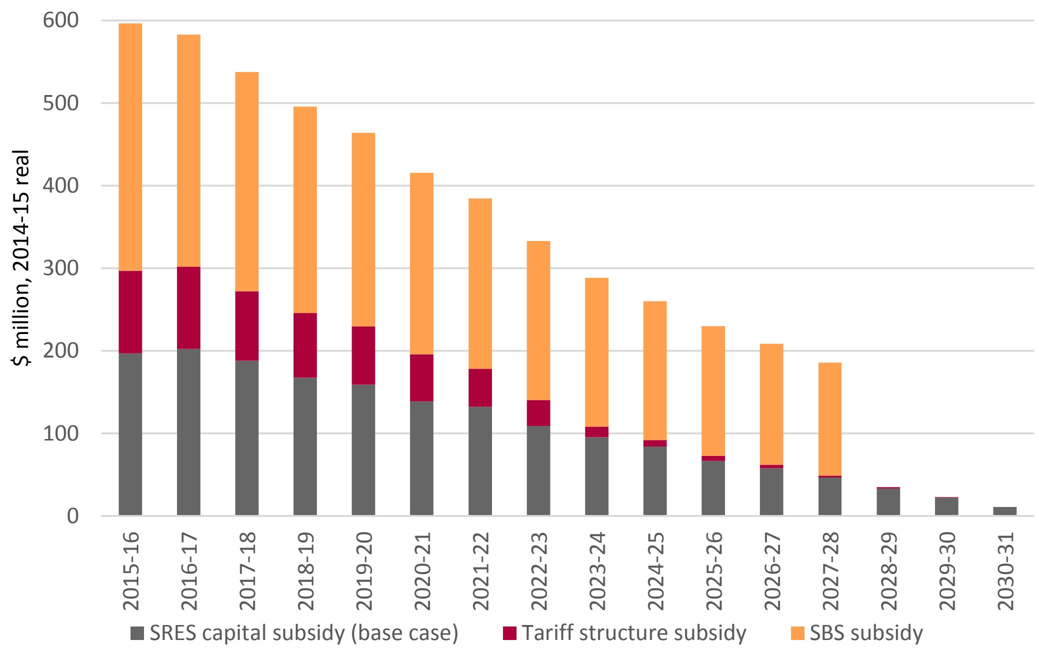
Notes: Per unit subsidy calculated using ACIL Allen 'network cost avoided by PV estimates' less an estimate of the underlying cost-reflective variable component of network tariffs based on QPC assumptions.

Source: ACIL Allen Consulting 2015; and QPC calculations.

Solar is subsidised through the SRES capital subsidy, the current structure of network tariffs which are not cost-reflective, and the SBS. In addition, there are a large range of other subsidies provided to solar not considered in the estimates below (see the partial list at the beginning of Chapter 5).

The scale of existing subsidies to solar provided by the SRES, tariff structure subsidy and SBS is in the order of $597 million in 2015–16 (Figure 51). Each of the subsidies decline over time.

Figure 51: The scale of existing subsidies to solar PV



Notes: SRES subsidy based on base case modelling of investment in solar PV. Different feed-in tariffs will influence investment in solar PV and, hence, the aggregate level of subsidies provided through the SRES.

Source: ACIL Allen Consulting 2015; and QPC calculations.

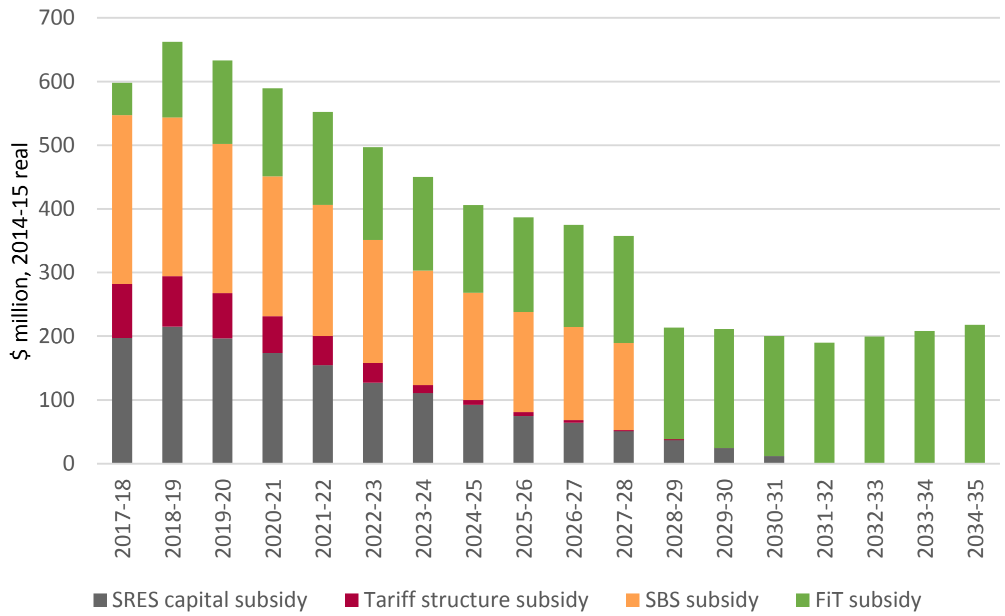
A new subsidy provided through a feed-in tariff set at the rate of the variable component of the retail tariff would result in aggregate subsidies to solar of $598 million in 2017–18 in real terms, comprising a SRES subsidy of $197 million, a tariff structure subsidy of $84 million, a SBS subsidy of $265 million, and a feed-in tariff subsidy of $51 million (Figure 52). The aggregate subsidy reduces through time as a result of the scheduled decline in the SRES subsidy, the assumption of tariff re-balancing, and the cessation of the SBS in 2028.

The level and pattern of subsidies under a feed-in tariff of 15 cents real is very similar to the variable component scenario.

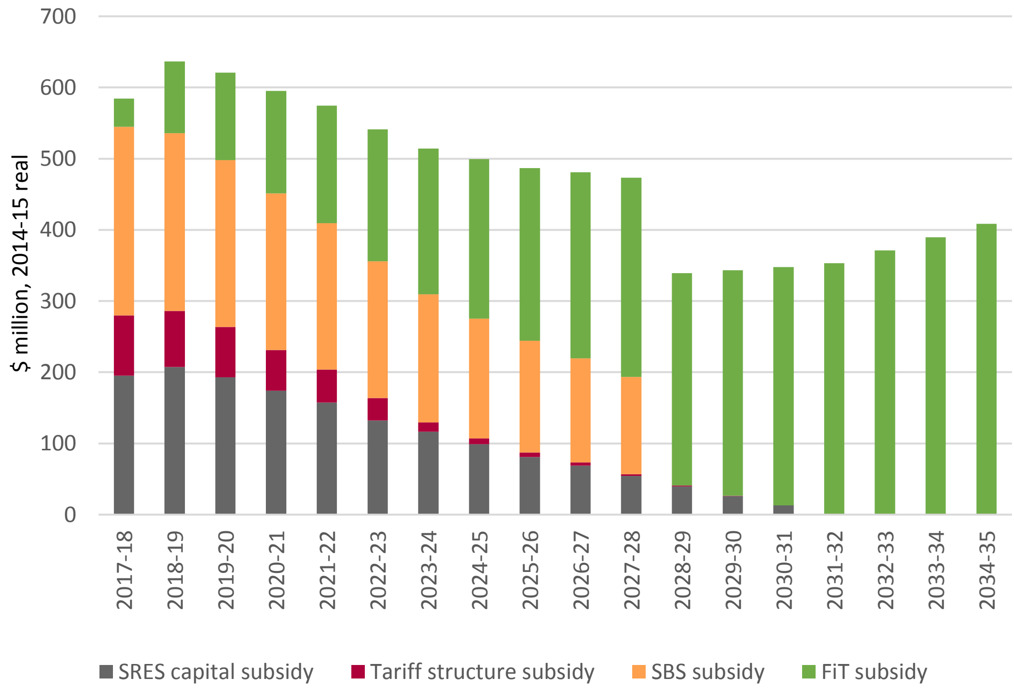
Under the scenario where the feed-in tariff is equal to the market buyback rate plus 10 cents real, the average level of subsidies is higher than the other scenarios driven by the additional subsidy provided through the feed-in tariff.

Figure 52: Aggregate subsidies to solar PV

Scenario: variable component of retail tariff scenario



Scenario: 10 cents real plus buyback rate



Source: ACIL Allen Consulting 2015; QPC 2016a; QPC calculations.

7.5 Conclusion

The terms of reference ask us to determine a fair price for solar energy that does not impose unreasonable network costs on electricity customers, particularly vulnerable customers, and that wherever possible the entity receiving the benefit of exported solar energy should be the entity to pay for that benefit.

An above-market rate for a feed-in tariff will increase the payments to solar PV exporters, but will also increase retail electricity prices for non-solar customers.

It is not clear that there are additional benefits for non-solar users that would suggest that the benefits of paying higher electricity prices due to an above-market feed-in tariff outweigh the costs. Further, there is evidence that the costs of above-market feed-in tariff arrangements disproportionately impact vulnerable customers.

Accordingly, we have not recommended that the Queensland Government implement a mandated feed-in tariff that reflects above-market prices for the value of exported energy.

Findings

7.1 Solar PV is subsidised through the SRES, Solar Bonus Scheme, and the structure of electricity tariffs:

- (a) The combined subsidy is $597 million in 2015–16. This does not include other subsidies through national and state government policies.
- (b) Any new subsidy provided through a feed-in tariff would be in addition to these amounts.

7.2 While some low income households own solar PV, the overall distributional impact of solar PV subsidies is to transfer income from non-solar households to solar households, and to raise the cost of living for those on the lowest incomes:

- (a) Subsidies to solar exports result in a large and growing transfer of income from non-solar households to solar households.
- (b) In considering the distributional consequences of a subsidy policy, if the focus is on the least well-off, then the policy is regressive. On equity grounds, such a policy is demonstrably unfair.

8 BARRIERS TO A WELL-FUNCTIONING SOLAR EXPORT MARKET

The terms of reference ask us to identify any barriers or constraints (technical, market, regulatory or otherwise) to exported solar energy in Queensland, and to provide options to address those barriers.

Key points

- Barriers to a well-functioning solar export market can include technical, regulatory and policy barriers. This inquiry has not identified significant barriers to solar PV investment or solar PV pricing.
- That said, there are a number of issues that affect the solar export market:
  - Trading of solar exports is generally tied to the purchase of retail electricity;
  - Metering and tariff structures can limit efficient solar export pricing, including time-of-export pricing;
  - Information problems may inhibit consumer decision-making; and
  - Policy design can distort efficient investment and impede the uptake of solar PV in regional Queensland.
- Not all impediments can, or should be, addressed by government. Some issues will be addressed by the market through, for example, emerging market offerings. Others are best addressed at the broader electricity market level to consider the best outcome, not just for solar PV, but for all participants.
- There is no restriction to retailers offering time-of-export pricing for solar PV exports, although existing metering may be an impediment. Under a range of scenarios, solar PV owners are paid more under existing flat tariffs compared to what they would receive under time-of-export tariffs. And although there may be efficiency gains from time-of-export pricing, they are not necessarily significant, particularly compared to the gains from time-varying pricing of electricity more broadly. Time-of-export pricing should evolve in the market where there are benefits from its use.
- A potential barrier to solar PV embedded generation is the ability of distribution networks to use market power or information asymmetries to limit connection:
  - No evidence was presented to indicate that network businesses are unnecessarily limiting solar PV connection for small customers. However, there is a case for improving the transparency and expediency of larger-scale connections.
- The main barriers identified by consumers related to information problems. A wide variety of information is available, but misconceptions about the return on solar PV investments and wholesale versus retail energy prices from feed-in tariffs prevail. This reinforces an ongoing role for regulators, peak bodies and government in consumer education.
- Going forward, the government should ensure that any policies do not provide more favourable treatment to rooftop solar over other forms of solar PV (commercial, large-scale and community), other forms of generation and low-emissions technologies.

8.1 Context

Many regulatory, technical, and market characteristics impact the solar export market. Not all impediments to a solar export market are barriers. Some are simply natural characteristics of the market. For example, the amount of rooftop solar PV in Queensland will be limited by the number of rooftops. Many dwellings are effectively prohibited from installing solar PV due to site orientation (no north-facing roof space) or dwelling construction (asbestos roofs, roofs with inappropriate structural support).[177]

Moreover, there are legitimate reasons for certain barriers such as health and safety standards, and network safety and reliability. And not all barriers can be addressed in a cost-effective way.

As a result, a focus of this inquiry was to identify *policy-relevant* barriers that *unnecessarily* impede solar exports or solar export pricing. Such an approach recognises that not all impediments to solar exports should be addressed by government, and even where there is a case for action, not all barriers can be addressed in such a way that the benefits will outweigh the costs.

8.2 Are there barriers to solar exports and solar export pricing?

Overall, the solar export market appears to be working reasonably well. Chapter 4 found that the market in SEQ provides multiple product offerings to consumers searching for feed-in tariff options. Further, the market includes a wide and growing range of services offered by incumbents and new entrants. These new business models can add value and gain market share where they help customers overcome impediments in the existing market, which should lead to additional uptake of solar PV systems.

This inquiry did not identify significant barriers to solar PV exports or solar export pricing. However, there are issues that may impact on the competitiveness of the solar export market:

- restrictions on trading solar exports;
- metering and tariff structures;
- network connection processes;
- information problems; and
- policy and regulatory barriers.

8.3 Restrictions on selling solar exports

In most markets, producers and consumers can trade with any party.

However, the current structure of the electricity market means solar PV owners generally buy electricity and sell solar exports through the one retailer. Under market arrangements, solar PV energy fed into the grid always has a 'buyer', and customers in SEQ can choose the retailer they sell to, but solar owners cannot trade their electricity in the market. They cannot sell directly to other consumers, and due to the costs of maintaining multiple trading relationships (where consumers can buy and sell energy through different retailers), consumers are likely to retain a single trading relationship with one retailer for the time being.

[177] CCIQ, sub. 21, p. 8.

Solar Citizens [178] noted that households without solar power may be willing to purchase energy directly from households with excess solar power — in effect, cutting out the retailer 'middleman'. In doing so, solar PV owners would receive a market price for their energy exports. Customers that see value in the environmental or 'other' benefits of clean energy may elect to pay a higher rate, which may allow the solar PV household to recoup a higher value for their energy.

However, the costs of establishing a market interface for small amounts of energy are prohibitive at present. The Australian Energy Market Commission (AEMC) recently decided against making a rule change to empower multiple trading relationships within the existing market structures. The reason for this decision was, in part, that the rule change was unlikely to deliver material benefits for most customers, but it was likely to impose significant costs on retailers and distributors that could result in increased electricity retail prices for all customers.[179]

8.4 Metering

How electricity is metered is an issue that impacts upon all electricity consumers, but it can also limit how solar PV owners are paid for the energy they export.

Some stakeholders indicated that metering is a barrier to distributed generation in Queensland. In its submission the Queensland Farmers Federation noted that:

> *Older-technology meters without interval recording capability are an impediment to facilitating the feed-in of excess energy generated from on-farm sources…*
>
> *…Any meters/metering products installed now must take into account future needs, and the quality and functionality of the (smart) meters must be of sufficient standard to permit the feed-in of excess electricity generation from solar to the local grid.*

John Sheehan stated:

> *It is archaic and costly that electricity meters are read manually via a site visit every quarter, rather than remotely based on a settlement period (e.g. 30 minutes, monthly). Current meters cannot provide real-time information to consumers about energy consumption (or rooftop generation – gross or net, or stored energy). Instead, a consumer must wait for a quarterly bill to arrive – too late to identify and react to a spike in energy use*[180]

Other stakeholders advocated for ‘local electricity trading’ or ‘virtual net metering’, where generation is netted off from one site at another site so that the distributed generator can ‘sell’ or assign generation to another consumer.[181]

The Queensland Government has committed to a voluntary, market-led rollout of smart meters in Queensland. This rollout is likely to be accomplished in SEQ with retail companies bundling the cost of smart meters into the retail electricity offers they make to electricity consumers.

The process for the rollout in regional Queensland is less clear. The Uniform Tariff Policy (UTP) effectively makes it unprofitable for retail companies to compete (and therefore to offer meter-bundled contracts) in regional Queensland.

Ergon Energy (Retail) is effectively prevented from offering advanced meters because it is unable to recoup its costs for those meters under Schedule 8 (Maximum fees payable to electricity entity) of the Electricity Regulation 2006.

[178] Solar Citizens, sub. 18, p. 8.
[179] AEMC 2015c.
[180] John Sheehan, sub. DR10, p. 2.
[181] University of Technology Sydney, Institute for Sustainable Futures 2015.

8.5 Time-of-export pricing

The cost of supplying electricity varies significantly depending on demand and supply, which varies across the day and season. However, the flat volumetric tariffs that apply to most residential households do not accurately reflect the cost of consumption or production of electricity at different times.

The 2008 COAG principles for feed-in tariff arrangements (updated in 2012) considered that export pricing should reflect the value of the energy to the market and the network, taking into account the time of day during which energy is exported. The AEMC has also recommended further consideration be given to time-of-export solar tariffs.[182]

Presently, no states and territories have market-based time-of-export pricing for solar PV.

In a 2014 submission to IPART, the Clean Energy Council highlighted the potential benefits of time-of-export pricing:

> *The days of incentive-based feed-in tariff offers are behind us. Australia's solar industry does not seek a return to the days of 1:1 feed-in tariffs. All we seek is the right to compete at a fair price. Competing at a fair price means that retailers should pay a benefit-reflective feed-in tariff. A benefit reflective feed-in tariff would be:*
>
> - *technology-neutral;*
> - *time-varying and would include a critical peak payment; and*
> - *(ideally) location-specific. …*
>
> *Aligning electricity prices and feed-in tariffs with the costs and benefits that customers generate will enable greater economic benefits from distributed generation. This will ultimately reduce costs for all customers and across the entire economy.*[183]

The Queensland Conservation Council noted that:

> *A rigorous time of day pricing regime which includes maximum demand incremental pricing inclusive of stand by power marginal cost allowances would be sufficient to provide sufficient incentive to the majority of the business community and more high income households to adopt both solar PV and better energy conservation practices.*[184]

To assess the potential impact of time-of-export pricing, we examined whether:

- solar PV owners receive less through flat compared to time-of-export tariffs; and
- time-of-export pricing would result in efficiency gains by providing incentives for solar PV owners to make efficient consumption and production choices.

8.5.1 Financial outcomes for solar PV owners – flat tariffs compared to time-of-export tariffs

Whether solar PV owners are better off overall under time-of-export pricing depends on a variety of factors, including in-house consumption, electricity tariffs, solar panel installation orientation and the impact on wholesale prices.

Submitters to the Solar Citizens' survey and email campaign suggested that they would support this style of tariff, with statements that broadly reflect a desire to receive the same payment that the generators get:

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[182] AEMC 2012, p. 239.
[183] CEC 2014b, pp. 1–2.
[184] Queensland Conservation Council, sub. 39, p. 6.

> *We are not being paid enough for the power we supply when there is high demand (when air-conditioning demand is high). Look at the prices that are charged at these peak times for comparison.* [185]

A simple comparison of flat feed-in tariffs available in the market compared to a time-of-export price based on the Queensland wholesale price, suggests that solar PV owners would not receive more under a time-varying market price.

As shown in Figure 53, using wholesale pool prices for Queensland in 2015–16 and the average solar generation profile, if a solar PV exporter was treated as a generator in the NEM they would earn 5.49c/kWh. The price would be higher in the afternoon (between 4 pm and 6 pm the price would average 10.36c/kWh), but as the wholesale price oscillates around 4c/kWh during the middle of the day, the price from 6 am to 4 pm would be 5.3c/kWh, producing an overall price of 5.49c/kWh.[186]

Figure 53: 2015–16 wholesale electricity prices

Note: 2015–16 wholesale price to 23 February 2016.

This is consistent with findings in New South Wales and Victoria. Modelling undertaken for New South Wales of a simple peak/off-peak solar tariff calculated a peak tariff of 6.1c/kWh (for 3 pm to 5 pm) and an all-other-times tariff of 4.7c/kWh — this is equivalent to a flat tariff of 5.1c/kWh.[187] In its draft report on the energy value of distributed generation, the ESC's proposed multi-rate feed-in tariff showed peak values between 5.1c/kWh and 7.0c/kWh and shoulder/off-peak prices of between 2.8c/kWh and 5.5c/kWh. In its report, the ESC noted that time-of-export tariffs resulted in similar returns as the single flat feed-in tariff:

> *This result is as expected. A multi-rate FiT is not expected to materially change the annual payoff received by a typical Victorian solar PV household when compared to the existing single flat-rate FiT. In some years, the annual pay off would be higher; in some years it would be lower.*

[185] Solar Citizens, sub. 18.
[186] As Solar PV owners cannot participate in the wholesale market, this comparison is for illustration purposes only. It excludes any costs of participating in the wholesale market, such as the costs of managing wholesale market risk that the generators undertake.
[187] IPART 2015.

> *The reason is that the weighting method applied when setting the flat rate FiT is designed to ensure that annual payments to a typical solar PV distributed generator are, in aggregate, a reasonable approximation of the wholesale market value of those exports. The multi-rate FiT model seeks to achieve the same result, but in a way that is not tied to a particular technology or to the export patterns of distributed generators.* [188]

To further examine the impact of tariff structures on the income of solar PV customers, we used a publicly available solar simulator/calculator[189] and AEMO wholesale market pricing data to model the financial outcomes for customers in scenarios that varied by location, panel orientation, and method for export pricing. To isolate the impact of solar exports, the analysis assumes a 100 per cent of solar generation is exported. A counterfactual was established by modelling the income under the existing pricing methodology for regional Queensland.

Over the past two years, the existing pricing methodology for regional Queensland (based upon an average wholesale cost of energy estimated in advance of the year to come) outperformed feed-in tariffs based on the wholesale electricity market price.

As shown in Table 29, each orientation and tariff structure creates significantly less income than the default north-oriented system receiving the feed-in tariff determined by the QCA. For example, when using the default (north) installation orientation, customers would be between 4.6 and 13.2 per cent worse off receiving the wholesale market value of electricity.

Different orientations provided different financial benefits to solar households depending on tariff structure and location over the two simulated years. However, under time-of-export pricing, overall income was not significantly different between north and west facing panels.

Table 29: Estimated annual income from solar PV

Year	*Location*	*QCA FiT (north orientation, default)*	*ToE market FiT (north orientation)*	*ToE market FiT (west orientation)*	*QCA FiT (west orientation*
2014	Brisbane	$282.00	$255.15 (–9.5%)	$262.92 (–6.8%)	$244.12 (–13.4%)
	Townsville	$295.07	$264.70 (–10.3%)	$265.51 (–10.0%)	$260.63 (–11.7%)
	Longreach	$324.80	$293.56 (–9.6%)	$291.17 (–10.4%)	$269.16 (–17.1%)
	Mt Isa	$322.68	$302.40 (–6.3%)	$302.12 (–6.4%)	$276.08 (–14.4%)
2015	Brisbane	$254.59	$222.57 (–12.6%)	$221.07 (–13.2%)	$220.71 –13.3%)
	Townsville	$266.75	$231.42 (–13.2%)	$221.95 (–16.8%)	$236.01 (–11.5%)
	Longreach	$292.51	$260.61 (–10.9%)	$251.90 (–13.9%)	$242.83 (–16.9%)
	Mt Isa	$289.98	$276.70 (–4.6%)	$279.60 (–3.6%)	$248.53 (–14.3%)

Notes: ToE — time-of-export. Model outputs are based on a PV system with a 3 kW inverter and 3 kW of solar panels. Tariffs are based on the wholesale cost of energy only and exclude line losses and NEM fees (that is, all tariffs are the wholesale cost of energy only, to enable a direct comparison). System orientations are optimised for summertime production at their geographic location.

Source: QPC calculations based upon wholesale prices from AEMO and solar generation estimates created at PVwatts.nrel.gov.

This analysis is static — it does not account for behavioural changes or their flow on impact on wholesale market and solar export pricing. As the assessment is focused on feed-in tariffs for solar PV, it also does not include an assessment of the potential impact of battery storage and time-of-

[188] ESC 2016.
[189] http://pvwatts.nrel.gov/.

export pricing. Even so, as the model assumes that 100 per cent of solar generation is exported, the income calculations are the maximum values that a household can extract by selling their energy to the market. As such, under any set of behavioural changes, solar investors are worse off under time-of-export pricing, unless wholesale market or network benefits — which would make all consumers better off — exceed the revenue loss.

8.5.2 Efficiency gains from time-of-export pricing

The primary benefit of time-of-export pricing is that efficient price signals drive efficiency gains in wholesale market and/or network infrastructure.

Existing solar PV owners cannot respond to time-of-export pricing and increase production to ameliorate wholesale market or network peaks — solar PV production is uncontrolled and intermittent. Hence, efficiency gains from time-of-export solar pricing would most likely come from indirectly effecting solar PV owners' *consumption* rather than *production*.

As noted by the Australian Energy Council, the impact of pricing on behaviour, and hence the potential for efficiency gains, is far greater through consumption pricing rather than solar export pricing:

> *More cost-reflective tariffs for electricity consumption would reveal the value of solar PV to customers far more effectively than government-mandated feed-in-tariffs. For example, if tariffs reflected the value of supplying electricity at peak demand periods, then customers who installed and used solar PV to reduce their peak demand would receive the benefit through lower tariffs.*[190]

That is, a time-varying consumption price would strengthen the incentive to alter overall consumption behaviour, which would encourage consumers to demand less and export more during peak times.

Consequently, it would be more effective and efficient to directly target consumption through cost-reflective tariffs (for all electricity consumers, not just solar PV owners), rather than indirectly through solar export pricing. Once battery storage becomes cost-effective, solar PV owners will have some control over production and will be better placed to respond to price signals.

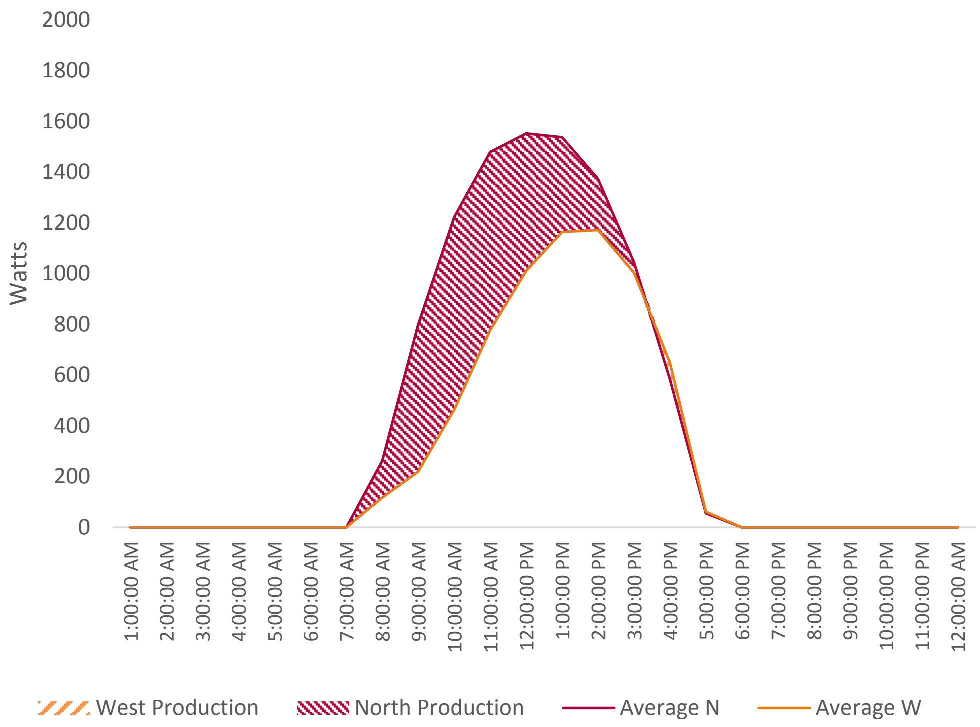
In terms of future solar PV installations, both the AEMC[191] and the Productivity Commission[192] have noted the potential for time-of-export pricing to encourage the installation of west-facing panels, thereby more closely aligning solar generation with network peak demand and wholesale energy price peaks.

Pricing outcomes modelled in Table 29 indicate that time-of-export pricing based on wholesale prices alone may not be sufficient to incentivise the installation of west-facing panels. If an additional payment was required to provide a sufficient incentive, it would need to be supported by robust evidence that west-facing panels reduce the network peak and translate into savings.

Figure 54 and Figure 55 show average daily outputs in the winter and summer for west-facing panels. In the winter, west-facing panels significantly reduce overall production, with no change in the afternoon. In the summer, west-facing panels shift solar generation later in the afternoon, but the increase in the early evening (typically residential peak) is small, and generation ends at roughly the same time as north-facing panels.

[190] AEC, sub. DR9, p. 2.
[191] AEMC 2014b.
[192] PC 2013.

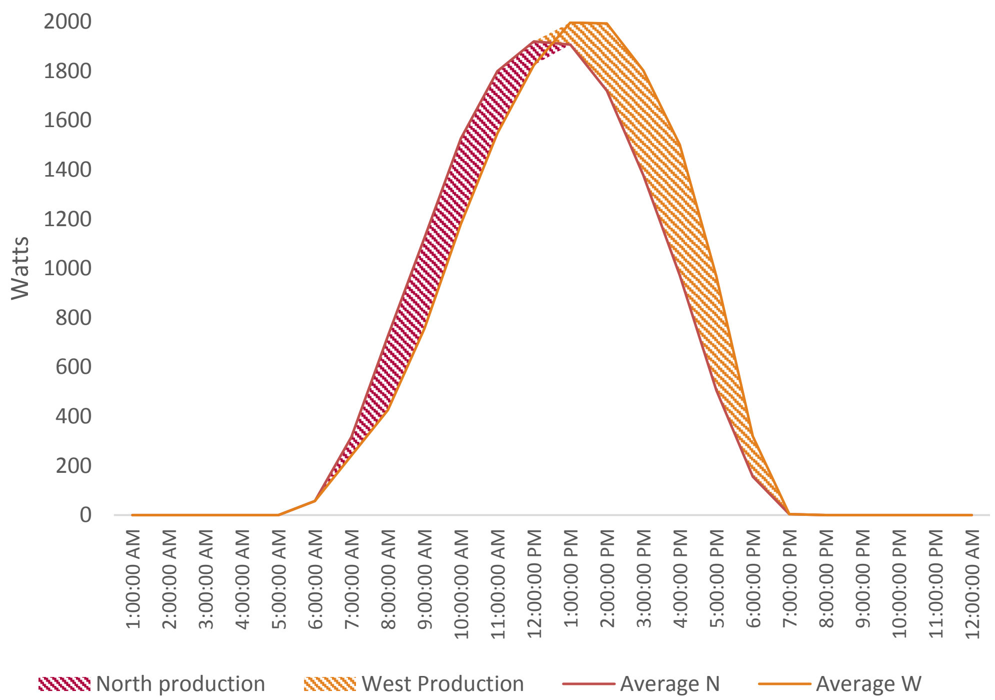
Figure 54: Daily PV outputs in Brisbane in June with different installation orientations



Note: West production marginally outstrips north production between 4 and 6 pm. Due to the limited difference (35 watts/hour on average) it can be difficult to visually observe.

Source: QPC calculations. Solar generation estimates created at PVwatts.nrel.gov.

Figure 55: Daily PV outputs in Brisbane in December with different installation orientations

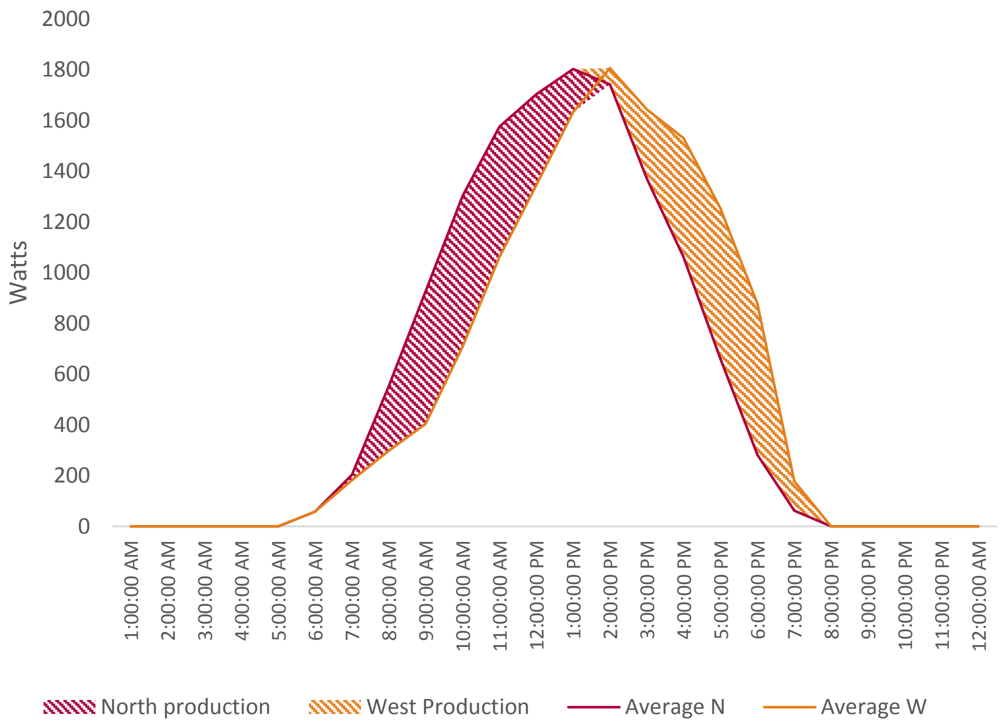


Source: QPC calculations. Solar generation estimates created at PVwatts.nrel.gov.

A west-oriented installation in Brisbane contributes some additional generation on summer afternoons and minor additional generation during the 5 pm to 7 pm window when many peak load events occur. The simulation suggests that west-facing panels contribute an additional 15 per cent of capacity at 5 pm, falling to five per cent at 6 pm, and to zero at 7 pm. [193]

The shift in generation from west-facing panels may be more pronounced in southern states, where at higher latitudes and with daylight saving, solar PV could continue generating later into the day. For example, the simulated output for a similar system installed in Melbourne is shown in Figure 56. Although both the north- and west-oriented systems are less productive in total than their Queensland comparators, the west-oriented Melbourne system offers a greater afternoon benefit than a north-oriented system, and this benefit extends to the early evening hours. The simulation suggests that in Melbourne the 'orientation contribution' amounts to an additional 20 per cent of capacity at 5 pm, and another 20 per cent of capacity at 6 pm, before falling to four per cent at 7 pm.

Figure 56: Daily PV outputs in Melbourne in December with different installation orientations



Note: Figure 55 and Figure 56 exhibit some graphical clipping where west and north production intersect because the inversion point occurs mid-hour; where this occurs refer to the line series rather than the pattern-filled areas.

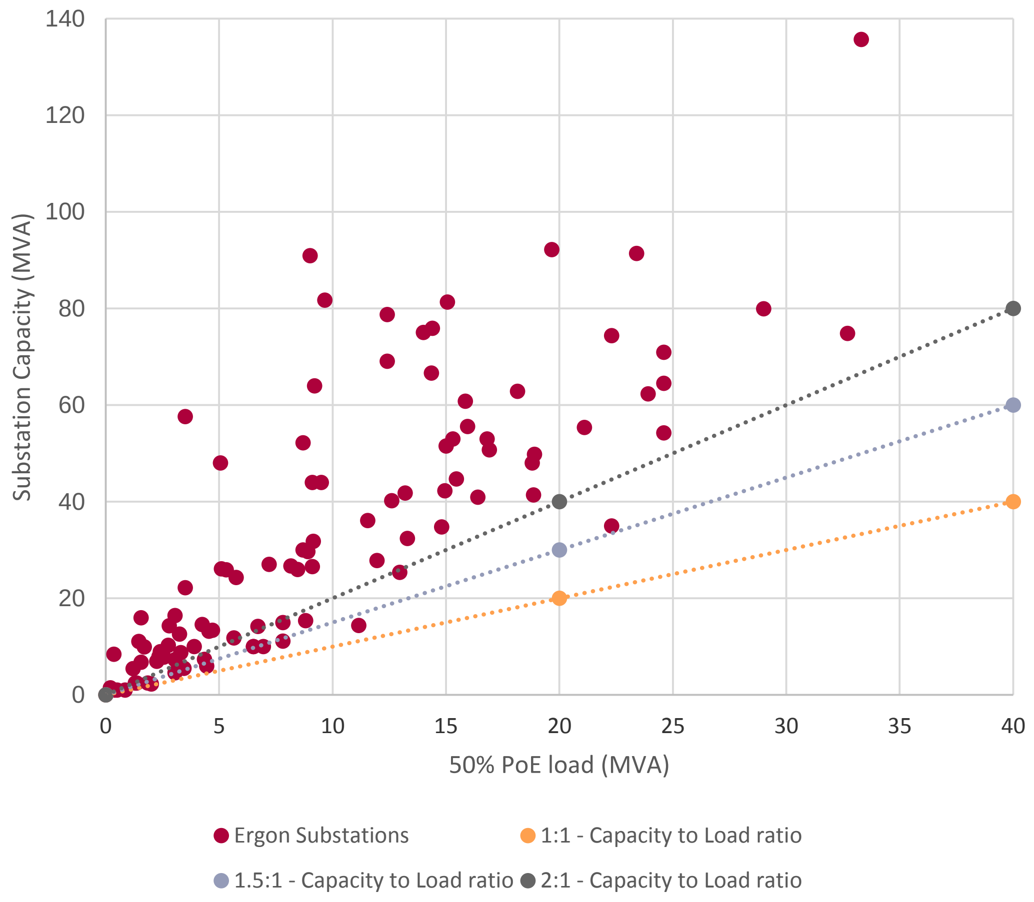
Source: QPC calculations. Solar generation estimates created at PVwatts.nrel.gov.

Consistent with the findings in Chapter 6, for west-facing panels to deliver network 'benefits' they must more closely align solar PV generation with network peak demand *and* this then must delay network investment. The PV generation model developed above identified time periods where west-oriented installations offered production advantages over a north installation. As demonstrated in Figure 54 and Figure 55, these time periods vary seasonally. Specific periods for each month of the year were compared with observed network peaks in Ergon substations.

[193]The increase in generation is from a low base. West panels out-produce north panels by 460 watts per hour (5–6pm) and 165 watts per hour (6–7 pm).

To answer the question of whether west-facing panels are likely to reduce peak demand, a high-level analysis of Ergon substation capacity was conducted (using each substation's normal cyclic capacity (NCC)) and expected load (50 per cent Probability of Exceedance (PoE) load and 10 per cent PoE load). Of the 255 substations examined, 100 had a historical peak load event that occurred during a time window that may have been assisted with a west-oriented panel system — that is, the peak may have been lower if west-oriented panels were installed. However, of these substations there appear to be very few requiring augmentation to meet load over the next regulatory period. A majority of the substations examined have a greater than 2:1 ratio of capacity to expected load — they have more than double the capacity they currently need (Figure 57).

Figure 57: Substation capacity constraints – 50% PoE load



Notes: The figure depicts only those substations which have a peak load that would benefit from west-oriented panel system. PoE — Probability of Exceedance. Ergon typically compares NCC with the 50 per cent PoE load. Comparing the NCC figures to the 10 per cent PoE load forecasts obtains a similar result as shown in Figure 57.

Source: QPC calculations based on Ergon substation data.

Of the substations that could potentially benefit, 19 substations out of 255 have both a historical peak that could be ameliorated by west-oriented installations and less than double the capacity they require. That said, only one substation out of 255 is estimated to fail the security standard over the next planning period, and its historical peak occurred at dusk, when even west-oriented solar PV installations would be of little benefit.

8.5.3 Summary

As is the case for electricity pricing more broadly, time-of-export pricing has the potential to result in efficiency gains. However, these gains may not be as significant as first expected, and are likely to be small in comparison to time-varying pricing for electricity consumption. To achieve overall efficiency gains and avoid unintended consequences, time-of-export pricing would likely need to be accompanied by time-varying consumption and demand tariffs. As the AEMC noted:

> *[I]t is important that the combination of both the feed-in tariff and the consumer's own retail tariff should be providing the right efficiency signals.*[194]

It would also be counterproductive to consider any additional time-varying payment for solar PV while non-reflective network tariffs remain, whereby non-solar PV customers subsidise the network charges for a solar PV customer by $120 per year.[195]

In relation to network benefits from time-of-export pricing, even if augmentation deferral was possible and required, the use of a broad-based feed-in tariff delivered to every customer is unlikely to be the most cost-effective way of incentivising micro-embedded generation investment to address specific constraints.

Overall, there is no compelling case for the Queensland Government to intervene to introduce time-of-export pricing. As noted in Chapter 3, pricing imperfections do not provide a basis for government to regulate prices:

> *At the end of the day, therefore, there is a trade-off between living with imperfect regulation or with imperfect markets. It is only when the market does not work well, when there is a clear case of natural monopoly and when regulation can reasonably be expected to improve matters that the regulatory option is worthwhile. Market imperfections alone are not a sufficient justification for intervention.*[196]

There is no restriction on time-of-export pricing for solar PV exports (although the absence of advanced meters may be an impediment). As such, time-varying solar pricing should occur in the market where it is beneficial and the broader electricity market evolves to accommodate it.

8.6 The potential to exercise market power through denying connection

Solar PV owners require approval from Ergon Energy (Network) or Energex to connect a solar PV system to either of their networks. A very effective way to exercise market power would be for Energex or Ergon Energy to deny these requests. In the case of regional areas, permission for connection is granted by Ergon Energy Corporation (the network arm), not Ergon Energy Queensland (the retail arm).

A connection application that is rejected based on a desire to protect network or electricity sale revenues, rather than based on reasonable engineering and safety considerations, would be evidence of the exercise of market power.

In SEQ, there is full structural separation between the distribution company (Energex) and electricity retailers. Connecting additional solar PV systems will reduce the revenues of the retailers, but not necessarily Energex as a regulated DNSP, at least not in the short term. In Queensland, generators are structurally separate from distributors (although there is a common shareholder for the government-owned entities), so distributors should not have an incentive to limit the uptake of solar PV systems in order to protect the revenues of the generators. In the longer term, however, solar PV may impact network revenues and, as such, may be viewed as a competitor to network businesses.

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[194] AEMC 2012, p. 241.
[195] AEMC 2014b.
[196] Starkie 2008, p. 136.

In the case of Ergon Energy, the business is both a distributor and an electricity retailer. Both entities report through the same company board and have the Queensland Government as owner. Below board level, ring-fencing arrangements are in place.[197] However, despite the ring-fencing arrangements, it is unlikely that Ergon Energy as a network entity is indifferent to the future revenue streams of Ergon Energy (Retail).

Energex and Ergon Energy have developed a connection standard for small-scale inverter energy systems (IESs), including solar PV systems (Box 22). Permission to connect may or may not be granted, depending on compliance with the various conditions covered in the connection standard.

Box 22: Requirements to connect a solar PV system to the electricity network

In July 2014, a new connection standard for small-scale inverter energy systems (IESs) up to 30 kVA, which includes rooftop solar PV systems, was introduced. This was a joint initiative between Energex and Ergon Energy.

The objective of the standard is to provide IES proponents with information about their obligations for connection to, and interfacing with, the Ergon Energy or Energex networks. When connected to the network, an IES can impact the operating conditions, voltage profile and feeder load. As such, any IES operated 'on-grid' is required to enter into an IES Connection Agreement or Standing Order in order to operate.

Under the Electricity Regulations 2006, all new and additions to existing IES require an application for approval to connect to the network. Failure to receive approval prior to installation may involve extra costs for the customer and installer. The system may have to be turned off, or reduced in capacity or removed completely. Installers are required to sight the IES Network Connection Agreement before commencing installation.

Under the connection standard:

- technical assessments are required for systems above 5 kVA that intend to export energy to the grid;
- connection to the network can be made without an engineering assessment if the system:
  - is up to 2 kVA within the Ergon Energy (non-isolated) supply network (and 3 kVA within the Energex supply network), and have AS4777 compliant inverters;
  - is between 2 and 3.5 kVA within the Ergon Energy (non-SWER and non-isolated) supply network (and 3 to 5 kVA within the Energex supply network) if there is zero net export to the grid, or if there is a positive net export and the inverter is AS4777 compliant and includes a variable power factor setting fixed to 0.9 lagging (that is, inverter imports reactive power); and
- for 3.5 to 5 kVA systems in the Ergon Energy (non-SWER and non-isolated) supply network, a technical assessment is required.

Should a proposed installation not pass an assessment, the applicant can:

- reduce the size of the inverter;
- install an approved power limiting device; and
- request a more detailed assessment.

Source: Ergon Energy Corporation 2014.

Some applications for connection are rejected for legitimate engineering and safety reasons. However, there is also scope for differences of opinion on what constitutes a reasonable basis for rejection based on engineering and safety issues.

A number of stakeholders raised issues with the grid connection processes that are enforced by the two distribution businesses. Some consumers and businesses in the electricity supply chain were concerned that the distribution businesses essentially have the power to use the connection processes as veto against alternative technologies such as distributed generation and energy

[197] For a discussion of the ring-fencing arrangements see QPC 2016a, p. 248.

storage that compete with the distribution businesses. Others were concerned about the time, expense and difficulty of getting connections approved:

> *Network businesses currently have the authority to approve or reject the grid connection of distributed generation solutions sought by consumers, and at times this process lack transparency and create delays and barriers to uptake.* [198]
>
> *One of the major barriers to the solar export market is the ability to enter into a grid connection agreement with the relevant distribution company. At present there is little regulation in this area and each agreement is negotiated on a case-by-case basis.*
>
> *This is most prevalent in the commercial/industrial scale system size and due to the low levels of deployment at this scale to date, there have been few opportunities to overcome the perceived problems.* [199]
>
> *APA is very aware that barriers relating to potential connection to the electricity network … still exist. This applies not only to solar equipment, but also for other potential low emission FiT technologies … Typical issues in relation to barriers to connection are:*
>
> - *an inability to gain easy connection to the electricity network;*
> - *issues with obtaining planning permits to construct local infrastructure networks;*
> - *issues that relate to information asymmetry.*[200]

In its response to the Draft Report, AGL again raised:

> *serious concerns with the connection standard and assessment process implemented by Energex Ltd and Ergon Energy for micro embedded generation connections. AGL supports the Power of Choice reforms across the NEM and encourages the Queensland Government to play an active role in progressing harmonisation of the grid connection process.*[201]

That said, Ergon Energy has submitted that it has connected 110,000 solar PV systems to its network and that its connection processes are functioning smoothly (Box 23). The QPC has not received evidence contradicting these claims for small-scale solar PV system connections. Some concerns have been expressed by stakeholders concerning the connection of larger-scale solar systems and systems for business customers.[202]

198 AGL, sub. 19, p. 5.
199 University of Queensland, Global Change Institute, sub. 28, p. 12.
200 APA Group, sub. 26, pp. 6–7.
201 AGL, sub. DR14, p. 2.
202 John Sheehan, sub. DR10, p. 3.

Box 23: Improved connection processes

Ergon Energy has facilitated the connection of more than 110,000 solar PV systems to its network. Ergon Energy has invested heavily to assist customers with the approval and connection of solar PV, with the majority of solar applications processed within 24 hours and notification returned to the customer within five working days.

To facilitate the adoption of solar PV units, Ergon Energy has introduced an online application process for new solar PV unit connections and has a dedicated solar support team resourced to assess and provide network agreement to approved applications.

To improve engagement with both solar customers and PV retailers/installers, Ergon Energy has led active engagement through establishing its 'micro embedded generating unit' Industry Working Group, which holds quarterly sessions with key partners from the Queensland solar industry including the Australian Solar Council, Clean Energy Council, Department of Energy and Water Supply, and Energex.

Engagement with the PV industry has also been increased through the PV Industry Alerts information notifications regularly issued by Ergon Energy and the Residential Electrical Contractor Engagement Sessions (RECESS) Forums being conducted across regional Queensland for electrical contractors/solar installers and provide an opportunity for two-way collaboration with Ergon Energy.

Source: Ergon Energy Corporation, sub. 34, pp. 14–15.

The connection standard allows for connection without a technical assessment for smaller solar PV systems, although Ergon and Energex differ on the size of systems which may be connected without a manual technical assessment.[203] The need for a technical assessment is expected to be more frequent going forward due to increases in the average system size of household solar PV systems and rising solar PV penetration levels which cause various network reliability issues (discussed in Chapter 6).

Australian solar PV system installers were surveyed on whether they commonly encountered difficulties with obtaining approval to connect to the network:

> *Many respondents advised of little-to-no difficulty obtaining network connection approval. This seemed to be the case particularly for residential, though there are circumstances where the customer cannot put on the system size they want. Commercial PV was more problematic, particularly where there was a myriad of nuanced connection rules subjectively interpreted by DNSP. There were also complaints of overly onerous requirements and long approval timeframes.*[204]

Overall, the potential exercise of market power by limiting the ability to connect to the network does not appear to have limited solar PV uptake to date. So long as people can connect their solar PV systems to the network, facing only the legitimate costs of connection based on reasonable assessments of the risk to the network from their connection, then investment in solar PV will continue to occur.

8.7 Information asymmetries

As discussed in Chapter 3, markets work well when buyers and sellers have sufficient information to make informed decisions. Information can be important in more complex markets such as solar PV exports, which require material up-front investment and interact with the electricity market more broadly:

[203] Ergon & Energex, Small Scale Parallel Inverter Energy Systems up to 30 kVA, accessed 04 May 2016.
[204] Johnston 2014, p. 3.

The only way a long term, properly informed and balanced market can be achieved is through conducting ongoing, effective education campaigns backed up with frequent, transparent market research and analysis.[205]

The most common barriers cited in submissions were information problems associated with how the electricity market worked, financial returns on solar PV installations, the impact of feed-in tariffs; and the information asymmetries between large retail or network companies and individual electricity consumers.[206] Some stakeholders[207] said information asymmetries impede the ability of individual customers to negotiate a 'fair' feed-in tariff from their retail company.

A wide variety of consumer information on solar PV and solar export pricing is available:

- Multiple price comparator websites can be accessed, for example, the AER-supported energymadeeasy.gov.au, and the solar industry run solarchoice.net.au.
- Solar PV payback calculators estimate likely payback periods and help customers to estimate the size of system they need. Calculators are available from many industry sites, including solarchoice.net.au. There are also websites for solar brokerage firms that offer these calculator services, like solarmarket.com.au and PV simulators like pvwatts.nrel.gov which allow customers to simulate system sizes and orientation to determine appropriate sizes and configurations.
- CHOICE has published information about solar PV paybacks in simple-to-read language. AGL, too, provides a system that helps households to estimate their usage and the system size that they need.
- In Queensland and interstate, regulators provide information to households through decisions and other activities on solar PV and feed-in tariffs; for example, in New South Wales, IPART publishes a benchmark range of feed-in tariffs for solar energy each year.
- The Clean Energy Council (CEC), the national peak body for the solar industry, also provides a substantial amount of information including purchasing and installation guidelines, as well as lists of certified installers and components to help customers ensure they are getting high quality merchandise from a reputable dealer.

However, there is evidence that for some small energy consumers, including vulnerable and disadvantaged consumers, understanding and negotiating a complex investment decision and searching for the optimal feed-in tariff arrangement presents a challenge. For example, as discussed in Chapter 4, due to the link with retail electricity purchase, some customers may be better off overall with no feed-in tariff but a lower retail electricity price.

Some respondents felt that their investments have not lived up to their expectations or that they have been misled about the benefits of solar:

I invested $5000 to have the solar panels of 5kw. REALITY I am being charged 22+ cents for the power used for my house, when I have produced 100% of the product… I would prefer to return to my pre solar days … I am not prepared to be RIPPED OFF.[208]

I am on 6 c per KW feed in tariff and recently had a faulty inverter replaced out of warranty. With such a low feed in tariff it would take several years to just pay off the repaired/ replaced system.[209]

[205] David Warner, sub. 13, p. 2.
[206] Michael Mokhtarani, sub. 4, p. 1.
[207] Australian Solar Council, sub. 38, p. 3; Don Willis, sub. 17, p. 7.
[208] Harold Turnbull, sub. 1, p. 1.
[209] Ernest Priddle, sub. 5, p. 1.

> *In October of 2014 I received advertising with my Origin electricity account for solar, I inquired with Origin and the sales rep stated that based on my bill at the time I could save up to $300 a quarter. So at a cost of $4000 I agreed to have them install, this has proven to be a huge error.*
>
> *The system is a 3kW [receives maximum sunlight] and to date has only managed to produce about $70 a quarter with the rebate price of just 6 cents.*[210]

Recently, the Australian Competition and Consumer Commission (ACCC) investigated a solar company for offering customers incentives to provide unbalanced positive reviews on an online product review platform, with the ACCC Deputy Chair, Dr Michael Schaper, stating:

> *Businesses that offer incentives for unbalanced positive reviews risk misleading consumers and breaching the Australian Consumer Law.*[211]

Others noted widespread perceptions, largely fuelled by returns achieved under the 44c/kWh scheme, that feed-in tariffs are the primary financial benefit of solar PV, that a solar PV installation would mean 'they would never pay for electricity again' or that an investment return was essentially guaranteed by government:

> *I believe the government has a responsibility to continue to support those who were encouraged into the solar market as a direct result of their policies.*[212]

And others demonstrated that there are still misunderstandings in the community about how the SBS is funded:

> *I thought that the 'green' power/electricity exported to the grid at 0.44 cents/kW was then on-sold at a much higher rate to businesses who were obliged to buy green power to offset their 'dirty'/polluting business practices!*[213]

Similar perceptions were evident in the Solar Citizens' campaign (Box 24). There appears to be some confusion around wholesale and retail electricity prices, the financial benefits of solar PV and the degree to which electricity prices in regional Queensland are subsidised by the Queensland Government through the UTP. For example, some solar PV owners indicated that retailers should 'pay solar owners the same price it pays fossil fuel generators', but feed-in tariffs based on the wholesale price do pay solar PV owners the same price paid to fossil fuel generators.

[210] Stephen Read, sub. 43, p. 1.
[211] ACCC 2016.
[212] Julie Davies, sub. 14, p. 1.
[213] Frank Ondrus, sub. 7, p. 1.

Box 24: Fair Price for Solar Campaign

In April 2016, Solar Citizens launched a 'Fair Price for Solar' campaign generating more than more than 800 emails from members seeking a higher price for their solar exports. Key themes raised by Solar Citizens were the environmental benefits that solar PV offers, the way that their investment had helped to displace investment in network and generation infrastructure, and the unfair nature of a feed-in tariff which does not match the retail price paid for electricity.

Solar Citizens indicated that:

> *Solar households get 6c/kWh on average for power they generate. This very same power is sold to their neighbours at three times the price by big power companies. That's around 12c/kWh that power companies are withholding from solar owners.*

Many of the Solar Citizens supported a feed-in tariff that was equivalent to the retail price for electricity, and did not see any grounds for a difference between the two:

> *What is the difference between the power solar generates to that of a power station? Nothing! So why is the price per KW different?*

> *It is fundamentally unfair for the electricity retailers of Queensland to benefit from the windfall of 'free' or nearly free electricity handed to them via the artificially low feed-in price*

Some believed that the 44 cent feed-in tariff had led to others being disadvantaged.

> *We are only getting 6.3 cents per kWh and Ergon is reselling for about 22 cents, I think that they take as much as they can off us, in order to make up their shortfall with people being paid the absurd sum of 44 cents per kWh.*

Others felt frustrated by the lack of competition for the purchase of their energy in regional Queensland and felt that they were disadvantaged as a result.

> *I live in Far north Qld and we get NO CHOICE in our electricity supplier unlike our southern neighbours. I can't shop around for a better deal, because there is no better deal. Ergon could pay me 1c a kw and I could do nothing about it.*

Source: Solar Citizens, sub. DR24.

Confusion over wholesale and retail prices is not uncommon in other markets. For example, consumers sometimes express sentiment that a supermarket or restaurant should sell produce to customers at the wholesale price (the price paid to farmers and suppliers). But this ignores the cost of rent, transport and labour in retailing these items, just as the retail price for electricity includes network and retailing costs unrelated to generation (see Chapter 3).

On balance, some information problems are apparent in the solar market, but they are not larger than could be expected considering the level of complexity of the transactions involved. They are also comparable to those in markets for similar goods and services, and the broader electricity market. Even so, the persistent misconceptions on electricity pricing, legacy issues from the SBS and value of solar investments point to an ongoing role for regulators, peak bodies and government in educating consumers on the solar PV market, including ensuring information is accessible for vulnerable and disadvantaged consumers.

The role of and options for consumer education is considered in the Final Report of the QPC's Electricity Pricing Inquiry.

8.8 Policy and regulatory issues

8.8.1 Policy design

A number of submissions noted that the current renewable energy policy settings, which almost exclusively focus on rooftop PV, may have prevented lower-cost options from entering the market.

There is a 'natural limit' on the amount of rooftop solar PV — there are approximately 1.4 million separate house dwellings in Queensland, with a further 74,000 semi-detached single storey row or townhouses, which suggest a total 'available market' of around 1.5 million rooftops. As 29 per cent of dwellings are excluded, due to their tenure (they are rented), the total available market may be only 1.065 million rooftops.

Some submissions argued that more favourable treatment of rooftop solar for property owners has locked out potentially more cost-effective options. For example, households and businesses in rental accommodation, body corporates, leased sites and retirement villages were all prevented from accessing feed-in tariffs in Queensland due to their site tenure. [214]

Similarly, the University of Queensland Global Change Institute argued:

> *There is reason to believe that investment in commercial scale solar PV is at a sub-optimal level. There are a number of potential advantages with commercial based investments over residential investments. First, scale economies can arise whereby the ($/Wp) installation costs for commercial systems are often lower than equivalent costs for smaller capacity residential based systems … When Levelised Cost of Energy (LCOE) analysis is undertaken, the levelised costs of commercial sized systems tend to be lower, in part, reflecting the lower installation costs.* [215]

Others stated that the focus on rooftop solar resulted in overinvestment in solar PV at the expense of alternative low-carbon technologies and energy sources:

> *The subsidies provided to consumers relating to solar PV installations disadvantages the broader energy industry and provides a barrier to entry regarding further innovation of low carbon technologies and energy sources. By subsidising consumers' solar PV installations, the solar FiT scheme is potentially hindering future development of alternative low carbon technologies. This is an inherent problem when policy directs (rather than facilitates) the manner by which a particular government objective is achieved.*[216]

Feed-in tariff policy also has flow-on impacts to other markets. For example, higher feed-in tariffs may reduce the incentives to invest in storage solutions. A higher feed-in tariff, which reduces the gap between the variable component of the retail tariff and the feed-in tariff, reduces the incentive to augment an existing solar PV system with a storage system. It also reduces the incentives to invest in storage when purchasing a new solar PV system.[217]

In contrast, a lower feed-in tariff (for example, a feed-in tariff below the market rate) decreases the financial returns from exporting, but increases the financial incentives to invest in a storage system in order to reduce imports from the grid.

Under the existing regulated reference tariff (Tariff 11), the savings (or financial incentive) from reducing exports by one kilowatt hour for own-consumption (reducing imports from the grid) is between 12–16 cents for customers on Tariff 11. However, if a regulator imposed a mandatory feed-in tariff of, say, 15 cents, then the financial return from investing in storage to reduce exports is much lower at 7 cents per kilowatt hour for those on Tariff 11 (Table 30).

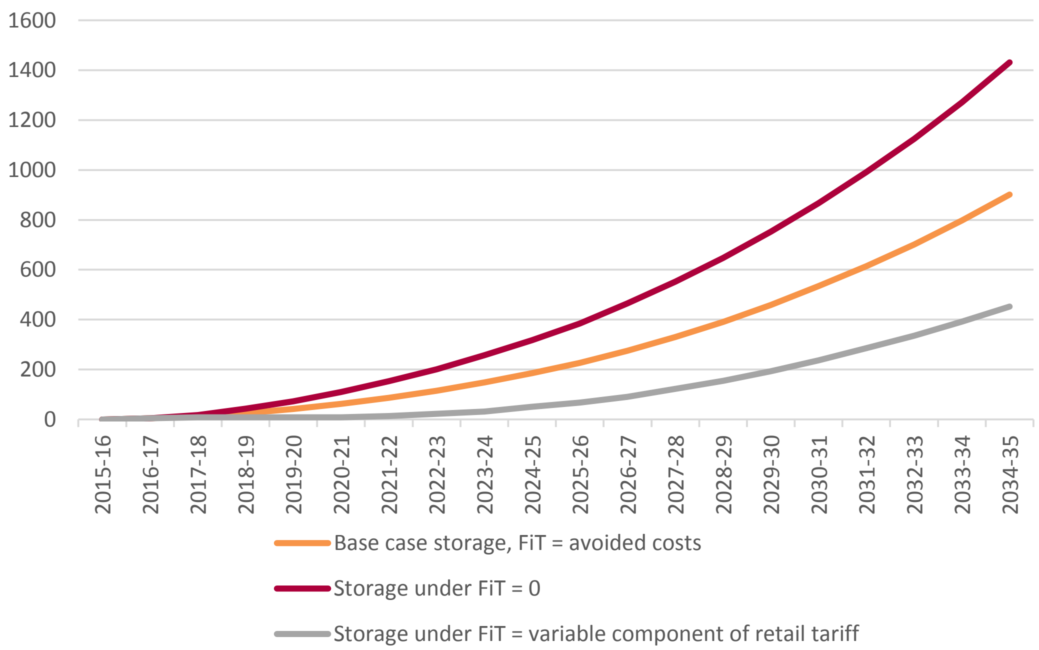
[214] AGL, sub. 19, p. 5.
[215] University of Queensland, Global Change Institute, sub. 28, p. 3.
[216] Australian Gas Networks, sub. 36, p. 6.
[217] This assumes that the feed-in tariff is less than the retail tariff. With feed-in tariffs above the retail rate, at some point it will become profitable to charge batteries from grid electricity and export energy back into the grid for the feed-in tariff.

Table 30: Regulation to increase feed-in tariffs reduce incentives to invest in storage

	Retail tariff - variable component (c/kWh)	*Feed-in tariff (c/kWh)*	*Incentive to reduce exports (c/kWh)*
Reference Tariff 11	22	6–10	12–16
Hypothetical regulated feed-in tariff	22	15	7

The modelled up-take of storage shows how the incentives to invest in storage change under different feed-in tariff levels (leading to differences in the size of the gap between the feed-in tariff and variable component of the retail tariff). Under the base case, where the feed-in tariff is equal to avoided costs, storage is projected to be roughly 900 MWh by 2034–35 (Figure 58). Where a feed-in tariff was not paid (that is, set to zero), storage up-take increases by almost 60 per cent to 1430 MWh. In contrast, where the feed-in tariff is set above market rates and equal to the variable component of the retail tariff, then investment in storage is suppressed, decreasing by 50 per cent to 450 MWh.

Figure 58 Projected storage investment under different feed-in tariff scenarios



Source: ACIL Allen 2015.

This suggests that, going forward, the Government should ensure that any policy settings do not provide more favourable treatment to specific types of a single technology. This should ensure that where alternatives are cost effective, including commercial solar, community solar and other low emissions technologies, they are not impeded by government policies. It will also avoid flow-on and distortionary effects in other markets, such as energy storage.

8.8.2 The Uniform Tariff Policy and solar PV

The UTP is designed to ensure that non-market residential and small business customers pay no more for their electricity, regardless of their geographic location. In practice, this means that regulated electricity prices for regional Queensland are set based on the costs of supplying the same class of customer in SEQ (for small customers) or in Ergon's Eastern zone (for large customers), rather than the actual costs of supplying these customers.

As the revenue Ergon Energy (Retail) receives from regulated prices is lower than its actual costs of supplying electricity in regional Queensland, the Queensland Government provides Ergon Energy (Retail) with an offsetting Community Service Obligation (CSO) payment.[218]The average cost of supply in Ergon Energy's east and west zones is about 30 per cent and 140 per cent greater than the average cost of supply in SEQ. The cost of providing this subsidy was approximately $596 million in 2014–15.[219]

As discussed in Chapter 2, the principal economic benefit provided by a net metered solar PV is the avoided costs of importing electricity — the electricity that a household or business does not have to buy from their retailer because they have generated it themselves. This benefit is dependent on the price of electricity — the higher the price, the greater the value of self-generation, and hence, the greater the value of solar PV generation. The UTP therefore dampens incentives to invest in solar because it significantly lowers the retail electricity price to consumers in regional areas. If the UTP was not in place then the incentives to invest in solar in regional areas would be much stronger.

Table 31 demonstrates the differences in the internal rate of return and payback period for solar installations in Ergon's east and west regions if the UTP was removed. In the case of a 5.0 kW system in the east zone, the internal rate of return would increase from 14.4 per cent to 18.1 per cent, with the payback period under a 6 per cent discount rate dropping from roughly nine years to seven years. For a customer in the west zone the financial impacts are more dramatic with the internal rate of return increasing to 38 per cent and the payback around three years.

Table 31: Financial returns to solar investment under relaxation of the UTP

	IRR	*Break-even (years) and difference in average cost of consumption (c/kWh)*							
	(%)	*d.r. = 0%*		*d.r. = 3%*		*d.r. = 6%*		*d.r. = 9%*	
3.0 kW system									
Base case	13.3%	7 yrs	–7.8c	8 yrs	–5.3c	10 yrs	–3.6c	12 yrs	–2.4c
East zone	18.1%	6 yrs	–10.9c	6 yrs	–7.7c	7 yrs	–5.4c	8 yrs	–3.9c
West zone	38.8%	3 yrs	–22.2c	3 yrs	–16.1c	3 yrs	–12.1c	3 yrs	–9.2c
5.0 kW system									
Base case	14.4%	7 yrs	–11.4c	8 yrs	–7.9c	9 yrs	–5.6c	11 yrs	–3.9c
East zone	18.1%	6 yrs	–15.7c	6 yrs	–11.1c	7 yrs	–8.1c	8 yrs	–5.9c
West zone	37.7%	3 yrs	–30.9c	3 yrs	–22.7c	3 yrs	–17.1c	4 yrs	–13.2c

Notes: IRR is the Internal Rate of Return. The above calculations are based on a partial-equilibrium analysis. Over time, removal of the UTP would lead to other changes in the electricity supply industry that would impact on the underlying assumptions used in the calculations. Calculations assume base case export rates, but, given the stronger incentive to adjust consumption to minimise exports, lower exports would likely be achieved which raise the internal rate of return and lower payback periods further.

Source: QPC calculations.

[218] QPC 2016a, p. 230.
[219] QPC 2016a, p. 225.

The calculations assume export rates of 45 per cent for a 3.0 kW system and 55 per cent for a 5.0 kW system, as observed in the market. However, the hypothetical removal of the UTP would result in increased retail electricity prices, further incentivising solar households to alter their consumption patterns so that less of the energy they produce is exported. To the extent they are able to alter their consumption patterns, the financial benefits would be even larger as more energy imports from the grid would be avoided. On the other hand, removing the UTP would have broader impacts that might diminish some of the financial gains to solar, as suppliers may extract some of these gains by raising system purchase and installation prices.

These impacts are theoretical; the Queensland Government is committed to retaining the UTP as discussed in the QPC's Electricity Pricing Inquiry Final Report.

8.8.3 Regulation

Regulation of solar PV occurs through a mix of federal and state regulation and industry standards. It includes federal legislation in the *Renewable Energy (Electricity) Act 2000*, state-based feed-in tariff regulation in the *Electricity Act 1994* and Electricity Regulation 2006. In addition, the CEC provides designer, installer, and component accreditation schemes, as well as a code of conduct. While these schemes are not compulsory to install a PV system, to claim the STCs under the SRES for a given system, both the designer and the installer must be accredited.[220]

Some regulation is necessary for a well-functioning electricity and solar PV market. Regulation helps establish the architecture for electricity markets to operate and can address both health and safety, and environmental issues. But even where there is a strong case for regulation, unnecessary barriers can arise where regulations are not the minimum required to meet those objectives.

Project Brainstorm[221] argued there were two main regulatory barriers to solar exports: restrictions on electricity charges in residential parks and retirement villages, and restricting entry to PV installation accreditation to individuals with a Queensland electrical licence:

> *[W]e have several potential clients (owners of retirement villages) who would like to invest in solar systems for their aged retirement tenants but are prohibited from charging a margin on electricity they provide their tenants.*

Regulation of the solar PV industry and solar exports have not been reviewed as part of this inquiry. When they are next reviewed, the Queensland Government should ensure that any regulatory prohibitions and barriers to entry are the best, or only, way of achieving the government's regulatory objectives for health and safety, and for consumer protection.

[220] CEC Solar Accreditation, see https://www.solaraccreditation.com.au/consumers.html.
[221] Project Brainstorm, sub. 11, p. 1.

Findings

8.1 There is no evidence of widespread or major barriers to solar PV investment and solar export pricing. That said, some factors can affect the competitiveness of the market:

(a) Trading of solar exports is generally tied to the purchase of retail electricity.

(b) Metering and tariff structures can limit efficient solar export pricing based on the time of export.

(c) Information problems may inhibit consumer decision-making.

(d) Policy design issues can distort efficient investment and impede the uptake of solar PV in regional Queensland.

8.2 There is no evidence to indicate that Ergon Energy and Energex are using their market power to systematically prevent distributed generation from connecting to the network. Nevertheless, distributed generators should be connected to the network in the most transparent, straightforward and timely manner possible.

9 REGULATORY OPTIONS FOR SOLAR FEED-IN PRICING

The terms of reference asks us to consider the mechanism by which a fair price could be implemented in Queensland (mandatory or other). This chapter outlines regulatory options for ensuring fair solar export pricing and sets out a proposed regulatory framework for regional Queensland.

Key points

- There are several regulatory measures that could be considered for the solar export market. Price-related regulatory options range from the regulator observing and reporting on pricing behaviour to more direct measures, where the regulator has the power to approve or recommend prices.
- In SEQ, the benefits of regulation would not outweigh its costs. The government should consider including solar feed-in pricing in the electricity market monitoring arrangements.
- For regional Queensland, a price approval regime is likely to achieve the government's objectives at least-cost. A price approval regime for solar exports will afford the same level of customer protection as price setting, while opening opportunities for different offers and products for regional solar PV owners.
- Under a price approval regime, regional retailers would be obliged to:
  - purchase solar exports from small customers in regional Queensland; and
  - submit their offers to the regulator for approval on an annual basis.
- The regulator should approve the offers, unless they are materially inconsistent with efficient pricing. If the regulator does not approve the offers, it can request retailers submit revised offers for approval.
- Retailers may still choose to offer a single feed-in tariff, but they may also offer other products, services or discounts, including solar power purchase agreements, and locational and time-of-export pricing.
- The price approval regime should be reviewed if:
  - the regulator identifies a sustained market power problem despite the price approval regime in place;
  - the regulator identifies that the potential for exercise of market power no longer exists; or
  - market conditions change materially (for example, through competition or technological change).

9.1 Regulatory options

Where regulation is proposed, the Queensland Government's RIS system guidelines (Box 25) require that regulatory proposals are developed in accordance with best practice processes — including establishing a case for action before considering a regulatory response and evaluating a range of feasible options to identify which option will deliver the greatest net benefit to the community.

Box 25: Queensland Government Regulatory Impact Statement System Guidelines

The Queensland Government has committed to ensuring that all regulatory processes are consistent with the following principles:

- establishing a case for action before addressing a problem;
- considering a range of feasible policy options including self-regulatory, co-regulatory and non-regulatory approaches, and an assessment of their benefits and costs;
- adopting the option that generates the greatest net benefit to the community;
- ensuring, in accordance with the Competition Principles Agreement, that legislation should not restrict competition unless it can be demonstrated that:
  - the benefits of the restrictions to the community as a whole outweigh the costs; and
  - the objectives of the regulation can only be achieved by restricting competition.
- providing effective guidance to relevant regulators and regulated parties in order to ensure that the policy intent and expected compliance requirements of the regulation are clear;
- ensuring that regulation remains relevant and effective over time;
- consulting effectively with affected key stakeholders at all stages of the regulatory cycle; and
- ensuring that government action is effective and proportional to the issue being addressed.

Source: Queensland Government 2013.

Regulatory measures that can address market power and pricing issues range from providing pricing information, through to more active measures where the regulator has the power to approve or recommend prices (Figure 59).

Figure 59: Forms of regulation

Some regulatory forms are more effective than others depending on the nature of the problem. For example, direct price regulation may provide overall benefits where there is monopoly power, whereas price monitoring or more light-handed approaches may be sufficient where market dominance is less of a concern. Determining the right regulatory approach requires an assessment of the benefits of regulation (such as limiting monopoly pricing and consumer protection), against the costs (such as setting regulatory prices too high or too low, compliance costs on firms and regulators and reduced firm innovation).

9.1.1 Price information

Providing consumers with transparent price information can help consumer decision-making and provide some discipline on firm behaviour. An example of this type of regulation is the requirement for retailers to submit pricing information to the energy price comparator website.

Some regulators, such as IPART, also publish benchmark solar feed-in tariffs to inform consumers. The benchmark range provides guidance on the likely value of the electricity exported by PV customers. It aims to assist customers in deciding whether to install a PV unit and compare market offers. IPART estimates the benchmark range using the wholesale market value method.

The government or regulator may require the retail entity to disclose the cost drivers and methodology used to determine prices to improve transparency and consumer understanding. Price information may also be subject to informal 'surveillance' by the regulator to ensure that prices paid do not reflect excessive exercise of market power.

The advantage of price information is that it is likely to impose low implementation and recurrent costs on firms and the regulator compared to more direct forms of regulation. However, pricing information alone is unlikely to be sufficient in the presence of significant market power. In addition, information may not be particularly useful — especially if the minimum information requirements imposed or quality of information are low.[222]

Price information is likely to be of most benefit when pricing information is difficult to obtain or interpret:

- in a market with competing suppliers, where consumers can compare different product offerings and prices and choose a supplier; or
- in a monopoly environment where costs and prices can be verified or there is a sufficient level of consistent behaviour between the regulated entity and its customers.

9.1.2 Price monitoring

Under price monitoring regulation, the regulator monitors and reports on prices and market activity. A regulated entity may be required to provide information to the regulator, which stakeholders are then able to review and report on. Price monitoring has been used in the regulation of ports and airports in Australia, as well as the retail water sector in SEQ.

The Productivity Commission[223] noted that various price monitoring approaches are available to the regulator, including information collection and reporting, benchmarking, and the monitoring of key performance indicators.

Price monitoring can establish whether market power is likely to be a concern and can allow a regulator to 'track' prices over time. It is likely to be less intrusive than other regulatory forms, which can reduce compliance costs for firms and allow greater flexibility.[224] The Queensland Government noted that price monitoring has the ability to:

- restrict excessive prices;
- provide remedial action if required; and
- be useful in addressing any new issues that may emerge.[225]

However, the cost of pricing monitoring is likely to be dependent on the information reporting requirements imposed on the entity by the government/regulator.[226] For example, Queensland Urban Utilities (QUU), with reference to the previous SEQ retail water price monitoring framework, considered that:

[222] QCA 2014, p. 19.
[223] PC 2004, p. 337.
[224] QCA 2014, p. 19.
[225] The Queensland Government, cited in the Australian Law Reform Commission (ALRC) 2004, p. 586.
[226] For example, the original QCA price monitoring of SEQ retail water providers involved retailers having to provide high-level information on a small number of indicators. However, as noted by QUU 2013, p. 3 in subsequent years a more comprehensive price monitoring framework was developed with a view to transitioning to deterministic regulation.

> *A framework which was light handed in name ("price monitoring") was actually heavy handed in its application. Given that these reviews occurred on an annual basis, it meant that it was more heavy handed than the price deterministic regimes seen in other Australian jurisdictions.*[227]

The Productivity Commission also noted that:

> *whilst an effectively designed monitoring regime can offer significant improvements in economic efficiency, if these elements are not managed properly, monitoring has the potential to be ineffective at regulating behaviour at one extreme, and almost as intrusive as the current system at the other.*[228]

A disadvantage of price monitoring is that an assessment of whether prices reflect an exercise of market power will not usually be known until after the price is set, as the regulator undertakes an ex post assessment. It is therefore difficult for any regulatory action to be taken, if required, until the next regulatory review. Regulatory uncertainty may also be created if there is a lack of clarity about behaviour that may trigger more intrusive regulation.[229]

Price monitoring may be appropriate where, in the absence of countervailing market power:

- stakeholders are able to understand the information provided (either of their own volition or with the assistance of a regulator's analysis); or
- some prospect of more detailed direct regulation is in place.[230]

9.1.3 Price approval

Price approval is a direct form of regulation, characterised by a regulated entity submitting prices to the regulator for its approval. This type of regulation (as well as price setting) may be required where there are monopoly pricing practices.

Price approval has the advantage, compared to full price setting, of potentially being less intrusive and costly while achieving similar outcomes — that is, the regulator still has oversight of pricing and can determine that the price being offered is consistent with efficient pricing. A price approval process for solar feed-in tariffs operates in Western Australia, albeit prices are approved by the Western Australian Government, rather than an independent regulator.

Price approval may not be appropriate or cost-effective where firms have significant market power (and strong incentives to exercise that market power) or where the complexity of markets and information asymmetries mean that it would be difficult for a regulator to make a sufficiently informed assessment for approval. However, these conditions do not appear to exist in the solar export market in Queensland. A wide range of pricing information is available from retail market offers, wholesale market outcomes and the bank of regulatory knowledge from regional feed-in tariff decisions and electricity tariffs in Queensland and interstate.

As a 'lighter' form of regulation (compared to price setting), price approval may give the regulated entity the flexibility of using alternative methods to satisfy a desired regulatory outcome.[231] This is likely to better promote efficiency, innovation and improved outcomes for consumers.

[227] Queensland Urban Utilities (QUU) 2014, p. 14.
[228] PC 2004, p. 337.
[229] PC 2004, p. 337.
[230] QCA 2014, p. 20.
[231] PC 2004, p. 338.

9.1.4 Price setting

Price setting involves a regulator directly determining prices, similar to the current situation where the QCA, under the *Electricity Act 1994*, is directed by the Minister to set a single regional feed-in tariff annually.

Traditionally, price setting is the most costly and intrusive form of regulation. The Productivity Commission has noted that under 'intrusive cost based regulation' there can be high costs, time delays, constraints on innovation and a higher potential for regulatory error.[232] However, the current price setting arrangements for regional Queensland do not appear to have high compliance costs — the QCA is able to set the feed-in tariff based on published data and information acquired for regional electricity price setting.

The regulator setting a feed-in tariff is the most direct way to limit exercise of market power. However, it also has the highest risk of regulatory error — that is, setting the feed-in tariff too high or too low:

> *The critical importance of prices to decision making by producers and consumers, together with the informational and other constraints on regulators, mean that price oversight must always face the real risk of distorting investment and reducing incentives to be efficient and innovative, as well as placing a compliance burden on the firms subject to regulatory oversight. In other words, against the possible consequences of market failure need to be set the possible consequences of government regulatory failure.*[233]

A price setting regime may reduce flexibility and innovation, as the regulated business is required to operate within a more rigid regulatory framework.

9.2 Regulatory options in the SEQ market

The analysis in Chapter 4 found that the level of competition in SEQ was effective in providing choice and price benefits to consumers, and that competitive pressures are likely to continue to increase. As a result, the competition assessment concluded that there is not a case to regulate feed-in tariffs in SEQ to address market power. Chapters 5 and 6 did not find other reasons to regulate feed-in tariffs.

Notwithstanding this, some stakeholders questioned whether, due to concerns of solar PV owners, there was a role for some form of 'precautionary' regulation to provide consumers with a level of comfort that solar export pricing was fair. Three options were identified:

- a mandatory minimum feed-in tariff, where the QCA would, in essence, set a floor price for solar exports;
- a nonbinding benchmark tariff, where the QCA would publish a benchmark tariff for solar exports in SEQ; and
- price monitoring, where the QCA would monitor and report on solar feed-in tariffs as part of broader retail electricity market monitoring.

9.2.1 A minimum feed-in tariff

Price floors are generally set to protect producers of certain goods and services (in the case of minimum feed-in tariffs, solar PV exporters). Historically, price floors were mostly used in agricultural markets that governments viewed as important — more contemporarily, the minimum

[232] PC 2004, pp. 331–332.
[233] Banks 2000, p. 9.

wage is the most prominent example of a price floor. Price floors (or ceilings) also are sometimes introduced in markets transitioning to competition, where there is a high level of uncertainty as to market outcomes.

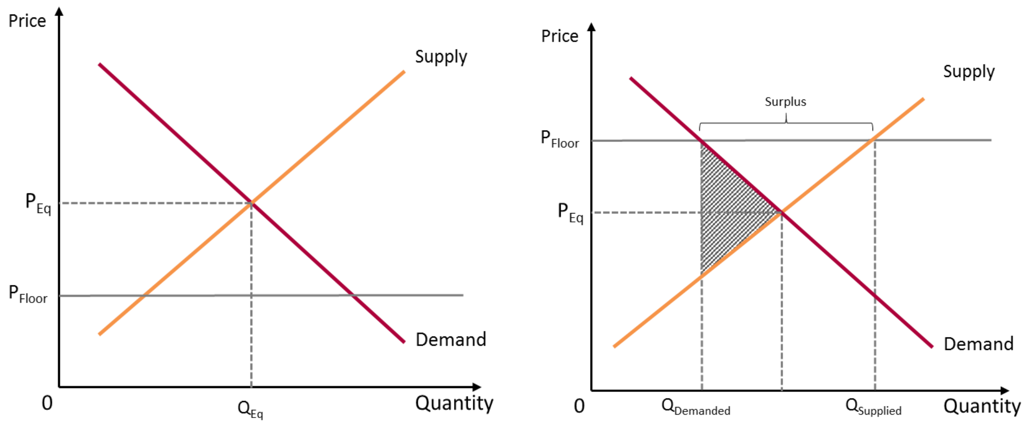
Unlike the case for regulating a monopoly, where price regulation can increase economic efficiency, price regulation in a competitive market will redistribute income between producers and consumers and generally harm economic efficiency.

Box 26 provides a stylised illustration of the impact of a price floor.

Box 26: Impact of a floor price

If a government introduces a floor price then two outcomes are possible:

- the price floor is nonbinding if set below the market equilibrium price;
- the price floor is binding if set above the equilibrium price, and will lead to a surplus.



With a binding floor price, consumers pay a higher price to producers. The result is that the quantity supplied is greater than the quantity demanded creating a surplus. The gains from trade that are lost due to the floor price represents the 'deadweight loss' (shaded area).

A floor price is also often associated with an increase in government spending to absorb the surplus (as was the case with many agricultural floor price schemes (see Chapter 3)) and less efficient and innovative producers.

In the context of the SEQ market, there is a spread of offers available — with some retailers not offering a feed-in tariff and others offering 11c/kWh. If a minimum price was set based on some variation of the avoided cost method, which is driven by the wholesale price of electricity, then many retailers already offer feed-in tariffs well above such a minimum price. There is a small number of retailers that do not, but as solar PV owners can already access offers from the retailers that do, consumers would be no better off from a minimum feed-in tariff.

However, the introduction of a minimum feed-in tariff may result in a number of unintended consequences. First, there is a risk that the pricing information provided by a minimum price may actually directly harm the solar PV owners it is intending to assist. As a floor price would most likely be set below market clearing levels, solar PV owners should be able to source higher offers. But to the extent that some consumers may assume that a minimum floor price set by a reputable regulator should be considered a reasonable 'deal', they may not search for a better offer. Similarly, by comparing tariff offers to the minimum, consumers may believe they are receiving a high feed-in tariff when it could still be below competitive levels.

Second, a minimum floor price may act as a focal point for retail pricing, and the result may be that consumers receive the minimum, but no more. For example, there is evidence of a collusive focal-point effect of price ceilings in various markets:

> *Knittel and Stango (2003) investigate the interest rates of U.S. credit cards in the 1980s where various price ceilings were effective and report that 'tacit collusion at nonbinding state-level ceilings was prevalent during the early 1980's'. Eriksson (2004, p.1), analyzing the 1999 deregulation of the market for dental services in Sweden, states that the 'Swedish government was worried that the ceiling was serving as a focal point for implicit price collusion' and that 'a removal of the price ceiling could lead to increased competition and lower prices'. DeYoung and Phillips (2006, p.1) document that 'over time, payday loan prices in Colorado have gravitated toward the legislated price ceiling'. Finally, Ma (2007) studies price ceilings in Taiwan's flour market, and finds evidence that firms in this market set prices 'above competitive equilibrium levels during most of the regulation period' and that '[o]bservations on prices also show that all flour firms set their prices equal to ceilings, without exception.*[234]

However, replicating a focal-point effect of price ceilings in experimental markets has produced less sanguine results:

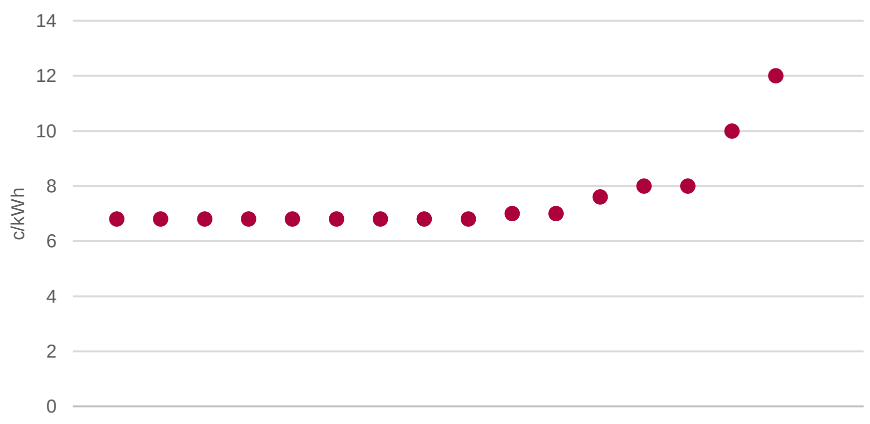
> *our results again fail to support the focal-point hypothesis. Collusion is as unlikely in markets with a price ceiling as in markets with unconstrained pricing.*[235]

Nevertheless, there is sufficient evidence to exercise some caution:

> *If, then, there are obvious focal points in a market, there is clear risk that, by inducing similarity among market participants in their starting points for assessment, the effect of price regulation is to achieve a co-ordination of behaviour that would be impossible 'but for' the policy-induced focal points.*[236]

As highlighted above, it is challenging to isolate any impact of a minimum feed-in tariff on pricing outcomes. However, jurisdictions with minimum feed-tariffs are more likely to have pricing outcomes at the minimum, with less range. For example, in South Australia more than half of the available offers provide the regulated minimum feed-in tariff (Figure 60). In Victoria, there is some clustering around the minimum feed-in tariff, but a more even distribution of offers.

Figure 60: South Australian feed-in tariff offers



Note: The minimum feed-in tariff is 6.8c/kWh for 2016.

Source: EnergyMadeEasy website, https://www.energymadeeasy.gov.au.

[234] Engelmann & Muller 2011, p. 2.
[235] Engelmann & Muller 2011, p. 1.
[236] Yarrow 2008, p. 25.

Third, a minimum feed-in tariff for solar exports may reduce the range and quality of solar products and services offered to the market. As discussed in Chapters 2 and 4, many retailers are offering new solar products and services, not necessarily based on feed-in tariffs:

> *It is also important to consider how regulation of feed-in-tariffs might restrict product development; regulated pricing introduces risk for retailers because they cannot control the minimum price for exporting solar. Accordingly, the introduction of a regulated mandated minimum feed-in-tariff would only serve to limit product innovation and development at a time where solar energy markets are undergoing significant change with new products and technologies entering the market.*[237]

> *The level of the feed-in-tariff … is only one element for customers to consider when choosing a retailer. Some customers may place a high store of value on the level of a feed-in-tariff, while others with embedded generation may emphasise a preference for other features of energy products (such as a discount or fixed pricing for their energy supply). As such, customer valuation of the level of a feed-in-tariff will vary according to these preferences. Regulating a minimum feed-in-tariff constrains the ability of retailers to innovate and may create a sub-optimal price ceiling for some customers seeking to export electricity to the grid.* [238]

Finally, the most significant consideration is the risk and subsequent costs of setting a minimum price incorrectly. In reviewing the case for such precautionary price regulation in electricity markets, Professor George Yarrow noted:

> *In theory the desired effect of such price regulation is that it will not constrain or otherwise impede competitive conduct, but that it will constrain the exploitation of (residual) market power. In practice, achieving this degree of precision in the targeting of public policy intervention is an impossible task, and, as a practical matter, it is important to recognise that impossibility.*[239]

Yarrow identified the underlying problem as the difficulty in specifying a price control that can distinguish between market prices that are due to normal competitive factors, and the exploitation of market power:

> *In order to be able to do this, what in effect is required is a form of price regulation that indexes the controlled price to the competitive price. However, that is a far, far more difficult exercise than regulating prices in a way that links them with costs, in the manner of traditional monopoly regulation. And it can safely be said that regulators, no matter how wise and no matter how well resourced, could be expected to make significant mistakes – because the problem has to do with information. The determination of a competitive price is a process that (implicitly) makes use of huge amounts of information, of such scale and scope as cannot feasibly be processed by a single decision making unit such as a regulatory agency.*[240]

If a minimum feed-in tariff is set above market clearing levels, then the community will pay a higher price for solar exports than is optimal, potentially resulting in a range of adverse outcomes for solar customers, non-solar customers and market participants. As noted by IPART:

> *[I]t would be difficult for us to recommend an exact mandatory rate because of the individual characteristics of retailers and their PV customers. Setting the feed-in tariff too high could affect the attractiveness of PV customers in the market and potentially affect the financial viability of retailers.*[241]

> *Fixing minimum feed-in-tariffs at a certain level will provide retailers with less incentive to innovate to reduce the costs associated with solar PV customers and offer competitive prices.*[242]

[237] Origin, sub. DR15, p. 3.
[238] Origin Energy, sub. 24, p. 4.
[239] Yarrow 2008, p. 21.
[240] Yarrow 2008, p. 21.
[241] IPART 2012b, p. 6.
[242] IPART 2015.

The ERAA noted the potential costs of a minimum regulated tariff in a deregulated electricity market:

> *In anticipation of the deregulation of retail energy prices in Queensland from 1 July 2016, the ERAA does not support a mandated R-FiT as it introduces an asymmetric risk into retail energy markets. Should a minimum R-FiT be set too low (or not be set at all), retailers will compete to offer customers R-FiTs that best suit their needs. Should a minimum R-FiT be set too high, retailers will be forced to purchase exported energy at higher rates than could be purchased elsewhere. This outcome would not be consistent with the long term interests of Queensland consumers, particularly solar consumers who may experience a reduction in competition and associated benefits.*[243]
>
> *Government intervention in the retail electricity market to mandate a minimum-feed-in-tariff may also stifle competition by acting as a barrier to entry for new retailers; this in turn may restrict the overall availability and quality of products offered. For instance, a small retailer may wish to enter a market and compete for customers without solar PV by offering attractive prices for their general tariffs to non-solar customers. The introduction of a mandated minimum feed-in-tariff will act as a disincentive to such new entrants and may decrease the value proposition of their non-solar products by increasing the cost of the feed-in-tariff.*[244]

In a deregulated electricity market with a regulated minimum feed-in tariff, retailers may:

- to the extent possible:
  - adjust other elements of their offer (for example, electricity tariffs) to absorb the cost of the feed-in tariff; or
  - adopt non-pricing strategies to avoid serving solar customers;
- choose not to service the SEQ market.

Among the retailers that do not currently offer a solar feed-in tariff product or would choose to offer a tariff below the minimum price, many compete on electricity price discounts without additional products and services. As discussed in Chapter 4, in some cases solar PV owners may be better off with a low feed-in tariff (or no feed-in tariff), but a lower electricity tariff.

If smaller retailers choose not to enter (or exit) the SEQ market, the competitive pressure will be reduced both on solar feed-in tariffs and electricity prices.

9.2.2 A nonbinding benchmark feed-in tariff

In New South Wales, IPART publishes a benchmark range for fair and reasonable solar feed-in tariffs (in 2015–16 this range is 4.7 to 6.1c/kWh). In reviewing the options for feed-in tariff regulation in 2012, IPART stated that benchmarking pricing information would:

- inform PV customers of the potential fair and reasonable value of their electricity exports in the coming financial year
- better enable PV customers to assess retailers' feed-in tariff offers
- encourage retailers to voluntarily offer competitive feed-in tariffs that reflect the fair and reasonable value of the electricity exported by PV customers.

A nonbinding benchmark feed-in tariff would provide solar PV owners with a source of pricing information and may impose some discipline on retailers to offer competitive feed-in tariffs. A

[243] ERAA, sub. 31, p. 2.
[244] Origin Energy, sub. 24, p. 4; ESAA, sub. 37, p. 4.

nonbinding benchmark will not carry the risk that direct pricing regulation has of getting prices wrong.

Even so, a benchmark tariff is not costless. First, there are the direct costs (albeit comparatively low) incurred by the regulator and market participants in setting a benchmark tariff. It is not clear whether a benchmark tariff would provide substantial new information given existing sources from the wholesale market, comparator websites and past regulatory decisions.

Second, as with a minimum price, there is a risk that a benchmark price can act as a focal point for pricing coordination amongst retailers to the detriment of consumers. The 2013 QCA review of feed-in tariffs cautioned against benchmark tariffs:

> *[P]ublishing a benchmark indicative range could dilute the benefits of competition by not providing an incentive for retailers to avoid revealing their efficient costs. It is likely that the lower bounds of a benchmark range, if published by the Authority, would effectively be viewed by retailers as a minimum obligation and would offer voluntary tariffs no higher than that level, regardless of their individual financial capacity to make more generous offers. There appears to be some evidence of this in NSW, where a number of retailers adjusted their voluntary feed-in tariff offers to reflect the lower bound of the IPART's 2012-13 benchmark range after it was published.*[245]

Determining if a benchmark price has an impact is difficult. In New South Wales, for those retailers that offer a feed-in tariff, more than 60 per cent of offers are set in the benchmark range.[246] But, isolating any impact of benchmark pricing on retailer behaviour would need to control for the range of other factors that influence pricing decisions. For instance, the existence of price convergence is not necessarily evidence of a benchmark price driving retailer pricing — feed-in tariffs may be expected to oscillate around the cost of wholesale electricity, since that is the cost retailers would incur if they did not purchase solar exports. What is clear however, is that benchmark pricing has not resulted in higher feed-in tariffs compared to the unregulated Queensland market, with feed-in tariffs ranging from 5–10c/kWh and a median price of 5c/kWh.

9.2.3 Price monitoring

As highlighted above, price monitoring involves a regulator monitoring and reporting on prices and market activity. A range of market monitoring for the Queensland electricity market is already in place:

- an annual AEMC report on the state of retail competition across the NEM, which assesses each jurisdiction against a range of competitive market indicators;
- an annual AER retail market performance report covering a range of non-pricing indicators such as customer service, hardship and disconnection; and
- Energy Ombudsman reports, AEMO data, and departmental complaint and customer service information.

Additional monitoring following deregulation is proposed, including an annual market comparison report by the QCA focusing primarily on price and cost movements in SEQ.

Several submissions considered that price monitoring was the best option for SEQ:

> *AGL considers that price monitoring conducted using publicly available information strikes the right balance between imposing regulatory costs and ensuring that solar customers are receiving a fair price for their solar exports.*[247]

[245] QCA 2013a, p. 93.
[246] EnergyMadeEasy website, https://www.energymadeeasy.gov.au, accessed 11 April 2016.
[247] AGL, sub. DR14, p. 1.

> *[I]t makes sense for the Government to review the solar PV market as part of any market monitoring that may take place under a deregulated retail market. This will allow the Government to examine a range of factors that are appropriate for both the retail electricity market and the feed-in-tariff market. Origin considers that these arrangements sufficiently empower the Government to make an informed judgment regarding the effectiveness of competition in the feed-in-tariff market. The most suitable agency to undertake a review should operate at arm's length to provide independent advice to Government.*[248]

However, there were some exceptions to that view:

> *In the drive to deregulate the Solar PV export market, more will be needed to actively ensure the protection of customer interests. It is questionable whether an annual "market monitoring" process as articulated by the draft report will be regarded by customers as sufficient.*[249]

The Queensland Government could consider including solar feed-in pricing in the QCA's market monitoring role. That would add a small amount to the administrative cost of monitoring but may improve information for:

- customer understanding and decision-making by reducing information search costs and providing independent assessment of the market; and
- the government to assess price-related indicators of effective competition and emerging trends in the solar export pricing market.

9.3 Summary

Any assessment of regulatory options for SEQ must be considered within the context that evidence of a significant problem that would warrant regulatory intervention has not been established:

> *[G]overnments do not need a solar export pricing policy where effective competition exists in their retail electricity market for feed-in-tariffs. Price regulation is not as effective at determining efficient and fair prices as an effectively competitive market. There is no compelling reason to set policy parameters for the regulation of the value of solar energy where the market is working to offer customers a range of feed-in-tariffs, as is demonstrably the case in south east Queensland.*[250]

> *CCIQ does not believe there is evidence of market failure in the South East Queensland (SEQ) retail market. Many small businesses in SEQ have successfully negotiated feed-in prices with their retailers at competitive rates… CCIQ recommends feed-in tariff prices be left to the customer and the retailer to negotiate in SEQ.*[251]

> *A strong rationale is required to regulate one segment of a market (solar feed-in tariffs) when there is no price regulation for the supply of electricity which is arguably a far more essential service – particularly as a market failure has not been demonstrated.*[252]

Within this context, and assessed against the efficiency, equity and policy governance principles outlined in Chapter 3, there does not appear to be a strong case for precautionary regulation of feed-in tariffs in SEQ. In particular, while a minimum feed-in tariff is unlikely to provide benefits, it has scope for costs. The adverse consequences of a minimum feed-in tariff could be significant in both the solar export and electricity market, particularly if a minimum feed-in tariff impedes or deters participation in the retail electricity market.

The case for either a nonbinding benchmark price or market monitoring is more finely balanced. Both options are likely to be relatively low-cost, assuming they are implemented efficiently. But,

[248] Origin, sub. DR15, p. 7.
[249] Don Willis, sub. DR6, p. 8.
[250] Origin, sub. DR15, p. 2.
[251] CCIQ, sub. 21, pp. 6–7.
[252] AGL, sub. DR14, p. 2

they are also likely to have corresponding low benefits, given the range of pricing information already available in the market. Some stakeholders noted, however, the value of precautionary monitoring and market information may be greater than its direct benefits, if it avoids ill-conceived regulatory intervention.[253]

A nonbinding benchmark tariff does have some downside risks which may be more pronounced in a market with changing products and offers. These risks do not appear to be offset by benefits to consumers.

Including solar feed-in tariffs in the electricity price monitoring arrangements for SEQ would appear to best meet the relevant principles, assuming the monitoring role does not materially add to compliance costs. It would also ensure consistent arrangements for electricity and solar export pricing. The Queensland Government may wish to explore this option, which would provide both an ongoing assessment of the market and greater assurance to consumers.

9.4 Form of regulation in regional Queensland

Chapter 4 concludes that, on balance, there is a sound case for some form of mandatory solar export pricing in regional Queensland.

The findings in that chapter indicate that despite some disciplines on regional retailers, they retain market power for solar export pricing, particularly once regional consumers have purchased solar PV.

Even so, unlike electricity prices more broadly, the exercise of market power for solar export pricing is unlikely to have significant adverse impacts on the community as a whole, even if it results in some transfers.

The form of regulation should limit the likelihood that retailers will exercise excessive market power, while minimising the scope for regulatory error and compliance burdens. The Competition Policy Review highlighted the need to ensure regulatory settings do not impede evolving technology and innovation, particularly in rapidly changing markets:

> *We also need flexible regulatory arrangements that can adapt to changing market participants, including those beyond our borders, and to new goods and services that emerge with rapidly evolving technology and innovation. Market regulation should be as 'light touch' as possible, recognising that the costs of regulatory burdens and constraints must be offset against the expected benefits to consumers.*[254]

For solar export pricing, price setting and price approval are likely to result in similar compliance costs, and will provide sufficient transparency and protection to consumers. However, regulatory error and the potential to impede solar PV market development are higher under a price setting approach.

We consider that a price approval regime would best address the potential for 'post-purchase' buyer power from retailers, while recognising the limits and impacts of that market power and scope for regulatory error. Regulation through price approval provides the greatest opportunities for efficiencies and improvements in the products and services offered to customers in regional Queensland.

[253] Origin, sub. DR15, p. 8.
[254] The Australian Government Competition Policy Review 2015, p. 24.

Under the proposed price approval regime retailers would continue to be obliged to 'purchase' solar exports from small customers. But, rather than a single tariff being set annually by the QCA, retailers would be required to submit solar offers to the QCA for approval.

9.4.1 Who would be covered by regulation?

Retailers covered by the existing feed-in tariff regulation, Ergon Energy (Retail) and Origin Energy (for customers connected to the Essential Energy supply network), would be subject to the price approval regime.

Under the existing arrangements, to be eligible for the regulated feed-in tariff customers must:

- operate a solar PV system with a maximum inverter capacity not exceeding 5 kW;
- consume less than 100 MWh of electricity a year (the average home uses approximately 4053 kWh a year);
- for the premises where the solar PV system is installed, be a retail customer of:
  - Ergon Energy Queensland; or
  - Origin Energy (only if they are connected to the Essential Energy supply network);
- have a network connection agreement in place with an electricity distributor signalling its approval to connect the PV system to the electricity grid; and
- have only one solar PV system receiving the feed-in tariff per premise.

CCIQ and APA Group indicated that eligibility should be extended to larger small business customers and other technologies:

> *[M]any small businesses use over this threshold and therefore fall outside the remit of protections available against abuse of market power. CCIQ believes that eligibility should seek to take into account high energy using small businesses.*[255]
>
> *[T]he current policy design for the solar PV FiT in Queensland provides solar with an unfavourable advantage over other low emissions fuels such as natural gas. APA believes however, that by including low emissions fuels in an amended scheme, fairness and equity could be restored.* [256]

The eligibility criteria are presumably designed to capture most residential customers. However, they are somewhat arbitrary:

- Small customers are defined based on *consumption*;
- Eligibility is confined to solar PV; and
- The 5 kW limit may distort efficient investment away from more cost-effective larger systems.

Even so, the eligibility criteria are consistent with the rationale for regulation — to protect small consumers from abuse of market power. And, in relation to renewables technologies, distortionary impacts will be limited until cost-effective alternatives to solar PV become realisable options.

We have not proposed to modify eligibility, as the terms of reference asks us to determine arrangements for small solar PV customers only. Going forward, the government should ensure that eligibility criteria are non-distortionary.

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[255] CCIQ, sub. DR18, p. 2.
[256] APA Group, sub. DR4, p. 2.

9.4.2 QCA approval of solar export offers

Under the proposed price approval process, retailers serving small customers in regional Queensland would be required to submit their solar export offer(s) to the QCA for approval. The QCA must approve the offers unless they are materially inconsistent with the following pricing principles (drawn from the principles established in Chapter 3):

- *Efficiency*: Are the pricing offers consistent with achieving economic efficiency? Efficiency is defined to ensure resources are allocated to their highest valued use, output is produced at minimum cost and new processes, systems and services are introduced in a timely way.
- *Effectiveness*: Are offers transparent? Are they as simple as possible or appropriately balance efficiency versus simplicity where there is a trade-off?
- *Equity*: Do the offers avoid some consumers subsidising other consumers? (that is, are they fair?)

In the event a retailer's offer is not approved, the QCA can request the retailer to resubmit a revised offer for approval.

Implementing a price approval process will require amendments to the *Electricity Act 1994* to modify the existing requirement for the QCA to set a single regional price, and to set out the price approval process.

During consultation, it was noted that depending on the structure of regulatory guidance, the price approval process could risk morphing into an extended version of the current price setting arrangements. For example, if the QCA undertook a process to determine efficient prices or a price setting process akin to what occurs under the current arrangements to assess proposed offers.

The process should operate on the basis that the regulator must approve the offer/s unless they are materially inconsistent with the pricing principles (primarily, the offers should be approved unless the regulator can establish that the retailer is using market power to set solar PV offers substantially lower than what could prevail in a competitive market). The QCA should neither be required to determine efficient prices, nor determine the type or design of offers. Thus, the key objective is to restrain excise of retailer market power, not set or design pricing. The assessment should draw on existing sources of information.

Given the QCA’s role in determining regulated electricity tariffs in regional Queensland and pricing regulation more generally, it is well-placed to determine whether a retailer's solar export offers are consistent with the pricing principles.

9.4.3 Offers under a price approval regime

The use of a price approval regime, rather than price setting, will give retailers the flexibility to offer consumers different types of solar products and more complex feed-in tariff structures, such as solar power purchase agreements, discounts, time of export pricing and location-based pricing.

Ergon Energy (Retail) noted there could be a range of possible approaches to solar export pricing:

> *Some of these options could include consideration of the following:*
>
> - *Declining block export tariff – define different volume export blocks and corresponding declining export rates;*
> - *Time of export feed-in tariff – this could incentivise customers to install solar on the western side of their roof by developing a feed-in tariff which has a higher price based on the time of day. This would allow better alignment with higher demand periods in the NEM which often occur in the early evening; or*

- *Combined battery and solar feed-in tariff – this could incentivise customers to purchase batteries for storing their existing excess solar, or incentivise new customers to purchase combined solar and battery products.*[257]

However, stakeholders argued that the range of services and products offered are currently constrained by metering and settlement, billing systems, and some regulation and policies:

> *It may be appropriate to consider more complex feed-in tariff structures incorporating location and time only after cost reflective network and retail tariffs have been established in a similar manner in the first instance, or when consumer-facing technology can simplify this complexity for consumers.*[258]

A single feed-in tariff may therefore still be the most cost-effective way to purchase solar exports and may continue under a price approval regime. Nevertheless, retailers have the opportunity to explore alternative options.

Locational pricing

The scale and variability of costs across the Ergon Energy distribution area mean that the value of solar PV exports to a retailer is likely to vary depending on the location of the PV generation. As a result, there are potential gains for both consumers and retailers from locational pricing.

The transmission of electricity results in some of the energy being lost in transit. Given the very large geographic area of Ergon Energy's network, and the locations of large-scale generators, network losses can be expected to show significant variation across regions.

Locational feed-in tariffs would take into account reduced network losses from solar PV generation. Solar PV exporters would be paid a feed-in tariff to recognise the benefit of having to transport energy shorter distances, resulting in less energy losses. Location-based solar export pricing operates in Western Australia (Box 27).

[257] Ergon Energy Queensland, sub. 35, p. 6; Master Electricians Australia, sub. 15, p. 1 also proposed a solar/battery tariff.
[258] AGL, sub. 19, p. 4.

Box 27: Location-based solar export pricing in Western Australia

Horizon Power, which services regional Western Australia, has location-based solar export pricing. Buyback rates are established using the avoided cost of generation in each town and are approved by government. Feed-in tariffs in grid-connected areas are similar to those in the South West Interconnected System (SWIS). Areas where generation costs are high — for example, generation in isolated regions using diesel generation — receive higher feed-in tariffs. Horizon Power offers the buyback price to all residential customers if they live in a town that can accept additional renewable energy systems.

The 1 July 2015 buyback rates are shown below.

Town	*Buyback offer* (c/kWh)*	*Town*	*Buyback offer* (c/kWh)*
Ardyaloon	42.71	Kalumburu	50.55
Beagle Bay	44.64	Kununurra	10.33
Bidyadanga	34.11	Laverton	32.82
Broome	7.14	Leonora	14.18
Camballin/Looma	29.11	Marble Bar	48.05
Carnarvon	10.56	Meekatharra	26.42
Coral Bay	19.75	Menzies	51.41
Cue	26.75	Mount Magnet	21.20
Denham	27.93	Norseman	26.33
Derby	7.14	Nullagine	41.86
Djarindjin	46.30	NWIS**	7.68
Esperance	10.29	Onslow	18.79
Exmouth	7.14	Sandstone	27.64
Fitzroy Crossing	7.19	Warmun	39.76
Gascoyne Junction	46.59	Wiluna	28.41
Halls Creek	7.65	Yalgoo	28.76
Hopetoun	34.30	Yungngora	39.47

** Prices rounded to two decimal places. Exclusive of GST. ** Includes Port Hedland, Roebourne and Karratha.*

In its 2013 review of solar feed-in tariffs in Queensland, the QCA recommended the use of location-based feed-in tariffs for regional customers. It recommended feed-in tariffs be developed based on the existing Ergon Energy transmission and distribution pricing zones and loss factors, as used to determine the allocation of its network charges. It also noted location-based feed-in tariffs should not be excessively complex or costly to administer.[259]

Ergon Energy has three pricing zones — the east zone, Mount Isa zone and the west zone (see Chapter 4). Box 28 outlines how pricing zones are determined.

[259] QCA 2013a, p. 52.

Box 28: Ergon Energy Queensland's zones for retail pricing

The determination of Ergon Energy's zones is based on:

- a comparison of the distances the customers are from a transmission network connection point (TNCP) — the further they are from the connection point the more distribution assets are required;
- minimising cross-subsidisation between the higher cost, less populated western networks, and the lower cost, more heavily populated eastern networks – the further the distance and lower the population density, the more expensive the assets and higher the cost to supply;
- identifying those geographic areas which have a similar cost to supply — remote areas of western and far northern Queensland compared with the higher-density eastern areas;
- simplicity for customers and retailers to understand; and
- identifying a logical 'break point' in the electrical supply network — open points in the distribution system that separate different areas of supply.

The QCA split Ergon's east and west zones into three 'transmission use of system' (TUOS) regions and calculated average transmission loss factors combining:

- *marginal loss factors*: transmission losses are reflected in marginal loss factors measured at each transmission connection point (TCP) on the Powerlink transmission network. The marginal loss factors indicate the average losses incurred when transporting electricity from the regional reference node to each TCP; and
- *distribution losses*: within each network pricing zone, distribution losses also occur. Distribution losses are primarily a function of distance between the load and the point where the distribution network joins the TCP.

A larger average combined loss factor means that more energy is lost in transport relative to another area. For the calculation of a feed-in tariff, a larger loss factor means a higher feed-in tariff recognising the benefit of solar PV generation in reducing energy losses. Loss factors are lowest in SEQ (1.072), and highest in the west zone, where population density is lowest (Table 32).

Table 32: Average combined loss factors by regional zone

Zone	*Combined loss factor*	*TUOS1*	*TUOS2*	*TUOS3*
Energex—NSLP	1.072			
Ergon Energy – east		1.0934	1.1866	1.2268
Ergon Energy — west		1.4134	1.4935	1.5443

Notes: Energex data as at 10 August 2015. Ergon Energy data as at 5 October 2015. The size and complexity of Ergon Energy's distribution network results in a number of loss factors at different network levels across its area. The distribution loss factors are approved annually by the AER. To derive the total network losses, QCA (2013) calculated a combined loss factor for each TUOS region and pricing zone as a product of the load-weighted average marginal loss factors and Ergon Energy's published average distribution loss factors for each pricing zone, at the LV line level.

Sources: QCA 2013a; Energex and Ergon Energy website data.

Using this methodology, in 2013 the QCA calculated a single feed-in tariff of 7.55c/kWh but locational tariffs varied from 7.06c/kWh to 8.28c/kWh in the east zone and 10.92c/Kwh to 14.05c/kwh in the west zone.[260]

[260] QCA 2013a.

A number of submissions noted the limitations on locational pricing with a uniform tariff policy (UTP). The majority of stakeholders were against any mandatory form of locational based pricing while the UTP remains in place. For example, Stanwell Corporation said:

> *Stanwell does not consider that a mandatory feed-in tariff should vary due to location while the Uniform Tariff Policy remains active as it may counteract existing Government subsidies leading to regulatory arbitrage. Variations due to time should occur where these reflect the underlying value of solar PV exports, subject to the requirement that the FiT have complexity appropriate for the target market and administration.*[261]

A locational feed-in tariff should not be used to correct for distortions induced through the UTP, and any locational pricing would need to be carefully designed to ensure no unintended consequences arise from the subsidisation of retail prices while compensating solar PV owners based on their location. Retailers are best placed to make this assessment.

9.4.4 Review of the price approval regime

A price approval regime has sufficient flexibility to operate without the need for scheduled, ongoing review. Nevertheless, to ensure the price approval regulation remains fit for purpose, the Queensland Government should review the framework if, going forward:

- the QCA identifies a sustained market power problem, or concludes there is no ongoing market power issue; or
- market conditions change materially (for example, through competition or technological change).

As competition develops in regional Queensland, it will become increasingly important to ensure the regulatory framework is achieving its objectives without imposing unnecessary constraints. The QCA would be well-placed to advise government on any ongoing market power issues, or conversely, whether it considers the market has developed to a sufficient extent that the risks associated with excessive market power are no longer present. The emergence of new technologies and advanced metering could also have a significant impact on the suitability of price approval arrangements.

While unlikely to be an issue in the short term, the emergence of cheaper forms of embedded generation and renewable sources, such as fuel cells and energy storage, would provide greater choice for consumers, and may also trigger a review of the price approval regime.

9.5 What role for government?

Beyond the price approval regime for regional Queensland, the QPC has not identified a sound rationale for the state government to regulate or otherwise increase solar feed-in tariffs in Queensland. Moreover, the evidence suggests that while higher feed-in tariffs would benefit solar PV owners, they would come at a significant net cost to the Queensland community as a whole.

However, some stakeholders maintained that the Queensland Government had made a clear commitment to support solar PV and that this should translate into some form of higher price for solar exports.

[261] Stanwell Corporation Limited, sub. 30, p. 15.

In responding to such pressures, price regulation presents a superficially attractive option, in that it provides a tangible demonstration of government support; and any costs are off-budget and spread across a multitude of residential and commercial electricity customers.

However, the problems with such an approach are manifold. It conflates a potential 'means' (supporting solar PV) as desirable in itself as opposed to the coveted 'ends' (which relate to lower emissions, economic growth, and so on). The costs, in terms of the impact of higher electricity prices for businesses and households, lead to an unequivocal reduction in welfare for the Queensland community.

This inquiry has found that mandatory solar feed-in tariffs are not an effective or efficient means to achieve the desired environmental, economic and social outcomes. Alternative policies are more likely to achieve objectives at lower cost. For example, state governments have a range of other policy levers to consider to pursue environmental objectives. In addition to working in national fora to progress national policies that are more likely to achieve least-cost abatement, the Queensland Government is well-placed to pursue environmental objectives through:

- prioritisation of its R&D expenditures and funding of external R&D;
- to the extent that the balancing of a range of policy objectives allows, ensuring the price suppression effects of the UTP are minimised, which will increase the incentive to investment in solar PV;
- reducing regulatory burdens to low-emission technologies; and
- reviewing transport, planning, agricultural and other industry policies:
  - in particular, indirect and direct subsidies that may unintentionally result in emissions that are higher than would be the case absent the subsidies, without providing offsetting benefits to Queensland households and businesses.

Equally, as noted in Chapters 6 and 8, where there are potential gains to the electricity supply industry from solar PV investment, the government can ensure that the regulatory and market framework does not unnecessarily impede such investment from occurring.

Many of the issues raised during this inquiry relate to the efficiency and effectiveness of electricity policy and regulation more broadly, rather than solar PV specifically. Addressing those framework issues directly, rather than indirectly targeting them through feed-in tariff regulation, is likely to provide better outcomes for Queensland consumers.

If the government still wishes to provide an additional support to solar PV, then any program should be designed in the most cost-effective manner. This includes:

- targeting genuine additional abatement or investment, rather than redistributing income to existing solar investments or investments that would occur anyway;
- minimising distortionary impacts on the electricity market, including on other generation technologies;
- ensuring any program is time-bound and capped, and is monitored and subject to ongoing review; and
- providing funding through the budget, rather than recouping costs from electricity customers, to encourage:
  - more rigorous specification of program objectives and expected outcomes;
  - better evaluation and recognition of the opportunity cost of any program; and

– greater transparency and accountability with actual outlays identified in the budget papers.

How a program could be designed has not been considered as part of this inquiry, given the absence of evidence to suggest that the benefits of such a program would not outweigh the costs. However, assuming the objective is to increase solar PV uptake, then by way of example, an up-front capital subsidy may better target genuine additional investment in solar PV, as opposed to feed-in tariffs that largely go towards existing investments.

A capital subsidy will also reduce distortionary impacts on the electricity market (although not on the solar PV market). The alternative — a price subsidy based on energy production —including a flat c/kWh payment and a more sophisticated time or location-based payment, is likely to be far more costly to administer and fund, and risks increasing, rather than decreasing, distortions in the market.

Although a budget-funded program is unlikely to change the cost/benefit calculus of a solar PV subsidy, it encourages:

- more rigorous specification of program objectives and expected outcomes;
- better evaluation and recognition of the opportunity cost (for example, if funding is provided to support solar PV, then — in the absences of raising taxes — less will be available for health, education or community services); and
- greater transparency and accountability with actual outlays publicly identified in the budget papers.

A budget program is also consistent with the COAG National Principles for Feed-in Tariffs, which require any jurisdictional decision to legislate rights for micro generation consumers to receive more than the value of their energy must:

- be transitional in nature with clearly defined time limits and thresholds;
- establish the benefits and costs of any subsidy against the objectives of that subsidy (taking into account other complementary measures in place to support micro-generation consumers);
- give explicit consideration to compensation from public funds or specific levies rather than cross-subsidised by energy distributors or retailers; and
- not impose a disproportionate burden on other energy consumers without micro generation.

The AER has similarly raised concerns with recovery of jurisdictional scheme costs through network charges and how such costs should be recovered from customers, as the costs are not associated with providing distribution services.[262]

Budget funding is also likely to be more equitable than current arrangements which are resulting in low income earners bearing a disproportionate cost of higher electricity prices.

Similar to all budget proposals, it would be necessary to demonstrate that any budget program is the most appropriate, effective and efficient means of achieving the government's objectives and is consistent with the Charter of Fiscal Responsibility. Any proposed program should also build in monitoring from commencement and be subject to periodic evaluation in accordance with the Queensland Government's Evaluation Guidelines.

[262] AER 2010.

Recommendations

9.1 The Queensland Government should retain voluntary arrangements for feed-in tariffs in south east Queensland.

9.2 The Queensland Government should consider including solar feed-in tariffs in the annual price monitoring arrangements for the SEQ retail electricity market.

9.3 The Queensland Government should implement price approval regulation for solar exports from small customers in regional Queensland. Under the price approval process, regional retailers would be required to:

(a) purchase solar exports from small customers; and

(b) submit their offers to the Queensland Competition Authority (QCA) for approval on an annual basis.

The QCA must approve the offers unless they are materially inconsistent with efficient pricing principles. If the regulator does not approve the offers, it can request retailers submit revised offers for approval.

9.4 The Queensland Government should review the price approval regime if:

(a) the QCA identifies a sustained market power problem which continues despite the price approval regime in place;

(b) the QCA identifies that the potential for exercise of market power no longer exists; or

(c) market conditions change materially (for example, through competition or technological change).

9.5 This inquiry has not identified a case for the state government to regulate feed-in tariffs (or otherwise subsidise solar PV) outside establishing the price approval regime for regional Queensland. If the Queensland Government elects to intervene in the market to support solar PV, then any program should be designed to achieve its objective at least-cost, including by:

(a) targeting genuine additional abatement or investment, rather than redistributing income to existing solar investments or investments that would occur anyway;

(b) minimising distortionary impacts on the electricity market, including on other generation technologies;

(c) ensuring any program is time-bound and capped, and is monitored and subject to ongoing review; and

(d) funding any program through the budget rather than recouping costs from electricity customers, to encourage better evaluation and recognition of the opportunity costs, greater transparency and accountability, and lower adverse impacts on the least well-off.

ACRONYMS

A	
ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
C	
c/kWh	Cents per kilowatt hour
CCIQ	Chamber of Commerce and Industry Queensland
CEC	Clean Energy Council
CEFC	Clean Energy Finance Corporation
CER	Clean Energy Regulator
CO_2	Carbon dioxide
$CO_{2\text{-}e}$	Carbon dioxide equivalent
COAG	Council of Australian Governments
CS Energy	CS Energy Limited
CSO	Community Service Obligation
D	
DAPR	Distribution Annual Planning Report
DNSP	Distribution network service provider
E	
EEG	Germany's Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz)
EGWW	Electricity, gas, water and wastewater
Energex	Energex Limited
ERF	Emissions Reduction Fund
ESAA	Energy Supply Association of Australia
ESC	Essential Services Commission (Victoria)
F	
FiT	Feed-in tariff
FTE	Full-time equivalent
G	
GST	Goods and services tax
GW	Gigawatt
GWh	Gigawatt hour
H	
HHI	Herfindahl–Hirschman index
I	
IES	Inverter energy system
IPART	Independent Pricing and Regulatory Tribunal

IRR	Internal rate of return
K	
kV	Kilovolt
kVA	Kilovolt amp
kWh	Kilowatt hour
L	
LGA	Local government area
LGC	Large-scale Generation Certificate
LRET	Large-scale Renewable Energy Target
M	
MFP	Multifactor productivity
MRET	Mandatory Renewable Energy Target (forerunner of RET)
MTFP	Multilateral total factor productivity
MW	Megawatt
MWh	Megawatt hour
N	
NEM	National Electricity Market
NPV	Net present value
NSW	New South Wales
O	
OECD	Organisation for Economic Co-operation and Development
P	
PoE	Probability of Exceedance
Powerlink	Powerlink Queensland (Queensland Electricity Transmission Corporation Limited)
PPA	Power purchase agreement
PV	Photovoltaic
Q	
QCA	Queensland Competition Authority
QPC	Queensland Productivity Commission
R	
R&D	Research and Development
RAB	Regulatory asset base
REC	Renewable Energy Certificate
RET	Renewable Energy Target
RIS	Regulation Impact Statement
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
S	
SBS	Solar Bonus Scheme
SEQ	South east Queensland
SPPA	Solar power purchase agreement

SRES	Small-scale Renewable Energy Scheme
STC	Small-scale technology certificates
T	
TCP	Transmission connection point
TNSP	Transmission network service provider
ToU	Time of use
U	
UNEP	United Nations Environment Programme
USD	US Dollar
UTP	Uniform Tariff Policy
V	
VBRC	Victorian Bushfires Royal Commission

APPENDIX A: TERMS OF REFERENCE

Queensland Productivity Commission – Public Inquiry into a Fair Price for Solar Exports

Terms of Reference

Objective

The aim of the inquiry is to determine a fair price (or fair prices) for solar power that is produced at the home or business premises of a 'small customer' and exported into the electricity grid (both National Energy Market (NEM) connected and isolated grids). A fair price for exported solar energy:

- is to be determined based on an assessment of public and consumer benefits from solar generated electricity; and
- must not have an unreasonable impact on network costs for non-solar users.

Context

Solar power installations on small customers' premises can at certain times generate more electricity than is required by the customer resulting in the surplus electricity being exported into the local electricity grid. Payments to the customers for their exported solar energy are known as Feed-in tariffs (FiTs).

FiTs are currently available in different forms for small electricity customers (those consuming less than 100 megawatt-hours (MWhs) of electricity per year) across Queensland. In south-east Queensland (SEQ), FiTs are offered by participants in the competitive retail market, with no minimum amount mandated. There are currently six retailers in SEQ offering FiTs which range from 6 – 12c/kWh.

The *Electricity Act 1994* mandates a FiT for regional Queensland customers as there are no market FiTs available. The mandated FiT is determined annually by the Queensland Competition Authority, and is paid by Ergon Energy's retail business, and by Origin Energy in the case of Queensland customers connected to the New South Wales electricity network operated by Essential Energy (around the Goondiwindi/Inglewood region).

The regional FiT is based on the financial value to the electricity retailers from their receipt of exported solar energy. The FiT is calculated by summing the avoided generation costs, avoided NEM and ancillary service fees, and avoided costs of network losses. The regional FiT in 2015–16 is 6.3486c/kWh.

In addition, a large number of existing customers are in receipt of the now-closed 44c/kWh FiT under the Solar Bonus Scheme, for which the electricity distributors are responsible. Under the National Electricity Rules the distributors can recover the costs of paying the 44c/kWh FiT from all distribution network customers through the distributors' network tariffs.

The Queensland Government is also considering opportunities to grow the renewable energy sector in particular, the uptake of solar PV installation for both households and businesses. The Government has set a target for one million rooftops or 3000 MW of solar panels by 2020.

In addition, new emerging technologies such as battery storage at the household level, may over time, increase distributed energy generation. Battery storage together with smart metering also has the potential to reduce peak demand. A fair price for solar may also encourage households to use and see value in the network.

Scope

The Queensland Productivity Commission is to investigate and report to Government on:

- A methodology for determining a fair price for solar energy generated by a 'small customer' and exported to a Queensland electricity grid that:
  - is based on the public and consumer benefits of exported solar energy;
  - does not impose unreasonable network costs on electricity customers; particularly vulnerable customers; and
  - can be realised in the current electricity system.
- The price(s) for solar energy determined under the methodology.
- Any barriers or constraints (technical, market, regulatory or otherwise) to monetising the value of exported solar energy in Queensland in the current electricity system, and options to address those barriers.
- How the fair price (or fair prices) may be designed and paid (structure, unit measure, gross or net payment, payment mechanism).
- The mechanisms by which a fair price could be implemented in Queensland (mandatory or other).
- Appropriate review mechanisms and timeframes.

The scope does not include consideration of the 44c/kWh FiT rate under the Solar Bonus Scheme. This matter will be considered by the Commission's broad public inquiry into electricity prices.

In its investigations, the Commission should have regard to the following factors:

- The public and consumer benefits from exported solar PV generation, including social, economic and environmental benefits.
- Whether households and business are already fairly compensated for public and consumer benefits (such as through existing government renewable energy programs and rebates and market contracts).
- The existing tariff structures and the impact these are having on the market.
- The value / avoided costs and any cost imposed or benefits across the electricity supply chain due to the exported solar PV energy, taking into account temporal and geographical / locational factors. One example may be the value being recovered from consumers for use of the transmission network when exported energy is on-sold, where distributed solar energy does not utilise the transmission network.
- Whether the fair value for exported solar PV energy is sufficiently different between local areas or regions to justify the administrative costs to government or market participants of administering separate values for those areas/regions. This should include how different values could be implemented in conjunction with the Government's commitment to the Uniform Tariff Policy.
- Any additional cost that may be incurred by electricity customers from implementation of the fair prices/s recommended by the Commission.
- The perception of electricity customers about whether any cost to them resulting from the fair value is 'unreasonable'.
- Wherever possible that the entity receiving the benefit of exported solar energy should be the entity to pay for that benefit.
- Impacts on competition in the retail electricity market.

- Existing mechanisms in the electricity system which may prevent the true value of exported solar energy being realised/monetised (e.g. metering constraints preventing the premium value of daytime generation from solar PV being realised by retailers; the use of Net System Load Profile in NEM market settlement processes, etc.).
- The Government's 1 million rooftops target by 2020, noting that the Government is not intending to return to a premium tariff, and any FiT will be at significant discount to the retail cost of electricity.
- Any other matters the Commission considers relevant.

Resourcing

It is expected that the Commission will engage expert advice from external sources where necessary, including the support and expertise of the Queensland Competition Authority.

Timeframes

Issues Paper

The Commission must publish an issues paper outlining the issues associated with its investigation.

Draft Report

The Commission must publish a draft report on its investigation into a fair price for solar.

The Commission must publish a written notice inviting submissions about the draft report. The notice must state a period (the consultation period) during which anyone can make written submissions to the Commission about issues relevant to the draft report. The Commission must consider any submissions received within the consultation period and make them available to the public, subject to normal confidentiality considerations.

Final Report

The Commission must publish a final report on its investigation into a fair price for solar within 10 months of the start of the work.

Stakeholder engagement

The Commission should consult with stakeholders, and consider submissions, within the specified timeframes.

APPENDIX B: CONSULTATION

Submissions

Individual or organisation	*Submission number*	
	Issues paper	*Draft report*
AGL	19	DR14
Andrew Gray		DR02
APA Group	26	DR07
Australian Energy Council		DR09
Australian Gas Networks	36	DR21
Australian Solar Council, Energy Storage Council	38	DR23
Brian Haber (confidential)	44	
Bruce Cooke	23	
Caroline Slager	08	
Chamber of Commerce and Industry Queensland	21	DR18
David Brooker	42	
David Warner	13	
Don Willis	16	DR06
Dr Peter Hale	22	
Energex	33	DR17
Energy Australia	25	DR16
Energy Networks Association	41	DR20
Energy Retailers Association of Australia	31	
Energy Supply Association of Australia	37	
Ergon Energy Corporation	34	
Ergon Energy Queensland	35	
Ergon Energy Corporation & Ergon Energy Queensland		DR22
Ernest Priddle	05	
Frank Ondrus	07	DR03
Gary Reid	06	
Gregory Adams		DR13
Harold Edmonds	03	
Harold Gossner	12	
Harold Turnbull	01	
John Davidson	17	
John Sheehan	20	DR10
Judy Whistler	29	
Julie Davies	14	
Mark Tranter	10	
Master Electricians Australia	15	
Michael Mokhtarani	04	
Origin Energy	24	DR15

Individual or organisation	*Submission number*	
	Issues paper	*Draft report*
Peter Boikowski		DR01
Project Brainstorm	11	
Queensland Futures Institute		DR08
Queensland Conservation Council	39	
Queensland Farmers Federation		DR05
Queensland Government — Minister for Main Roads, Road Safety and Ports, and Minister for Energy and Water	40	
Queensland Resources Council	27	DR12
Ralph Carlisle	02	
Red Energy and Lumo		DR11
Richard Vanstone	09	
Simply Energy		DR19
Solar Citizens	18	DR24
Stanwell Corporation Limited	30	DR04
Stephen Read	43	
Sustainable Queensland	32	
University of Queensland, Global Change Institute	28	

Consultations

PUBLIC HEARINGS — Presentations

Townsville — Monday, 2 November 2015

Presenters
Debra Burden, Canegrowers Burdekin
Tracey Lines, Townsville Enterprise
Mark Kelly, James Cook University
Greg Dawes, Pioneer Valley Water
Dr Ahmad Zahedi, James Cook University
Douglas McPhail, Ergon Energy

Townsville — Tuesday, 12 April 2016

Presenters
John Debbins
Jewel Vercoe Rainbow — NQ Publicity

Brisbane — Thursday, 5 November 2015

Presenters
Reg O'Dea
Chas Brown, Skillstech
John Davidson
Benjamin Jones, Expert Electrical
Jonathan Pavetto, Alliance of Electricity Consumers
Tennant Reed, The Australian Industry Group

Brisbane — Monday, 4 April 2016

Presenters
Natalie Walsh, MS Queensland
Carly Hyde, QCOSS
Bruce Cooke
Brian Clark, Queensland Conservation Council
James Baxter
Andrew Furlong

Toowoomba — Tuesday, 5 April 2016

Presenters
Michael Murray, Cotton Australia
Mark Tranter, Alternative Technology Association
Frank Ondrus, Householders' Options to Protect the Environment (HOPE) Inc.

Bundaberg — Thursday, 7 April 2016

Presenters
Dale Holliss, Bundaberg Canegrowers

Rockhampton — Monday, 11 April 2016

Presenters
Chris Hooper

Cairns — Thursday, 14 April 2016

Presenters
Phil Pollard, Cairns and District AIR
Sharon Denny, Australian Sugar Milling Council

PUBLIC FORUMS

Toowoomba — Thursday, 12 November 2015

Rockhampton — Tuesday, 17 November 2015

Mt Isa — Wednesday, 18 November 2015

Cairns — Thursday, 26 November 2015

Mt Isa — Wednesday, 13 April 2016

ROUNDTABLES

Bundaberg — Thursday, 15 October 2015

Organisation	*Representative*
Dobinsons Springs and Suspension	Glen Dobinson, Family Business Owner
Bundaberg Sugar	David Pickering, General Manager Operations
Bundaberg Walkers Engineering	Enio Troiani, General Manager
CANEGROWERS Bundaberg	Dale Holliss, CEO/Manager
SunWater	Tony Reynolds, Service Manager Bundaberg
Bundaberg Regional Council	Cr Mal Forman, Mayor
Ergon Energy Corporation Limited (Distribution)	Jenny Doyle, Group Manager Regulatory Affairs
Ergon Energy Queensland (Retail)	Mark Williamson, General Manager Wholesale Markets

Consumer — Tuesday, 27 October 2015

Organisation	*Representative*
AGL Energy	Patrick Whish-Wilson, Regulatory Economist
Australian Energy Market Commission	Chris Spangaro, Senior Director, Retail and Wholesale Markets
Chamber of Commerce and Industry Queensland	Julia Mylne, Policy and Advocacy Advisor

Organisation	Representative
Council on the Ageing (COTA)	John Stalker, Program Coordinator Capacity Building, COTA Queensland
Energex	Andrew Hager, Group Manager, Strategic Customer Interactions
Energy and Water Ombudsman Queensland	Forbes Smith, Energy and Water Ombudsman
Energy Consumers Australia	Rosemary Sinclair, Chief Executive Officer
Energy Retailers Association of Australia	Alex Fraser, Interim Chief Executive Officer
Energy Supply Association of Australia	Shaun Cole, Policy Advisor
Ergon Energy Corporation Limited (Distribution)	Jenny Doyle, Group Manager, Regulatory Affairs
Ergon Energy Queensland (Retail)	Brett Milne, Group Manager, Customer and Marketing
Origin Energy	Sean Greenup, Manager Energy Regulation Retail
Queensland Council of Social Service	Carly Hyde, Manager, Essential Services

Renewable — Thursday, 29 October 2015

Organisation	Representative
Australian Solar Council	Steve Blume, President
Chamber of Commerce and Industry Queensland	Julia Mylne, General Manager, Advocacy
Clean Energy Council	Darren Gladman, Policy Manager
Energy Supply Association of Australia	Shaun Cole, Policy Advisor
Energy Networks Australia	Lynne Gallagher, Executive Director, Industry Development
Energy Retailers Association of Australia	Andrew Lewis, General Manager, Regulation and Policy
University of Queensland	Craig Froome, Program Manager, Clean Energy

Emerging technologies — Thursday, 31 March 2016

Organisation	Representative
AEMC	Chris Spangaro
AEMO	Matt Zema
AER	Mark Wilson
AGL	Stephanie Bashir
CSIRO	Mark Paterson
Department of Energy and Water Supply	Paul Simshauser
Energex	Kevin Kehl
Energy Consumers Australia	David Havyatt
Ernst & Young	Matthew Rennie
Greensync	Skye Holcombe Henley
Lyon Infrastructure	Vanessa Sullivan
Sunverge Energy Australia	Richard Schoenemann
University of Queensland	Peta Ashworth
University of New South Wales	Iain MacGill

Organisation	*Representative*
University of Sydney	Penelope Crossley

CONSULTATIONS AND VISITS

Regional Queensland

Bundaberg —14–16 October 2015

Ergon Energy

Ergon Energy

- Emerick Farms, Alloway
- Austhcilli, Alloway

Bundaberg Sugar

Bundaberg Walkers

CANEGROWERS

- Cayley Farm

Community service groups

- Ozcare
- Regional Housing Limited
- Salvation Army

Financial Counselling

Townsville — 2–3 November 2015

Ergon Energy (Retail)

Ergon Energy (Solar and battery trial briefing)

Stakeholder meeting

- Townsville Enterprise
- Australian Sugar Milling Council
- Queensland Farmers Federation
- Ergon Energy
- James Cook University

Consumer groups

- St Vincent de Paul Society

Sun Metals

Toowoomba — 12–13 November 2015

Wamara cotton farm

- Queensland Farmers Federation

Ergon Energy — Energy Savers Plus Program

University of Queensland, Gatton Campus

Solar PV research facility

Mt Isa — 17–18 November 2015

Mt Isa City Council

Stanwell (Mica Creek Power Station)

Diamantina Power Station

Cairns — 26–27 November 2015

FNQ Regional Organisation of Councils

Regional Development Australia FNQ and Torres Strait

Association of Independent Retirees

Small Business meeting

Northern Iron and Bass Foundry

Northqual Produce

Cattle council of Australia

Gorge Creek Orchards, Mareeba

- Mareeba Fruit and Vegetable Association
- CANEGROWERS

Banana Growers Council

Brisbane

Government

Department of Energy and Water Supply

Department of the Premier and Cabinet

Queensland Treasury

Queensland Treasury Corporation

Queensland Competition Authority

Victorian Essential Services Commission

Western Australian Public Utilities Office

Other organisations

Australian Energy Market Commission

Australian Energy Market Operator

Australian Solar Council

Energex Lmited

Energy Consumers Australia

Energy Retailers Association of Australia

Energy Supply Association of Australia

Ergon Energy

Powerlink

University of Technology Sydney

APPENDIX C: INTERSTATE AND INTERNATIONAL FEED-IN TARIFFS

Interstate feed-in tariffs

As discussed in Chapter 2, most Australian jurisdictions followed a similar path to Queensland, introducing premium feed-in tariff schemes that were subsequently closed or abolished. A range of arrangements replaced premium schemes, from full deregulation to regulated feed-in tariffs based on an avoided cost approach. Some notable features and recent trends are highlighted below.

New South Wales

New South Wales initially offered a gross feed-in tariff of 60c/kWh from 1 January 2010, before lowering it to 20c/kWh in late 2010 as uptake accelerated. As the costs of their premium feed-in tariff scheme continued to rise, the NSW Government issued a declaration to close access to the scheme, with payments to existing claimants ending in 2016. The NSW Government also implemented actions to limit the cost of the scheme through a mandatory retailer contribution, where retail businesses are required to contribute 5.2c/kWh to the cost of the scheme.

In 2011, the NSW Auditor-General reviewed the scheme and found it was poorly planned and designed, and implemented with no risk management and limited operational controls. The cost of the seven-year scheme was estimated at $1.05 to $1.75 billion.[263]

After closing the scheme, the state introduced a deregulated market for feed-in tariffs, where solar PV owners choose feed-in tariffs offered by retailers. The Independent Pricing and Regulatory Tribunal (IPART) publishes a voluntary ‘benchmark’ feed-in tariff each year to provide pricing information and help consumers compare market offers. The benchmark provides an estimate of the subsidy-free value of solar PV exports using the ‘wholesale market value’ method.

Victoria

Victoria treats the electricity market and the feed-in tariff market differently — electricity contracts for small customers are deregulated and have been since January 2009, while feed-in tariffs continue to have a regulated floor price.

The Victorian Government regulates a floor price for solar PV exports each year through the Essential Services Commission (ESC). This price is set with regard to an ‘avoided cost’ methodology. Similar to IPART’s benchmarking approach and the QCA’s regional feed-in tariffs, the ESC has regard to wholesale electricity prices, and avoided distribution and transmission losses.[264]

In 2015, the Victorian Government asked the ESC to undertake an inquiry into the true value of distributed generation, including solar PV, with the aim to:

- examine the value of distributed generation including the value of distributed generation for the wholesale electricity market, network infrastructure and environment;
- assess the adequacy of the current policy and regulatory frameworks governing the remuneration of distributed generation for the identified value it provides; and
- make recommendations for any policy and/or regulatory reform required to ensure effective compensation of the value of distributed generation in Victoria.

[263] Audit Office of New South Wales 2011.
[264] ESC 2014, p. 10.

The terms of reference excludes any consideration of whether feed-in tariffs should be deregulated, and any consideration of the policy and regulatory frameworks that govern connections.

The draft report, released 6 May 2016, recommended moving away from paying solar system owners a flat rate for the power they generate. It recommended introducing regulated time-varying feed-in tariffs for peak, shoulder and off-peak times. This concept has been explored in a Queensland context in Chapter 8 of this final report. Box 29 provides a summary of the ESC's draft report recommendations.

Box 29: ESC Distributed Generation Inquiry Draft Report — Energy Value[265]

The Distributed Generation Inquiry Draft Report — Energy Value, sets out the ESC's draft findings and recommendations with regard to the energy value of distributed generation.

Summary of recommendations

1. Basis for calculating the feed-in tariff — The feed-in tariff is to be calculated annually, having regard to wholesale market prices and avoided costs.
2. Eligibility for FiT payments — Eligible technologies are solar PV, hydro, wind and biomass, up to generating capacity of 100kW.
3. Multi-rate feed-in tariffs — The current single tariff should be replaced by time and location tariffs reflect the wholesale price of electricity.
4. Time-varying feed-in tariffs — Time-varying feed-in tariffs to include critical peak, peak, shoulder and off-peak.
5. Locational feed-in tariffs — Victoria to be divided into two regions to reflect the different average line losses across the state.
6. Fully reflective feed-in tariff — If the retailer is able to offer a feed-in tariff that fully reflects the half hourly prices in the wholesale market, this may suspend retailer's obligation to offer the regulated feed-in tariff rates.
7. The environmental and social value of distributed generation — The environmental and social value of distributed generation should be reflected in a deemed output tariff that is paid to a distributed generator based on the deemed output of the distributed generation system.
8. The value of avoided emissions — The deemed output tariff for 2017 should be calculated to account for the value of the greenhouse gas emissions avoided as a result of distributed generation displacing the marginal generator in the wholesale electricity market.
9. Minimum tariffs — The regulated tariff structure should continue to impose a minimum obligation on retailers.
10. Reviewing tariffs — The value of the feed-in tariff and the deemed output tariff should be reviewed annually.
11. Reviewing the tariff structure — The time block structure and location zones of the flexible feed-in tariff, once established, should remain unchanged for an appropriate period.

Western Australia

Western Australia differs from south east Queensland, New South Wales and Victoria in that both its feed-in tariffs and its electricity prices are regulated. In this respect, Western Australia is similar to regional Queensland, where retail prices and feed-in tariffs are also regulated.

After the premium scheme was closed in Western Australia, the government introduced a requirement for retailers, Synergy and Horizon Power, to buy solar exports with prices approved by the government's Public Utilities Office. Under the scheme, Synergy offers single feed-in tariff of 7.135c/kWh. Horizon Power, which services regional areas, has location-based pricing. Horizon Power publishes a list of towns, along with the power buyback rate and how much managed and unmanaged distributed generation each town's network can host. Buyback rates range from 7 to 50c/kWh (see Chapter 9).

International feed-in tariffs

At the beginning of 2015, almost 80 countries had some form of feed-in tariff. The variety of schemes in place does not allow direct comparison of feed-in tariff rates and schemes. However, some interesting

265 Essential Services Commission 2016, The Energy Value of Distributed Generation, Distributed Generation Inquiry Stage 1 Draft Report, April 2016.

outcomes and trends in Germany, Spain, and the United States of America are noted below. Germany is of interest because of its status as 'first-mover' in terms of residential solar, Spain because of the extraordinary boom–bust cycle its feed-in tariff provoked in 2007–08, and the United States of America because of the range of feed-in tariff schemes that differ from state to state.

Germany – a first mover

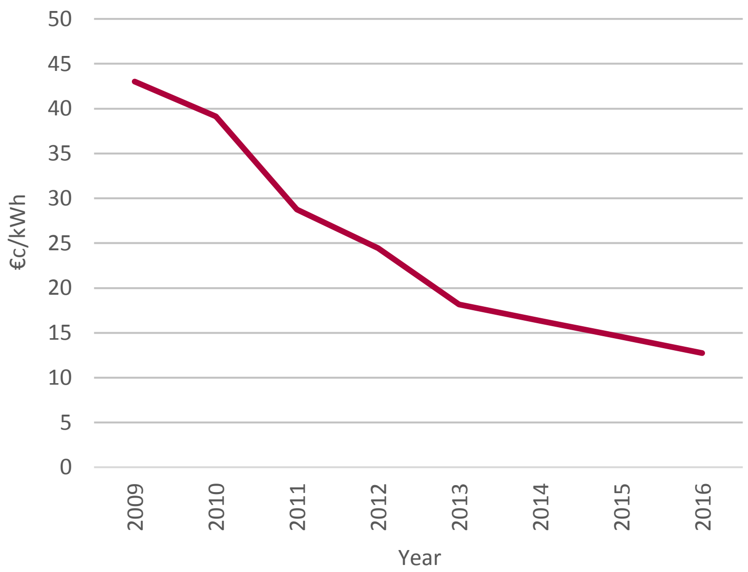
In 1990, Germany adopted its Stromeinspeisegesetz (StrEG), which roughly translates as 'electricity feed-in law'. This policy covered several technologies with specific rates for solar, wind, hydropower, biomass and landfill or sewage gas.

Germany's feed-in tariff is a cost-based tariff, where investors in renewables must receive sufficient compensation to provide a return on their investment (ROI) irrespective of electricity prices. In Germany, the target ROI is generally around five to seven per cent.

From 1991 to 1999 the rates for solar and wind fluctuated between 8.45 and 8.84€c/kWh.[266] The *Renewable Energy Sources Act 2000* (Erneuerbare-Energien-Gesetz (EEG)) raised the solar feed-in rate from 8.53 to 50.62€c/kWh with a cap of 350 MW installed capacity. This cap was raised in 2002 to 1000 MW installed capacity. The costs incurred are spread evenly among the distribution providers and passed on to all German electricity users (referred to as the EEG surcharge).

Under the EEG, plant operators receive a 20-year, technology specific feed-in price. The EEG regularly reduces the value of the feed-in tariff offered to new entrants. As shown in Figure 61, the average feed-in tariff for new PV installations has fallen consistently over the years. This price degression aims to drive efficiency in new technology development and deployment, and reduce the average feed-in tariff as more systems connect to the grid. The current feed-in tariff for new installations is approximately 12.75€c/kWh for small systems under 10 kW.

Figure 61: Solar PV feed-in tariffs in Germany up to 10 kW



Source: Fraunhofer ISE 2015.

[266] Davies & Allen 2014.

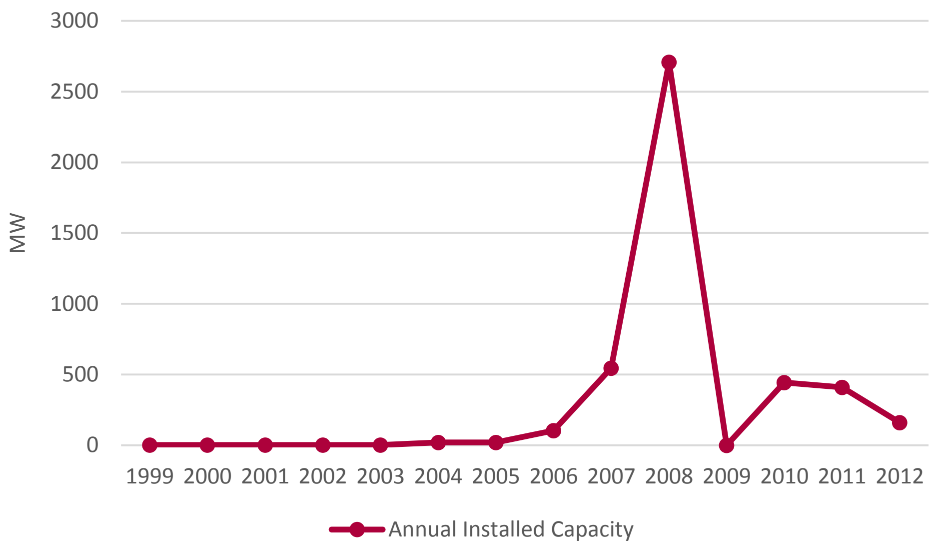
The total EEG cost for 2016 is estimated at €22.9 billion and the EEG surcharge has been set at 6.354€c/kWh[267], which represents approximately 21 per cent[268] of a typical household bill.[269] The surcharge is equivalent to about €280 per person per year.

Spain – boom and bust

In 2007 and 2008, in large part due to a generous feed-in tariff (up to 34€c/kWh for systems up to 20 kW)[270] and generous contract terms (up to 25 years), Spain experienced extraordinary growth in solar PV systems (Figure 62). In 2008–09, 2708 MW of capacity was installed, which far exceeded the goal of 371 MW.[271]

The total annual cost was in excess of €2.5 billion, which represented over 50 per cent of all spending on renewable energy, but produced approximately 12 per cent of the total renewable electricity generation.[272]

Figure 62: Spain's annual installed solar PV capacity (MW), 1999–2012



Source: Global Subsidies Initiative & International Institute for Sustainable Development 2014.

Like in Germany, feed-in tariffs were offered on a long-term contract (25 years), although a difference with Germany was that there was no opportunity to decay the feed-in tariffs along with decreases in the price for solar PV installations.

Due to the massive oversubscription, a moratorium was put in place in October 2008 to control growth, with no installations conducted during 2009.[273]

Feed-in tariffs were reduced in mid-2008, and further cuts to the feed-in tariffs made in 2010 were applied retrospectively to existing installations. In 2014, the Spanish Government completely suspended renewables projects from receiving their contracted feed-in tariffs.[274]

[267] Lang & Lang 2016.
[268] Fraunhofer ISE 2015.
[269] Based on a three-person household with an annual power consumption of 3500 kWh paying roughly 29€c/kWh in 2014.
[270] Agencia Estatal Boletin Oficial Del Estado 2008.
[271] Global Subsidies Initiative & International Institute for Sustainable Development 2014; CEC 2015a.
[272] Global Subsidies Initiative & International Institute for Sustainable Development 2014.
[273] International Energy Agency (IEA) 2015; Global Subsidies Initiative & International Institute for Sustainable Development 2014.
[274] International Energy Agency (IEA) 2015.

United States of America – many states, many approaches

Like Australia, the United States of America (USA) has multiple jurisdictional approaches. Table 33 outlines six different state schemes, with eligible generation technologies ranging from solar PV to solid waste.

Feed-in tariff approaches vary from the 9c/kWh avoided cost to the 54c/kWh regulated premium feed-in tariffs, similar to the existing spread in Australia between the semi-regulated and market feed-in tariffs and the legislatively set premium feed-in tariffs. Interestingly, there is a far greater spread of contract terms than is evident in Australia, with both net and gross metered installations being favoured in different states, and contract terms varying markedly; for example, terms are reset annually (Texas), terms are five years (Georgia) or terms are 25 years (Vermont).

Table 33: Solar schemes in the United States of America

	Eligible technologies	*Project size caps*	*Program caps/targets*	*Contract duration*	*Price*
California Feed-In Tariff Public Utilities Code §399.20 Public Resources Code §25741	Solar PV, wind, geothermal, fuel cells using renewable fuels, small hydroelectric (≤ 30 MW), biomass, municipal solid waste conversion, landfill gas, ocean wave, ocean thermal, tidal current	Up to 3 MW	750 MW Additional 250 MW from bioenergy (biogas and biomass) projects that begin after 6/1/2013	10, 15 or 20 years	Market-based tariff rate
Hawaii Feed-In Tariff	Solar thermal electric, PV, landfill gas, wind, biomass, hydroelectric, geothermal electric, municipal solid waste, tidal energy, wave energy, ocean thermal	Up to 5 MW, though cap varies by technology and island	Oahu – 60 MW Big Island – 10 MW Maui, Lanai, and Molokai (combined) – 10 MW	20 years	$0.12/kWh to $0.269/kWh, depending on project technology and size
Oregon Solar Volumetric Incentive and Payments Program (Pilot Program) or Administrative Rules 860-084	Solar PV	Up to 500 kW	25 MW New applications will not be accepted after March 31, 2015, or 25 MW cap is reached, whichever is earlier	15 years	Larger projects (>100 kW) must set rates according to a competitive bidding process Smaller projects - $0.18/kWh to $0.39/kWh, depending on project location and size
Rhode Island Distributed Generation Standard Contracts RI General Laws Ch. 39-26.1-3 (H5803 – 2013) and 39-26-5	Solar thermal electric, PV, wind, geothermal, fuel cells using renewable resources, biogas as a result of anaerobic digestion, small hydroelectric, tidal energy, wave energy, ocean thermal	Up to 5 MW	40 MW Program expires at the end of 2014	15 years	$0.1480/kWh to $0.2995/kWh, depending on project technology and size
Vermont Standard Offer for Qualifying SPEED Resources 30 V.S.A. §8005a	Solar PV, landfill gas, wind, biomass, hydroelectric, municipal solid waste, anaerobic digestion, small hydroelectric	Up to 2.2 MW	127.5 MW	10–25 years	Rates determined by a market-based bidding subject to an avoided-cost cap. Avoided-cost cap ranges from $0.090/kWh to $0.257/kWh depending on project technology and size
Washington Renewable Energy Cost Recovery Incentive Payment Program RCW 82.16.110 WAC 458-20-273	Solar thermal, PV, wind, anaerobic digestion	Up to 75 kW	Not specified	Not specified	$0.12/kWh to $0.54/kWh, depending on technology type and in-state manufacturing $0.30/kWh to $1.08/kWh (community solar projects), depending on in-state manufacturing Single customers may not receive more than $5000 per year

Source: Reproduced from the Office of Policy and Legal Analysis, accessed at <http://maine.gov/legis/opla/FITStatetabledetail.pdf> on 20 January 2016.

APPENDIX D: SOLAR PV FINANCIAL RETURN AND COST OF ABATEMENT

This appendix provides background information on the data used to analyse the financial returns to investment in solar PV systems, and discusses the sensitivity tests presented at various points in the body of the report. It also presents sensitivity tests on the costs of abatement.

Background to the data

ACIL Allen was contracted to provide supporting modelling work for this inquiry and the QPC's Electricity Pricing Inquiry. Most of the data used to estimate the financial returns to investment in solar PV systems is derived from the ACIL Allen Report.

System costs

Solar PV system price data was obtained using a number of data sources and calculations to produce a time series of both gross and net system prices. Key data sources and steps included:

- Brisbane prices as at July 2015 by rated system size were sourced from SolarChoice.[275] The prices are an estimate of the average cost of installing a solar PV system net of the subsidy provided by small-scale technology certificates (STCs).
- Metering installation costs were added to the net system prices based on published distributor data.
- The net system prices were then projected backwards from 2015–16 using an ACIL Allen index of the national average historic cost of installing a PV system (which were based, in turn, on data drawn from AECOM and SolarChoice).[276] ACIL Allen data on state and territory system price premiums and discounts from the national average were used to adjust the series to represent Queensland prices over time. The system costs exclude rebates, subsidies (STCs and RECs) and GST.
- System cost projections to 2034–35 were based on the assumptions used by ACIL Allen in its modelling for the QPC. ACIL Allen assumed that the cost of installing a PV system in Australia in real terms will decrease by 50 per cent by 2050 and remain constant thereafter. Given the assumed inflation rate of 2.5 per cent, this implies that system installation costs will remain roughly constant in nominal terms.
- To form gross system prices, the net system prices by system size (excluding subsidies and taxes) were 'grossed-up' based on information from SolarChoice for April 2014, which showed system prices by size with and without the STCs subsidy. GST was also added.

Financial benefits

Under a net metering arrangement, a solar PV system provides two financial benefits:

- For each kilowatt hour exported, the system generates revenue equal to the feed-in tariff.
- For each kilowatt hour generated and not exported — that is, consumed on premises — demand for electricity from the grid is reduced so that the amount of money paid to an electricity retailer is reduced by the variable component of the retail tariff.

To calculate the financial benefits of a solar PV investment, the following data projected to 2034–35 was used:

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[275] SolarChoice 2015.
[276] ACIL Allen Consulting 2014, pp. A42–43.

- wholesale energy prices;
- retail energy prices with a split between the fixed component of retail tariffs and the variable component;
- line losses; and
- the price of STCs.

To calculate the revenue generated through feed-in tariffs, the following information was used:

- an estimate of generation volumes — The QPC calculated these based on the specific scenario under investigation. For example, estimated generation volumes varied according to the rated output of the system and where the system was installed in Queensland (postal zones one to four); and
- the rate of export based on ACIL Allen data for average export rates by system size — These export rates were checked against Energex and Ergon Energy (Network) data.

To calculate the financial savings from importing less electricity from the grid, the following information was used:

- an estimate of generation volumes;
- average export rate data;
- using the above data, an estimate of the volume of electricity generated and used on premises; and
- the variable component of the retail tariff to be multiplied by the volume of solar electricity used on premises.

Key features of the data affecting estimated financial returns

A number of trends captured in the data have an important impact on the estimated financial returns to solar investment:

- the price trajectory of system prices — If system prices do not decline as rapidly as projected, then the future returns to investment will be less (all other factors held constant);
- re-balancing of network tariffs — Modelling assumed that retail tariffs become more cost-reflective over time through a re-balancing of network tariffs. Basically, a larger share of the revenue is obtained through fixed charges and a lesser share through variable or consumption charges. The variable component of the retail tariff is projected to decline over time, thereby reducing the savings achieved by solar owners when they consume less electricity from the grid (discussed in Chapter 2); and
- higher wholesale energy prices — Wholesale energy prices are projected to increase relative to recent years. As changes in wholesale energy prices drive feed-in tariffs based on the avoided cost methodology, market driven feed-in tariffs are projected to increase providing a financial benefit to solar owners.

Given that the financial returns to investment are calculated over either 20 or 25 years (the assumed useful life of the panels), these trends have a significant influence on the investment returns for both existing and new systems.

Measures of the financial return to investment

The financial returns to investment were measured by calculating:

- the internal rate of return (IRR) — the discount rate that results in the net present value (NPV) of system costs (cash outflows) being just equal to the NPV of financial benefits (cash inflows) generated by the system; and

- the number of years required for the investment to break even, based on discounted cash flows.

Results in this report are presented using discount rates varying between zero and 10 per cent. It is necessary to discount costs and benefits occurring later relative to those occurring sooner, since money has an opportunity cost — money received now can be invested and converted into a larger future amount (Box 30). In weighing the decision to invest in solar or not, most households would choose a discount rate between 5 and 10 per cent (nominal). However, some households might choose a lower discount rate if they are motivated by considerations other than the financial returns to investment.

In practice, as the costs of the purchase and installation of the solar PV system occurs all in the initial year, it is just the revenues generated by feed-in tariffs and the savings from importing less from the grid that are discounted.

Box 30: Discounting the costs and revenues of solar PV systems

Private time preference rate and social time preference rate

Most individuals prefer present to future consumption — commonly referred to as 'time preference', which is measured by the real interest rate on money borrowed or lent. The rate at which individuals are willing to trade present for future consumption is known as the 'private time preference rate' (PTPR). Suppose that, in present day prices, an individual requires $103 next year in return for giving up $100 now, then their real private time preference rate is three per cent. A method closely related to the PTPR is the Social Time Preference Rate (STPR). The STPR represents society's preference for present against future consumption. One of the major differences between the two methods is that the STPR is measured from a society perspective, while the PTPR is measured from the perspective of an individual. It should also be noted that the STPR may allow for inter-generational values that are not measured by the PTPR and the rate tends to be lower than the PTPR. Discounting using the PTPR or the STPR is appropriate where the costs and benefits are measured in terms of consumption.

Social opportunity cost of capital

In most cases, making an investment implies giving up one or more other investments. The value given up is the social opportunity cost of capital. This reflects the rate of return on the investment elsewhere in the economy that is displaced by the proposal (rather than consumption discount rate). In other words, it is the return forgone by implementing a proposal.

Implied discount rates and modelling of household solar investment behaviour

While it is highly unlikely that a typical household or small commercial entity would formally apply a discount rate to assess the financial implications of a PV installation, consumer behaviour strongly supports the idea that early paybacks or upfront subsidies that reduce 'out of pocket' costs have a strong impact on installation rates. Accordingly, it is also reasonable to assume that consumer behaviour will be related to discounted financial returns rather than, say, undiscounted financial returns.

ACIL Allen, rather than adopting a particular assumed discount rate, tested a range of discount rates from 7.5 per cent through to 15 per cent, in an attempt to find the rate which best explained the level of historical uptake actually observed. The rate which provided the best fit with the historical data was a discount rate of 10 per cent nominal.

Source: Department of Finance 2006, p. 23; ACIL Tasman 2011, p. 25.

Optimistic or conservative?

The financial returns to solar PV investment can be calculated under many different scenarios and sets of assumptions. Some examples include:

- the location of the investment in Queensland — the same system in different locations generates different volumes of electricity;
- the specific conditions under which the installation occurs — for example, the presence of shade, roof tilt and the direction the roof faces;
- the price of the installed system — particularly as it may vary across Queensland or vary by component manufacturers;
- all of the assumptions used in modelling and projecting price paths to 2034–35 — for example, wholesale energy prices and retail prices;

- the assumed useful life of the panels; and
- export rates — vary by household characteristics (for example, the ability of households to shift consumption patterns to maximise the financial benefits achieved from their solar investment).

Investment returns presented in the body of the report are mainly based on 'conservative' assumptions so that for the 'average' case the returns should be 'at least' as large as those presented if all assumptions and projections hold true.

- It was assumed that the useful life of panels is 20 years. If a household's panels last longer, then this will raise the financial return. Therefore, assuming 20 years provides a conservative estimate of the returns to investment. However, the 'extra' financial benefits in outer years are discounted and therefore have a relatively minor impact on the return to investment.
- The estimated volumes of electricity generated by a system are often about 10 per cent below those typically used by online calculators. Some households will achieve greater volumes of electricity from their panels and therefore achieve a higher financial return. However, many installations are less than 'ideal' and will generate much less than the maximum volume their systems are capable of under different circumstances. In addition, estimated returns do not incorporate any decay in the efficiency of panels and maintenance costs were assumed to be zero (although sensitivity testing of returns to these factors was separately undertaken). In this way, the somewhat conservative generation volumes help offset these latter factors.
- Tariff rebalancing is included in base case assumptions used throughout this report, and suppresses the returns to investment.

An allowance for inverter replacement was not included in the financial return calculations from Chapter 4 onwards. This may introduce an upward bias to the estimated financial returns. Under base case assumptions, an investment in a 3.0 kW system (postal zone 3) in 2015–16 produces an estimated internal rate of return of 13.3 per cent with a payback period of 10 years using a discount rate of six per cent. Assuming an inverter cost of $1200 in 2015–16 dollars and inverter replacement at 15 years, the internal rate of return is decreased to 12.7 per cent and the payback period is increased to 13 years. These calculations assume a module useful life of 20 years (which is conservative as discussed above). If the useful life is 25 years, then the internal rate of return is increased from 12.7 per cent to 13.5 per cent (slightly higher than the base case return at 13.3 per cent).

The financial calculations made in the body of the report are based on modelling which used data from the AER's preliminary regulatory determination for Ergon Energy (Network) and Energex. Using data from the final determination, retail prices are on average 4.2 per cent higher over the period to 2034–35. The buyback rate (based on avoided costs) is only 0.5 per cent higher on average. The new data would not have significant impacts on results:

- the financial savings a household makes from reducing imports would be marginally greater, as the gap between the retail price and the solar export price is higher. This would reduce the payback periods slightly;
- investment in solar PV under the base case would be marginally higher;
- marginally higher investment would lead to an increase in the aggregate subsidy paid to solar households through the SRES capital subsidy; and
- the subsidy provided through the lesser contribution of solar households to network costs relative to solar households would increase marginally.

Net vs gross metering arrangements

A net versus gross metering arrangement has significant implications for the level of financial benefit that households receive from their solar PV investments. All of the financial returns presented in the body of the report assume a net metering arrangement continues to apply.

If a feed-in tariff is greater than the variable component of the retail electricity tariff, then a solar household will benefit from being on a gross metering arrangement. For example, households in the Solar Bonus Scheme receive 44c/kWh exported (or 44 cents plus a market feed-in tariff of between 6 and 10 cents in south east Queensland). The variable component of residential Tariff 11 is roughly 22c/kWh in 2015–16. At all volumes of generation and exports, it is always better for the household if their kilowatt hour earns 44 cents rather than being used as an offset against imports under a net metering arrangement where it provides a savings of 22 cents.

However, if a feed-in tariff is below the variable component of the retail tariff, then a net metering arrangement is better for households. Under a net metering arrangement, the proportion of generation that is exported will receive the feed-in tariff. However, generation that is used for own consumption and reduces imports from the grid results in savings to the household at the higher rate of variable component of the retail tariff.

For example, with a feed-in tariff of 6–10c/kWh, the household is better off if its generation is used as an offset to reduce imports from the grid. Under a gross metering arrangement, each kilowatt hour exported would earn 6–10 cents, while the household simultaneously imports from the grid at 22c/kWh. Under a net arrangement, each kilowatt hour generated and used for consumption reduces energy demanded from the grid and saves the house 22 cents.

Table 34 provides a comparison of the financial benefits to a household under gross and net metering when the feed-in tariff is well below the variable component of retail tariffs (which is the case under existing arrangements and market conditions). A system which produces 6000 kWh in a year will, under a gross metering arrangement, earn $360 (6000 kWh multiplied by 6 cents, then converted to dollars). Under gross metering, the installation of a solar PV system has no impact on metered imports from the grid. Therefore, the total financial benefit to the household is $360 in that year.

Table 34: Financial impacts of net versus gross metering

Assumptions		
Prices (c/kWh)	Feed-in tariff = 6 cents Retail variable charge = 22 cents	
Solar PV system output (kWh)	6000 kWh	
	Exports to grid	*Imports from grid*
Net metering arrangement		
Change in metered volumes (kWh)	2000 kWh exported assuming export rate of one-third	4000 kWh avoided imports
Financial benefit ($)	$120 (2000 x 6/100)	$880 (4000 x 22/100)
Gross metering arrangement		
Under gross metering, all generated electricity is exported (kWh)	6000 kWh exported	No change in metered imports
Financial benefit ($)	$360 (6000 x 6/100)	$0

Under a net metering arrangement, assuming an export rate of one-third of the electricity generated, the household earns $120 through feed-in tariffs (2000 kWh exported at 6c/kWh converted to dollars). However, of the 6000 kWh generated, 4000 kWh is used for the household's own consumption purposes so that the household's demand for electricity from the grid is reduced by 4000 kWh. In 2015–16 under Tariff 11, households are charged roughly 22c/kWh, so the household obtains an additional and larger financial benefit of $880. Overall, under a net metering arrangement the household receives $1000 ($180 + $880), while under a gross metering arrangement the household only earns $360.

Financial return sensitivity tests

Sensitivity tests on the impact of feed-in tariffs

Chapter 4 includes an assessment of the impact on the financial returns to investment in a solar PV system in 2015–16 in solar zone 3, under a hypothetical scenario with and without feed-in tariffs. The results showed that, even without a feed-in tariff, under many circumstances the financial return to investment in solar is sufficient to break even within the useful life of the panels, given the presence of the SRES subsidy.

This section reproduces the lower bound, base case and upper bound tests from Chapter 4, but assumes that the investment occurs in solar zone 1, rather than solar zone 3. For a given rated system size, system output is expected to be higher in solar zone 1, with a solar rating of 1.622, versus 1.382 for solar zone 3.

The change in solar zones has a large effect on the estimated financial returns to investment. With no feed-in tariff, the only scenario that does not produce a payback period within the useful life of the system is for a 1.5 kW system under the lower bound scenario (Table 35). With a six per cent discount rate, for all other scenarios the payback period ranges from eight years to 18 years.

Table 35: Sensitivity tests: Impact on financial returns (investment in solar zone 1 in 2015–16)

System size (kW)	*Scenario 1: lower bound*			*Scenario 2: base case*			*Scenario 3: upper bound*		
	IRR (%)	*0% (yrs)*	*6% (yrs)*	*IRR (%)*	*0% (yrs)*	*6% (yrs)*	*IRR (%)*	*0% (yrs)*	*6% (yrs)*
Feed-in tariff = avoided cost									
1.5 kW	10.2%	9	12	11.5%	8	11	13.6%	7	10
3.0 kW	17.3%	6	7	19.4%	5	6	22.0%	5	6
5.0 kW	18.6%	6	7	21.1%	5	6	24.0%	5	5
Feed-in tariff = 0 cents									
1.5 kW	5.0%	12	nbe	11.0%	8	11	11.0%	8	12
3.0 kW	8.4%	10	14	12.2%	7	10	16.6%	6	8
5.0 kW	6.6%	11	18	11.0%	8	11	16.0%	6	8
Feed-in tariff = 0 cents and gross system prices increased by 10 per cent									
1.5 kW	3.1%	15	nbe	5.5%	12	nbe	7.7%	10	16
3.0 kW	5.9%	12	nbe	9.2%	9	13	12.4%	7	10
5.0 kW	4.2%	13	nbe	8.0%	10	15	11.8%	8	11

Note: 'nbe' is 'no break even'. Calculations based on a system installed in solar zone 1. Key assumptions underlying the calculations relate to gross and net installed system prices (system installation costs can vary significantly for systems with the same rated outputs), the output of the system in kWh (many factors can influence realised system output), projected wholesale energy prices (as wholesale prices drives the feed-in tariff under an avoided cost methodology, although market rates can differ), the variable component of projected retail tariffs, and the rate of export and the ability of households to shift consumption to generating hours. All three scenarios include network tariff re-balancing which reduces the financial returns to solar investment.

Source: QPC calculations.

Solar zone 1 includes smaller and inland population centres in Queensland as opposed to the major population centres along the eastern seaboard which are in solar zone 3. As average system prices might be higher, the tests were re-run assuming system prices are 10 per cent higher. Under the lower bound scenario, with a six per cent discount rate, none of the system sizes break even within the useful life of the panels. However, in most other scenarios, investment breaks even within 10 to 16 years of investment.

A household's average cost of consumption

The financial return to solar investment in the body of the report focuses on the internal rate of return and payback periods. Another measure sometimes used is the change in the average cost of consumption from solar investment, which is the difference between the average cost of consuming a kilowatt hour pre- and post-investment in solar.

For a 3.0 kW system with the feed-in tariff set based on the avoided costs of supply, and all other assumptions based on base case assumptions, the reduction in the average cost of consumption that a solar household obtains, ranges between 2.4 cents and 7.8 cents depending on the discount rate (Table 36).

If a subsidy is included in the feed-in tariff, such as when the feed-in tariff is set equal to the variable component of the retail tariff, it results in a larger reduction in the average cost of consumption. For a 3.0 kW system, the average cost of consumption is reduced by 4.2–9.8 cents.

Table 36: Average cost of consumption: Impact on financial returns (investment in solar zone 3 in 2015–16)

System size (kW)	*IRR (%)*	*Difference in average cost of consumption (c/kWh)*			
		Discount rate = 0%	*Discount rate = 3%*	*Discount rate = 6%*	*Discount rate = 9%*
FiT = avoided cost, base case assumptions					
1.5 kW	7.7%	–3.9	–2.4	–1.4	–0.7
3.0 kW	13.4%	–7.8	–5.3	–3.6	–2.4
5.0 kW	14.5%	–11.4	–7.9	–5.5	–3.9
FiT = variable component of retail tariff					
1.5 kW	11.3%	–4.7	–3.2	–2.1	–1.4
3.0 kW	20.9%	–9.8	–7.2	–5.4	–4.2
5.0 kW	25.4%	–15.3	–11.7	–9.2	–7.5

Note: 'IRR' signifies 'internal rate of return'. A dash (–) signifies a reduction in the average cost of consumption from solar investment. The post-investment calculation is a weighted average of the cost of own-generation and consumption combined with the cost of imports from the grid. All calculations hold all base case assumptions constant (e.g. electricity retail prices, consumption levels, export rates, gross solar PV system prices, tariff re-balancing) and purely vary the FiT. Calculations based on a system with a useful life of 20 years, installed in solar zone 3.

Source: QPC calculations.

Investment by small businesses

A household that installs a solar system at the principal place of residence will not pay taxes on revenues from the sale of STCs, but will not be able to claim a deduction from the depreciation of the system (assuming the private residence is not being used to generate tax assessable income). Households also cannot claim a deduction from any interest costs resulting from borrowings used to fund the installation of the solar system.

Where a small business invests in a solar PV system the investment is treated as a depreciable asset for the purposes of taxation, similar to any other form of investment undertaken for the purpose of generating business income (Table 37). GST is payable on the purchase of the system, but a GST credit can be claimed.

Interest cost on borrowings can be included as a deduction against taxable income. Income from the sale of STCs is treated as assessable income.

Where taxpayers install panels on properties used for private purposes, including the principal place of residence, any feed-in payments received will generally not constitute assessable income. This is because the size and scale of the system installed indicates that the system was installed to cater for the energy needs of the household (a non-income-producing purpose). However, if the size and scale of the system was far in excess of the needs of the household, and consequently the amount of the credits received was large and regular, this could result in the amounts transforming into ordinary income and therefore being assessable.[277]

Table 37: Tax implications of solar investment for small businesses

Tax	*Tax treatment*
Depreciation	The entire photovoltaic solar system is a depreciating asset, including photovoltaic cells, a roof mounting frame, various fixings, electrical wiring and conduits and inverter. Solar system assets are depreciable under the Capital Allowances provisions of the Tax Act. The ATO has ascribed 20 years as the effective life of solar panels, and therefore the assets are depreciable over this time period.
Accelerated depreciation	The Australian Government 2015–16 Budget announced businesses that with an annual turnover of under $2 million could claim immediate tax deductions on all purchases below $20,000 up until June 30, 2017; rather than those deductions needing to be spread over several years. A deduction is available where that asset is installed on a property wholly used to produce assessable income through rent or through the operation of a business. The cost for the purposes of this deduction would be the gross price of the unit. In other words, the cost for depreciation purposes would be the amount the taxpayer pays the installer to install the unit plus the rebate they have received (and included in assessable income). In the event that the panels cost more than $20,000, a business can claim 15% of the cost in the year they are installed, and 30% in subsequent years.
GST on solar system purchase	Whether a taxpayer makes taxable supplies such as those typically produced in a majority of businesses, or input taxed supplies such as rent from residential property, will largely drive the GST consequences of acquiring a solar unit. A business taxpayer who wholly makes taxable supplies from the use of premises is able to claim input tax credits associated with the purchase of a solar unit. However, where a taxpayer is making supplies of residential accommodation and receiving rent, they will typically not be able to claim GST credits.
Interest on borrowings deduction	Interest on loans taken to fund the purchase of solar panels used on premises that are used wholly to produce assessable income are deductible.
Income from STCs	Income from the creation and sale of STCs is included as assessable income.

Source: InterActive Tax Consultants 2014.

For small businesses, the revenue generated through feed-in tariffs is included as assessable income. If the investor is registered for GST purposes and makes the installation with the intention of furthering business enterprise, then GST will be applied to any income generated from the panels.

The general position is that taxpayers who install solar panels on a property which is used in a business or other income-producing activity are not in the business of generating electricity. Nonetheless, there is a direct link between the electricity generated by the panels and the electricity used in the income-producing activity. Therefore, any payments from the sale of electricity generated by the solar panels and fed back into the grid constitute assessable income and must be declared as such.

Investment in solar provides a healthy financial return to businesses given the subsidy provided by the Small-scale Technology Certificates (STCs), and assuming that the business is able to achieve a low rate of export,

[277] See http://www.taxreporter.com.au/articles/news/solar-panels, accessed 22 September 2015.

so that almost all of its generated electricity is used by the business (Table 38). If the small business is eligible for the accelerated depreciation incentive then the internal rates of return are significantly higher and the payback periods are halved from those shown below.

Table 38: Financial return to a small business investing in solar in 2015–16

	Solar zone 1		*Solar zone 2*		*Solar zone 3*	
	IRR (%)	*B/E (years)*	*IRR (%)*	*B/E (years)*	*IRR (%)*	*B/E (years)*
Without the accelerated deprecation incentive that applies to 2017						
3.0 kW system	26.0%	5	23.1%	6	18.6%	7
5.0 kW system	31.2%	4	27.6%	5	22.0%	6

Note: Key assumptions include: the feed-in tariff is based on the avoided costs of supply; STCs reduce system costs; and the rate of export is 10 per cent. As business opening hours may encompass daylight generating hours, some businesses may export less than 10 per cent. On the other hand, a business's system will also export electricity to the grid on days when the business is closed. Breakeven calculated using a discount rate of nine per cent.

Source: QPC calculations.

Emissions sensitivity tests

Cost of abatement and responsiveness of solar investment

A subsidy provided through a feed-in tariff induces a level of additional investment in solar, thereby reducing carbon emissions. This section tests the cost of abatement (see Chapter 5) assuming the responsiveness of solar investment is double compared to what is assumed in the modelling undertaken for this inquiry by ACIL Allen.

Cost of abatement estimates are provided for four subsidy or policy scenarios, which vary by the groups receiving the subsidised feed-in tariff:

- scenario 1—all existing and new systems;
- scenario 2—all existing solar PV systems (other than SBS systems), plus new systems under base case growth, plus additional systems resulting from the feed-in tariff subsidy;
- scenario 3—all ‘new’ systems. These systems include all new systems resulting from base case growth plus additional systems resulting from the feed-in tariff subsidy; and
- scenario 4—only ‘additional’ systems resulting from the feed-in tariff subsidy. These systems are additional to those under the base case growth scenario.

If the responsiveness of solar investment to an increase in subsidies is doubled, then the cost of abatement estimates are unchanged under scenario 4 where the subsidies only go to truly 'additional' systems resulting from the subsidy. Therefore, while the number of 'additional' systems doubles, and exports double (the denominator in the calculation), the subsidy equivalent also doubles (the numerator), so that the cost of abatement estimate is unchanged.

The decline in the cost of abatement estimates under subsidy scenarios 1–3 ranges between 39 and 44 per cent (calculated based on the change in the lower bound cost of abatement estimates) (Table 39).

Table 39: Investment responsiveness and the subsidy equivalent cost of abatement, \$/t CO_2 reduction

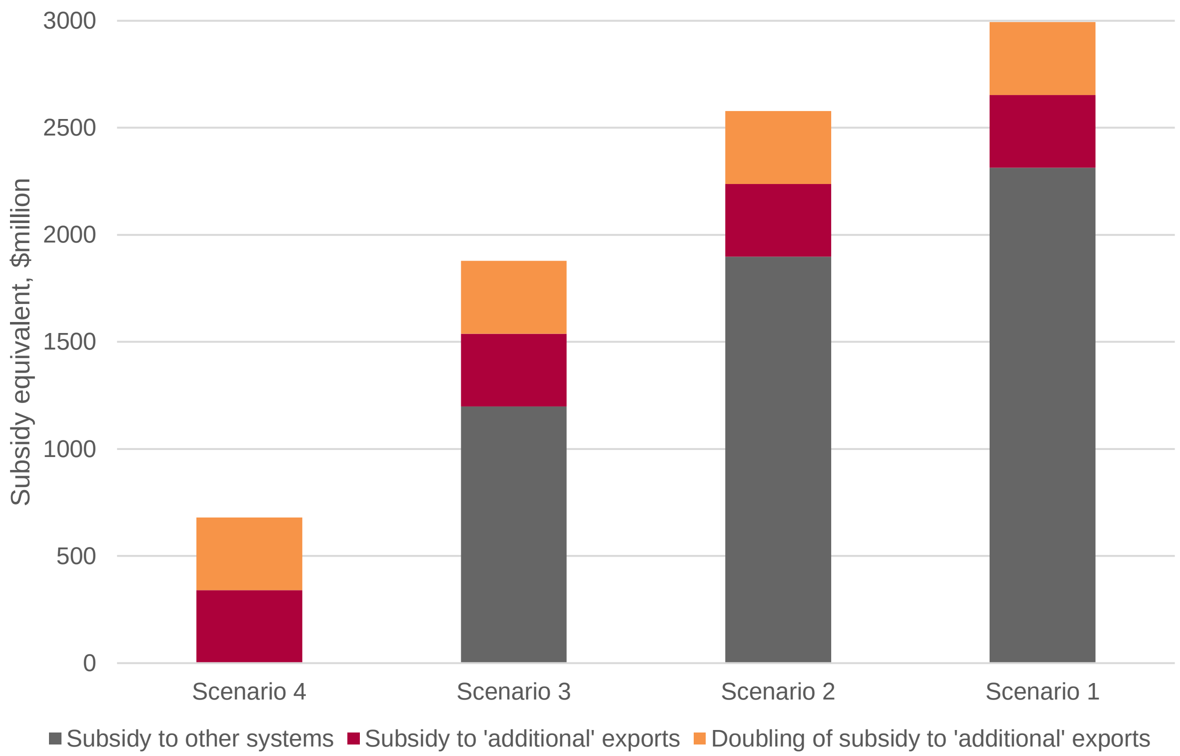
	Base case responsiveness		*A doubling of responsiveness*		*Lower bound % change*	
Policy-targeting scenario	*Black coal (\$/t CO_2)*	*Mix of thermal fuels (\$/t CO_2)*	*Black coal (\$/t CO_2)*	*Mix of thermal fuels (\$/t CO_2)*	*Black coal (%)*	*Mix of thermal fuels (%)*
1. Subsidy paid to exports from all existing and new systems	463–590	626–762	261–335	353–432	–44%	–44%
2. Subsidy paid to all exports, excluding exports from premium SBS systems	390–484	528–625	225–282	304–364	–42%	–42%
3. Subsidy paid to exports from all new systems	268–327	363–422	164–203	222–262	–39%	–39%
4. Subsidy paid to exports from 'additional' systems	59–80	80–103	59–80	80–103	0%	0%

Notes: The subsidy equivalent includes both the feed-in tariff subsidy plus the SRES subsidy. Data based on modelling of the impact of a feed-in tariff equal to the variable component of the retail tariff. Cost of abatement calculated as (\$ subsidy equivalent / tonnes of abatement). Under each subsidy scenario, a doubling of investment responsiveness doubles the volume of abatement (the denominator)). However, the increase in the subsidy equivalent varies by scenario and is doubled only under scenario 4. Export rate of 50 per cent assumed. Lower and upper bounds based on discount rates of 5 and 10 per cent. Discount rate for abatement (millions of tonnes of CO_2) calculated over period 2017–18 to 2054–55. Discount rate for subsidies calculated over period 2017–18 to 2034–35 which was the projection period used in ACIL Allen modelling for this inquiry. The additional time period for abatement reflects the capital nature of solar PV systems with an assumed useful life set at 20 years (consistent with most financial returns calculations undertaken in this report). The 'mix of thermal fuels' abatement scenario is based on ACIL Allen modelling of a potential Queensland Renewable Energy Target undertaken for the QPC's broader electricity inquiry. See ACIL Allen Consulting 2014, pp. 113–14 for the rationale for discounting the volume of abatement. ^ The cost estimates include the SRES subsidy equivalent at \$145–\$175 million.

Source: QPC calculations based on data from ACIL Allen Consulting, 2015.

In the case of scenarios 1–3, the cost of abatement estimates are lower because the doubling of abatement is accompanied by a smaller proportional increase in the subsidy equivalent estimates (illustrated in Figure 63). This occurs because the subsidy equivalent is only increased for that proportion of the subsidy equivalent 'base' related to 'additional' systems (which are doubled). A doubling of responsiveness does not increase the subsidy equivalent related to subsidies provided to existing systems, or systems under base case growth. Given that the proportion of subsidies going to truly additional exports is lowest under scenario 1, the percentage reduction in abatement cost under scenario 1 is highest (the numerator changes the least, while the denominator doubles).

Figure 63: Change in subsidy equivalent under a doubling of solar investment responsiveness



Source: QPC calculations.

Cost of abatement estimates from different feed-in tariff scenarios

The cost of abatement estimates provided in Chapter 5 were based on modelling of a feed-in tariff equal to the variable component of the retail tariff. As other feed-in tariff scenarios were also modelled, and as the responsiveness of investment may differ under different subsidies, cost of abatement estimates were constructed using the alternative feed-in tariff scenarios (Table 40).

Where the feed-in tariff is equal to 10 cents real, the additional solar generation is small at only 85 GWh by 2025–26. This is because the feed-in tariff paid under the base case is set to avoided costs, and as wholesale energy costs are projected to rise over time there is minimal difference, on average, between a feed-in tariff set equal to 10 cents real and a feed-in tariff set to avoided costs over time. The per unit subsidies under the '15 cents real' and 'avoided costs plus 10 cents real' scenarios are significantly greater leading to much stronger investment responses.

The cost of abatement estimates for the '10 cents real 'scenario are less than under the base case based on avoided costs. For example, where the subsidy policy pays all new systems (scenario 3), estimates are reduced from \$268–\$327 per tonne of CO_2 to \$116–\$181 per tonne of CO_2. The reason the estimates are lower is that the NPV calculations include years in which the buyback rate (based on avoided costs) is greater than 10 cents real (that is, there is a negative subsidy in some years). If the subsidies and generation volumes in those years are set to zero, then the cost of abatement estimates are much higher. For example, the estimates under policy scenario 3 become \$318–\$353, compared to \$116–\$181.

The estimates for the '15 cents real' and 'avoided costs plus 10 cents real' scenarios are comparable to the base case estimates across the four policy scenarios.

Table 40: Cost of abatement estimates under alternative FiT scenarios

Modelled FiT scenario	*Base case: FiT = avoided costs*	*FiT = 10 cents real*	*FiT = 15 cents real*	*FiT = avoided costs + 10 cents real*
Policy targeting scenario	*Black coal ($/t CO_2)*	*Black coal ($/t CO_2)*	*Black coal ($/t CO_2)*	*Black coal ($/t CO_2)*
1. Subsidy paid to exports from all existing and new systems	463–590	291–431	450–583	492–628
2. Subsidy paid to all exports, excluding exports from premium SBS systems	390–484	193–292	374–472	435–540
3. Subsidy paid to exports from all new systems	268–327	116–181	262–325	303–371
4. Subsidy paid to exports from ‘additional’ systems	59–80	45–60	49–68	65–85

Notes: The subsidy equivalent includes both the feed-in tariff subsidy plus the SRES subsidy. Lower and upper bound estimates based on 5 and 10 per cent discount rates, respectively; 50 per cent export rate assumed.

Source: QPC calculations based on data from ACIL Allen Consulting, 2015.

APPENDIX E: THE RENEWABLE ENERGY TARGET

Under the Renewable Energy Target (RET), renewable energy generators and owners of small-scale renewable energy systems (solar water heaters, heat pumps, and small-scale solar PV, wind, and hydro systems) create certificates for every megawatt hour of electricity they produce. Liable entities (generally electricity retailers) are legally required to purchase certificates and surrender them to the Clean Energy Regulator (CER) each year to demonstrate compliance with the RET. The creation of certificates and the legal obligation to buy them creates a market that provides financial incentives for the installation of both large-scale renewable generators and small-scale renewable energy systems.

The RET scheme

The Mandatory Renewable Energy Target (MRET) was introduced in 2001 to support emerging renewable energy generators. The objective of the MRET was to increase the share of renewable energy generation by two per cent above levels prevailing at that time, by 2010. The mechanism to accomplish the target was a tradeable certificate scheme — renewable generation created Renewable Energy Certificates (RECs), which liable entities then had to purchase and surrender.

In 2009, a Solar Credits multiplier — which multiplied the number of RECs a small-scale system was entitled to — was introduced to boost support for small-scale solar PV systems. The result of the multiplier and other changes was high growth:

> *Shortly after the expansion of the scheme there was a boom in the installation of small-scale renewable energy systems (mostly rooftop PV systems) driven by generous feed-in-tariff schemes introduced by state and territory governments, the Solar Credits multiplier under the RET and falling system costs. This resulted in a large surplus of Renewable Energy Certificates (RECs) in the market, causing REC prices to fall. This created uncertainty in the REC market for potential investors in large-scale renewable generation.*[278]

In response, the Australian Government amended the legislation to split the RET scheme into two parts:

- the Small-Scale Renewable Energy Scheme (SRES); and
- the Large-Scale Renewable Energy Target (LRET).

RECs were replaced with Large Generation Certificates (LGCs) and Small-scale Technology Certificates (STCs), which effectively separated the MRET into a large- and small-scale scheme.

Commencing in 2010, the RET was expanded to ensure at least 20 per cent of Australia’s electricity comes from renewable sources by 2020. The annual target for the LRET was to rise to 41,000 GWh in 2020, while the uncapped SRES was forecast to deliver at least 4000 GWh by 2020. Together these targets intended to deliver a peak of 45,000 GWh of renewable generation in 2020, and meet the 20 per cent renewable generation target.

Both the SRES and LRET schemes commenced on 1 January 2011. The SRES and LRET have separate and non-interchangeable certificate markets and obligations for liable entities. The Solar Credits multiplier scheme was terminated on 1 January 2013.

[278] Warburton et al. 2014, p. 2.

RET targets

RET legislation sets a volume target for renewable energy generation. In 2015, reforms reduced the LRET target to 33,000 GWh by 2020, with that level held to 2030 (Table 41). Unlike the LRET, the SRES does not have binding annual targets. The SRES is uncapped, allowing all eligible installations to receive assistance.

Achieving the large-scale target of 33,000 GWh by 2030 would result in roughly 23.5 per cent of Australia's electricity generation being from renewables (double the current levels). While the respecified target is lower than the 2010 target specified in gigawatt hours, it is still forecast to result in a higher proportion of energy being sourced from renewables compared to the targets in 2010 (23.5 per cent versus 20.0 per cent). A higher proportion of renewables is forecast because electricity demand has been much weaker than forecast in 2010.

Table 41: Required GWh of renewable source electricity

Year	*GWh*	*Year*	*GWh*
2001	300	2016	21,431
2002	1100	2017	26,031
2003	1800	2018	28,637
2004	2600	2019	31,244
2005	3400	2020	33,850
2006	4500	2021	33,000
2007	5600	2022	33,000
2008	6800	2023	33,000
2009	8100	2024	33,000
2010	12,500	2025	33,000
2011	10,400	2026	33,000
2012	16,763	2027	33,000
2013	19,088	2028	33,000
2014	16,950	2029	33,000
2015	18,850	2030	33,000

Source: Renewable Energy (Electricity) Act 2000, S40, pp. 91–92.

Liable entities

Liable entities have a legal obligation to buy and surrender LGCs and STCs to the CER on an annual basis. A large-scale renewable generator receives revenue both from energy sales to the wholesale market and from the sale of certificates.

Box 31: Liable entities

Large renewable generators and the owners of small-scale systems are eligible to create certificates for every megawatt hour of power they generate — creating the 'supply' side of the certificate market.

The purchase of certificates is a legal requirement for liable entities, in accordance with the *Renewable Energy (Electricity) Act 2000*.

Under the RET, liable entities are classified as an individual or company who is the first person to acquire electricity from the grid, which has an installed capacity of 100 MW or more. This is usually an electricity retailer, but liable entities also include manufacturers who purchase more than 100 MW from the grid.

To meet their obligation under the scheme, liable entities must purchase and surrender an amount of LGCs and STCs based on the volume of electricity they purchase each year. The amount of certificates liable entities are required to purchase is determined by the renewable power percentage and the small-scale technology percentage.

Source: Clean Energy Regulator, accessed at http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/Renewable-Energy-Target-liable-entities on 4 September 2015.

Renewable power percentage

The amount of large-scale generation certificates a liable entity is required to surrender each year is proportional to its liable electricity purchases. The required amount is determined by each year multiplying the renewable power percentage by a liable entity's electricity purchases minus any partial exemption certificates.

The 2015 renewable power percentage was set at 11.11 per cent. Given total energy consumption forecasts for 2015, this equates to 18.85 million large-scale generation certificates. If a liable entity does not meet its liability, it may be subject to a large-scale generation shortfall charge.

Small-scale technology percentage

The small-scale technology percentage regulates demand by determining the proportion of electricity RET liable entities are liable for, and how many STCs those entities are required to surrender each quarter. If a liable entity does not surrender enough certificates to meet its liability, it may be subject to a small-scale technology shortfall charge.

The 2015, the small-scale technology percentage is 11.71 per cent, which equates to 20.57 million STCs. The percentage is based on estimates of the number of STCs expected to be created in that year, adjusted for any surplus or deficit of certificates from the previous year.[279] The CER forecasts the number of small-scale generating units expected to be installed, taking into account the size of systems (rated output) and the regional distribution of installations by postal zones. The forecast determines the likely supply of STCs. Liable entities are then required to purchase enough certificates to meet the likely supply. The CER calculates the small-scale technology percentage applying to each liable entity, using electricity demand forecasts, on the basis that each certificate represents one megawatt hour. Given errors in forecasts and lags in the creation and submitting of certificates, the CER has a process of adjusting the small-scale technology percentage for any surplus or deficit from the previous year.

Implications of the uncapped SRES

As there is no binding target for the SRES, the cost of STCs to liable entities is uncapped. Whatever the supply of STCs, the small-scale technology percentage will be set at a level that matches demand for STCs to the available supply. Any changes that influence the number of new small-scale generating installations will result in changes in the volume of STCs supplied and, therefore, the legally required demand for STCs. The setting

[279] Warburton et al. 2014, p. 6.

of the small-scale technology percentage does not take any account of other factors such as trends in electricity demand or the relative generation costs of alternative technologies.

A state government policy that leads to higher installation rates will raise the supply of STCs with a matching increase in the legally required demand for STCs by liable entities. As a single small-scale technology percentage applies to all liable entities, changes in installation rates in one state or territory influences STC costs for liable entities in other states and territories.

How STCs are created

Installation of approved systems (Box 32) results in the creation of STCs. The number of STCs that can be created per system is based on the system's geographic location, year of installation, and the amount of electricity that is:

- expected to be generated by the solar, wind or hydro system over the course of its lifetime of up to a maximum of 15 years; or
- displaced by the solar water heater or heat pump over the course of its lifetime of up to 10 years.

One STC is equal to approximately one megawatt hour of eligible renewable electricity either generated or displaced by the system.

Box 32: SRES eligible systems

STCs can be created following the installation of an eligible system, and are calculated by the amount of electricity a system produces or displaces. To be eligible for STCs, small generation units (including solar PV, wind turbines, and hydro systems) must:

- be installed no more than 12 months prior to the creation of certificates, and have its panels and inverter listed on the Clean Energy Council (CEC) list of approved components;
- meet Australian and New Zealand standards;
- use a CEC accredited designer and installer and meet the CEC design and install guidelines;
- comply with all local, state, territory and federal requirements, including electrical safety; and
- be classified as small-scale, and be a:
  - solar panel system that has a capacity of no more than 100 kW, and a total annual electricity output less than 250 MWh;
  - wind system that has a capacity of no more than 10 kW, and a total annual electricity output of less than 25 MWh; or
  - hydro system that has a capacity of no more than 6.4 kW, and a total annual electricity output of less than 25 MWh.

If the small-generation unit is larger than the capacity limits listed above, it will be classified as a power station and must be accredited as a power station under the LRET. If accreditation is successful, the unit may be eligible for LGCs.

Source: Clean Energy Regulator, accessed at http://www.cleanenergyregulator.gov.au on 4 September 2015.

The amount of electricity a solar PV system can generate depends on:

- the rated power of the system;
- the orientation and tilt of the system;
- whether shadows are cast over the system;
- the number of daylight hours;

- the intensity of the sunlight;
- the number of full sun versus cloudy days;
- quality and efficiency of the unit's components (for example, how well the system deals with high temperatures); and
- the ratio of panel capacity to inverter capacity.

It is possible for owners of renewable energy systems to create and sell the STCs themselves, but in practice, system installers usually offer a discount on the price of an installation or a cash payment in return for the right to create and sell the STCs.

There are four postal zones for the creation of STCs — referred to as solar zone ratings — which account for differences in the output of a system operating in different areas of Australia (Table 42). The vast majority of Queensland's population resides in postal code zone 3.

Table 42: Solar zone ratings

	Zone 1	*Zone 2*	*Zone 3*	*Zone 4*
MWh per kW of capacity	1.622	1.536	1.382	1.185

The number of STCs created accounts for the solar zone rating and the rated system output in kW (Table 43), as well as the number of generating years. The right to create STCs may be assigned annually, in five-year periods or for the life of the system as determined by the Renewable Energy (Electricity) Regulations 2001. The maximum life of a solar PV system for the purpose of creating STCs — the deeming period — is 15 years.

Table 43: STCs by solar zone rating and system-rated output

City	*Postal code*	*Postal code zone*	*System rated output in kW*	*Solar zone rating*	*Number of STCs*
Alice Springs	0870	1	1.5	1.622	36
Birdsville	4482		3.0		72
Cooladdi	4479		5.0		121
Charleville	4470	2	1.5	1.536	34
Longreach	4730		3.0		69
Mount Isa	4825		5.0		115
Adelaide	5000	3	1.5	1.382	31
Brisbane	4000		3.0		62
Cairns	4870		5.0		103
Hervey Bay	4655				
Gold Coast	4217				
Goondiwindi	4390				
Perth	6000				
Port Douglas	4877				
Rockhampton	4700				
Stanthorpe	4380				
Sydney	2000				
Toowoomba	4350				
Townsville	4810				
Hobart	7000	4	1.5	1.185	26
Melbourne	3000		3.0		53
			5.0		88

Note: Assumed installation date of 9 September 2015 (deeming period = 15 years). Number of STCs is an approximate only.

Source: Clear Energy Regulator, Small generation unit STC calculator, accessed at https://www.rec-registry.gov.au/rec-registry/app/calculators/sgu-stc-calculator on 9 September 2015; and Clean Energy Regulations 2001, Schedule 5.

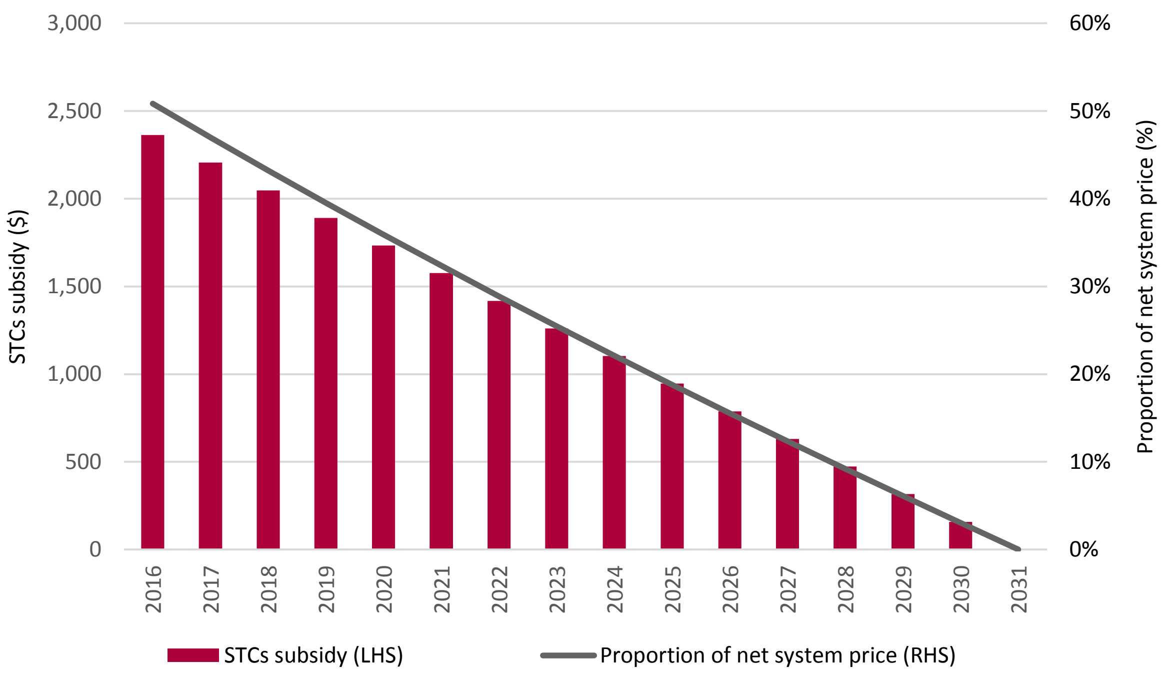
As an example, the number of certificates created by a 3.0 kW system in Brisbane in 2015 is 62 certificates (3.0 x 1.382 x 15 years).

The scheduled decline in the STC subsidy

The RET legislation includes a scheduled decline in the level of subsidy provided through STCs. The decline is implemented through successive decreases in the 'deeming period' used to calculate the number of STCs. For years prior to and including 2016, 15 years of generation are included in the creation of certificates, followed by 14 years for systems installed in 2017, 13 years for systems installed in 2018, and so on, until 2030, when only one year is eligible.

For a 2.0 kW system installed in postal zone 3 in 2016, the value of STCs is $2363, assuming a STC value of $38 per certificate. The level of subsidy in 2020 and 2025 declines to $1733 and $945, respectively (Figure 64). Expressed as a percentage of net system prices (excluding taxes), the subsidy still remains substantial in those years at 36 per cent and 19 per cent respectively.

Figure 64: Scheduled decline in the STC subsidy for a 3.0 kW system in postal zone 3



Source: QPC calculations.

The policy rationale for providing a STC subsidy is that it leads to a higher rate of investment in solar than would otherwise be the case in order to achieve the objective of CO2 emissions reduction. At the time of the design of the scheme, the relative inefficiency of solar (the high cost of systems compared to the energy generated) was considered likely to decline over time as the industry developed and the price of solar PV systems fell, so that a progressively lower subsidy would still sustain a solid level of new investment in solar. Actual system prices have declined strongly and are projected to continue to decline into the future.

The STCs subsidy helps 'internalise' potential external environmental benefits in the investment calculations of households. However, with increasing solar penetration rates, the extent to which there is investment in solar below some (unknown) socially optimal level progressively declines, justifying a decreasing level of subsidy.

Who captures the STC subsidy?

Demand for solar PV systems is generally regarded as being less responsive to changes in price (that is, it is relatively inelastic). This has implications for the proportion of STC subsidies passed through to households and businesses purchasing systems versus the proportion of subsidies able to be captured by industry suppliers. If suppliers capture a large proportion of the subsidies, then solar owners may not be fully compensated for any environmental benefits of their solar PV systems.

The responsiveness of supply and demand to a price change determines the economic incidence of a subsidy, such as the STC subsidy. The economic incidence of a subsidy is concerned with who benefits from the subsidy: is the subsidy passed through to consumers or is it largely captured by suppliers? In practice, both consumers and suppliers capture some of the subsidy, with consumers capturing a larger percentage the more inelastic their demand is. When demand is highly inelastic, the consumer gains most of the benefit from the subsidy, since almost the whole subsidy is passed on to the consumer through a lower price.

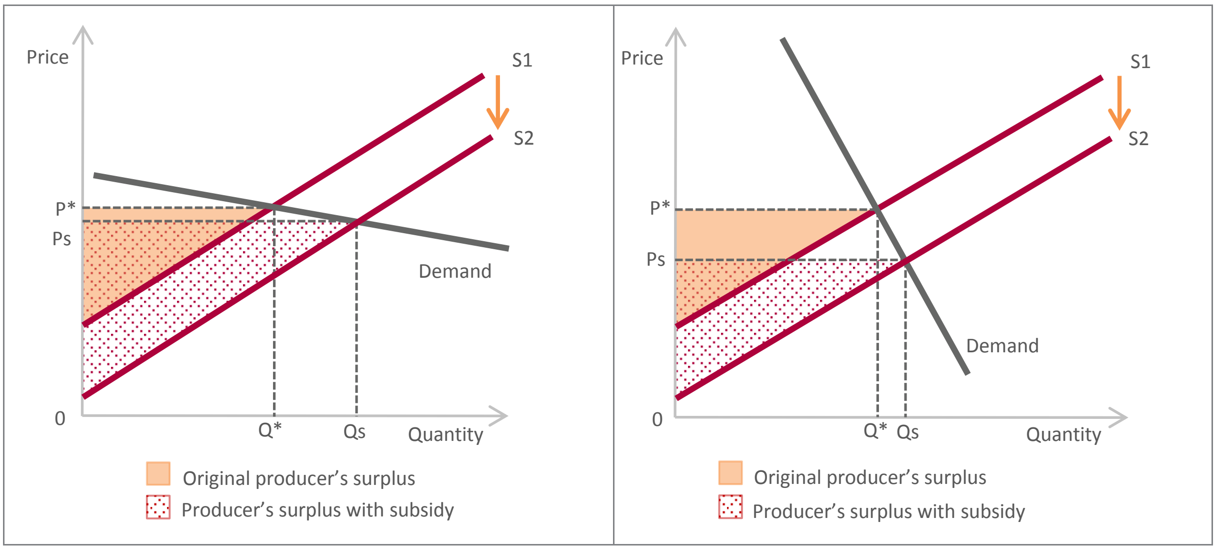
Figure 65 provides a stylised illustration of supply and demand for solar PV systems. A subsidy alters the initial equilibrium price (P*) and quantity demand (Q*) to a new equilibrium point represented by the intersection of (Ps, Qs) with the supply curve shifting outward from S1 to S2.

In the left-hand panel, demand is highly elastic (the demand curve is more horizontal). For a given subsidy and change in the price level there is a significant change in the quantity of panels demanded by consumers. The producer's surplus increases substantially, as producers are able to capture a significant proportion of the benefits of the subsidy.

In the right-hand panel, demand is inelastic, so that the same subsidy results in a larger change in price and a much smaller change in quantity demanded. With inelastic demand, the subsidy is passed through to consumers with only a small net increase in producer's surplus.

Changes in consumer surplus (the triangular areas below the demand curve and above the horizontal line established by the price level), are far greater with inelastic demand than with elastic demand, indicating that consumers capture more of the benefit of the subsidy when demand is inelastic.

Figure 65: The economic incidence of STC subsidies



Notes: The producer's surplus is the area above the supply curve and below the horizontal line established by the equilibrium price. For each supplied unit bounded with the equilibrium quantity, suppliers would have been willing to supply at a price represented by the supply curve, but receive the higher equilibrium price. A consumer's surplus results because, for quantities below the equilibrium quantity demanded, consumers would have been willing to pay more for a unit of the product (represented by points along the demand curve), but were able to purchase at the market equilibrium and lower price.

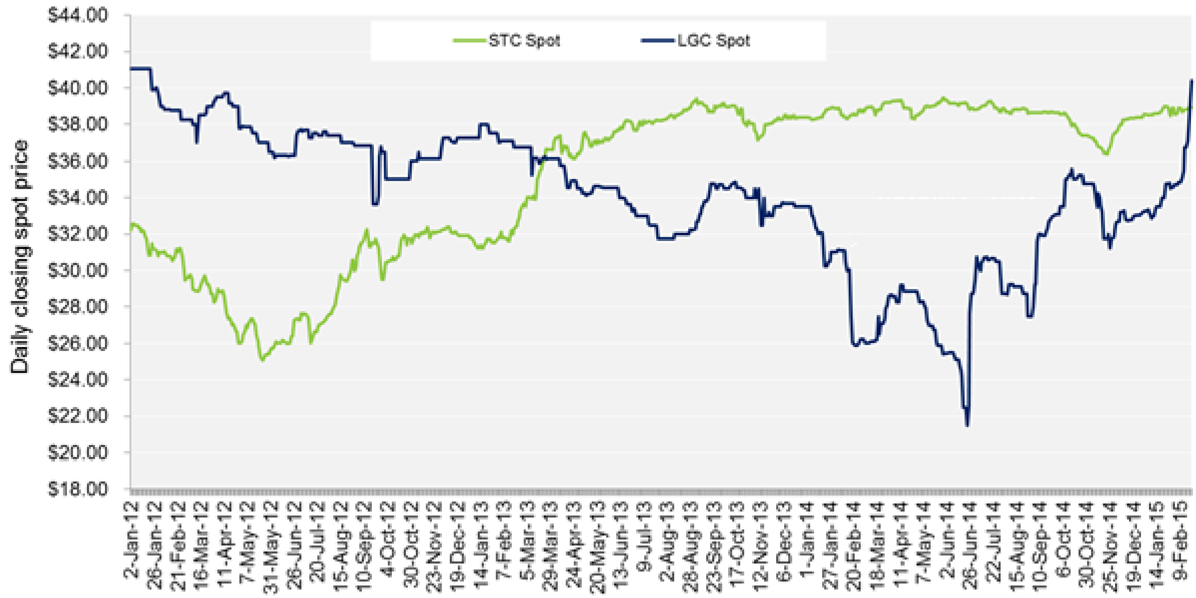
Little empirical research is available on the pass-through of the SRES. However, international studies tend to support high pass-through rates:

> *Henwood (2014) finds a low pass-through rate, while Dong et al. (2014) find nearly complete pass-through. These working papers use similar data, but very different empirical strategies ... We find a highly statistically significant coefficient on the rebate level of 0.16, implying a pass-through rate of 84 percent. In other words, a $1/W [watt] decrease in installer costs translates into an 84 cents/W decrease in the PV system price.*[280]

The price of certificates

Data from Green Energy Markets indicates that the spot price for LGCs in 2015 has ranged from a low of roughly $35 to just under $60 (as at 21 August 2015).[281] LGC spot prices trended steadily downwards from the beginning of 2012 until mid-2014. Since then, prices have risen to their current levels. In 2015, STC spot prices have remained just under, but close to, the reserve price of $40. This pricing behaviour has generally applied through the period since mid-2013.

Figure 66: LGC and STC spot prices



Source: Adapted from Green Energy Markets, accessed at <http://greenmarkets.com.au/resources/> on 4 September 2015.

[280] Gillingham 2015.

[281] See Green Energy Markets, accessed at <http://greenmarkets.com.au/resources/> on 4 September 2015.

APPENDIX F: REGULATION AND MONITORING OF LOCAL POLLUTANTS

This appendix describes key parts of the existing regulatory framework to address local pollutants and summarises Queensland monitoring outcomes.

Monitoring ambient air quality and pollutants

National Environment Protection (Ambient Air Quality) Measure

A National Environment Protection Measure (NEPM) is legislation designed to protect and manage particular aspects of the environment.

In 1998, the National Environment Protection Council made the *National Environment Protection (Ambient Air Quality) Measure* (the 'AAQ NEPM'), which set ambient air quality standards to apply in all states and territories. The AAQ NEPM provided a nationally consistent framework for the monitoring and reporting of a range of pollutants.

The AAQ NEPM requires all jurisdictions to submit an annual report on their compliance with the measure, including compliance with air quality standard targets set for the pollutants:

- carbon monoxide (CO);
- nitrogen dioxide (NOx);
- petrochemical oxidants (as ozone);
- sulfur dioxide (SO_2);
- lead (Pb);
- $PM_{2.5}$; and
- PM_{10}. [282]

Targets are set on the basis of evidence on the risks of health impacts to exposure.[283] A 2011 review of the AAQ NEPM found:

> *[I]n general, air quality in Australian cities is good by international standards. The data show that nitrogen dioxide, carbon monoxide, sulfur dioxide and lead concentrations are consistently below the AAQ NEPM standards in all jurisdictions. Most jurisdictions experience exceedances of the standards for particles (both PM_{10} and $PM_{2.5}$) and ozone on occasion. These exceedances often appear to be associated with bushfires and/or management burns.* [284]

The review examined the evidence on health impacts, with air quality targets subsequently lowered (i.e. made more stringent). The standards were set on the basis of scientific studies of air quality and human health. Australian conditions were taken into account in estimating the likely exposure of Australians to the major air pollutants. Each air quality standard has two elements: the maximum acceptable concentration; and the time period over which the concentration is averaged.

[282] The required content of the reports is detailed in the National Environment Protection (Ambient Air Quality) Measure, Technical Paper No. 8, Annual Reports (AAQ NEPM Technical Paper No. 8).
[283] NEPC 2011, Methodology for setting air quality standards in Australia: Part A, February.
[284] NEPC 2011, pp. 14–20.

National Pollution Inventory (NPI) Scheme

The NPI National Environment Protection Measure (NPI NEPM) provides the framework for the National Pollution Inventory (NPI) Scheme, which is an internet database designed to provide publicly available information on the types, and amounts of certain substances, being emitted to the air, land, and water.

Each participating jurisdiction is responsible for implementing the NPI NEPM. State and territory environment protection agencies have their own legislative frameworks to ensure there is compliance with the NEPM.

The NPI has broader coverage than the AAQ NEPM, containing data on 93 substances that are emitted to the environment. The substances included in the NPI have been identified as important because of their possible health and environmental effects. Greenhouse gas and energy reporting requirements are covered separately under the *National Greenhouse and Energy Reporting Act 2007*.

All Australian industrial facilities which meet the reporting criteria are required to submit annual reports of their emissions and transfers of NPI substances in waste. Queensland coal and gas-fired electricity generators are subject to NPI requirements as well as state regulatory requirements (Box 33).

Box 33: Queensland Environmental Approvals

Coal and gas-fired power stations are Environmentally Relevant Activities under the *Environmental Protection Act 1994* and Schedule 2 of the *Environmental Protection Regulation 2008*.

To prevent or minimise environmental harm, a person carrying out an activity must take all reasonable and practicable steps to ensure that best practices in environmental management are used.

The *Environmental Protection (Air) Policy 2008* establishes long-term objectives for sulfur dioxide, nitrogen dioxide, ozone, carbon monoxide, particles, lead and a number of air toxics.

Decisions regarding conditions of approval for ERAs must consider these objectives.

The stations require an Environmental Authority to operate. The Environmental Authority specifies monitoring and reporting requirements, including the contaminants to be monitored, indicators and frequency of monitoring requirements.

Each Environmental Authority sets maximum release limits to air for specified contaminants and may also specify minimum release heights, velocity and temperature limits. Contaminants not listed are not authorised for release. .

As each power station has obligations to report under the NPI, the site’s Environmental Authority requirements are designed to be consistent with NPI reporting requirements.

To ensure that operators comply with their Environmental Approval, and do not cause unlawful environmental harm, the *Environmental Protection Act 1994* provides a range of tools to help an administering authority enforce environmental obligations. These include:

- environmental protection orders;
- environmental evaluations;
- transitional environmental programs; and
- penalty infringement notices.

Source: DEHP 2016, Common conditions — prescribed environmentally relevant activities, Brisbane; DEHP 2015, Guideline — Environmentally Relevant Activities Compliance and Enforcement, Brisbane.

Each year all jurisdictions must report to the National Environment Protection Council on their progress in implementing the NPI NEPM.

In Queensland, the NPI NEPM is implemented under the *Environmental Protection Regulation 2008* (EP Regulation). Chapter 6 of the EP Regulation provides for penalties of up to $2000 for non-compliance with a reporting requirement and/or naming of the non-compliant party in the NEPC annual report. The State Penalties Enforcement Regulation 2000 also allows for Penalty Infringement Notices (on-the-spot-fines) of up to $200 to be issued under the EP Regulation.

Key Queensland 2014 ambient air quality outcomes

Air concentrations within the limits of exceedance standards does not mean that there are zero environmental and health impacts from emissions. The desired environmental outcome of the AAQ NEPM is ambient air quality that allows for the adequate protection of human health and well-being, implicitly recognising the benefits of activities that are a source of emissions, as well as the costs of lowering emissions.

The electricity supply industry is a source of emissions of the following substances:

- particulate material (PM_{10});
- sulfur dioxide (SO_2);
- nitrogen oxides (NOx);
- arsenic (As);
- carbon monoxide (CO);
- lead (Pb);
- nickel (Ni);
- mercury (Hg); and
- polycyclic aromatic hydrocarbons.[285]

PM_{10}, SO_2 and NOx are the main power station emissions substances which are of potential concern.[286] They can be associated with reduced lung function, chronic bronchitis, and other respiratory problems, such as asthma.

Monitoring indicates that there were very few breeches of ambient air quality standards in Queensland between January and December 2014. In general, the main factors influencing air pollution in SEQ include increasing population and the high number of motor vehicles, while in the other centres industrial activity is the major cause. Key findings from the 2014 report are highlighted in Box 34.

[285] National Pollutant Inventory fact sheets. Accessed at http://www.npi.gov.au/substances/fact-sheets.

[286] Australian Academy of Technological Sciences and Engineering (ATSE) 2009, The hidden costs of electricity: externalities of power generation in Australia, March, p. 37.

Box 34: Queensland ambient air quality reporting outcomes 2014

Ambient air quality monitoring at AAQ NEPM sites in Queensland between January and December 2014 showed no exceedances of the AAQ NEPM air quality standards for carbon monoxide, nitrogen dioxide, ozone and lead at any monitoring location. Exceedances of the AAQ NEPM standards occurred for:

- one-hour average sulfur dioxide at the Menzies and The Gap monitoring sites in Mount Isa due to industrial emissions;
- 24-hour average sulfur dioxide emissions at the Menzies monitoring site in Mount Isa due to industrial emissions;
- 24-hour average PM10 (particles less than 10 micrometres in diameter) at the Mountain Creek monitoring site in South East Queensland due to smoke from a bushfire, and at The Gap site in Mount Isa due to windblown dust; and
- 24-hour average PM2.5 (particles less than 2.5 micrometres in diameter) advisory reporting standard at the South Gladstone monitoring site due to bushfire smoke.

The AAQ NEPM goals were met in all regions with the exception of:

- one-hour average sulfur dioxide at the Menzies and The Gap sites in Mount Isa due to industrial emissions.

Compliance with the AAQ NEPM standards and goals could not be demonstrated for sulfur dioxide at the Stuart monitoring site in Townsville and for lead at The Gap monitoring site in Mount Isa because data availability was below the level required to make a valid assessment due to instrument failure.

Source: Department of Science, Information Technology and Innovation 2015, Queensland air monitoring report 2014, National Environment Protection (Ambient Air Quality) Measure, Brisbane, June.

A number of sulfur dioxide and PM_{10} exceedances were recorded:

> *In 2014, sulfur dioxide concentrations exceeded AAQ NEPM standards in Mount Isa and PM_{10} concentrations exceeded AAQ NEPM standards in Mount Isa and South East Queensland. $PM_{2.5}$ concentrations exceeded AAQ NEPM advisory reporting standards in Gladstone. There were no exceedances of the AAQ NEPM standards for carbon monoxide, nitrogen dioxide, ozone and lead.*[287]

The Mount Isa sulfur dioxide exceedances were due to emissions from industry. The PM_{10} exceedance in SEQ was due to smoke from a large bushfire on Stradbroke Island, and windblown dust in Mount Isa.

Additional detail on monitoring results for sulfur dioxide, nitrogen dioxide and PM_{10} is provided in Table 44.

[287] Department of Science, Information Technology and Innovation 2015, Queensland air monitoring report 2014, National Environment Protection (Ambient Air Quality) Measure, Brisbane, June, p. 16.

Table 44: Queensland monitoring outcomes for key substances

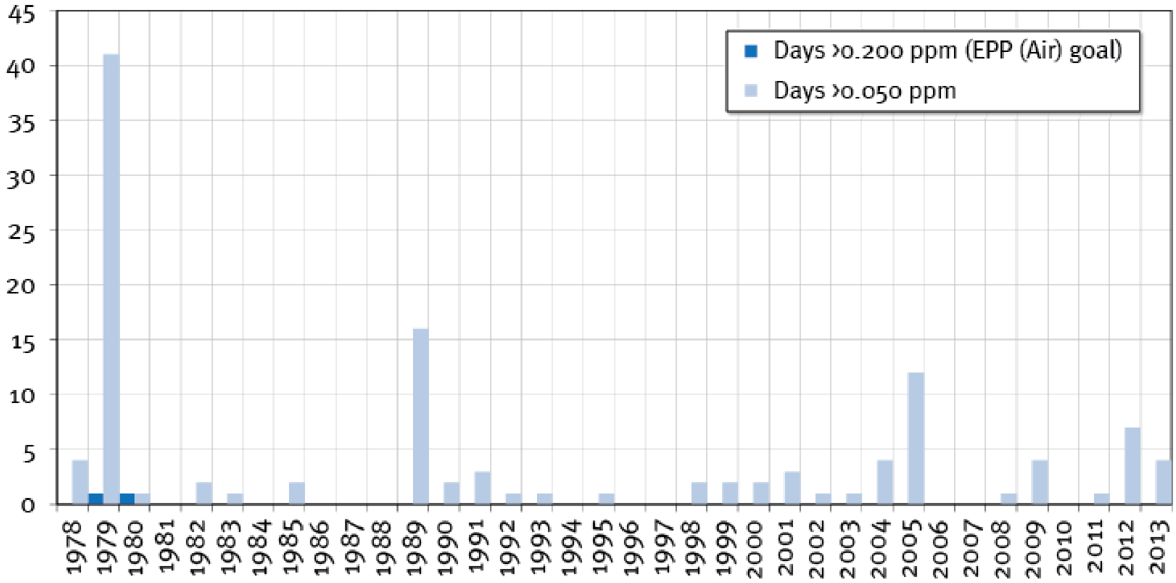
Substance	*Potential impacts*	*Queensland monitoring outcomes*
Sulfur dioxide: SO_2 is a colourless gas with a sharp, irritating odour	When sulfur dioxide combines with water and air, it forms sulfuric acid, which is the main component of acid rain. Sulfur dioxide affects the respiratory system, particularly lung function, and can irritate the eyes.	Monitoring indicates that emissions of sulfur dioxide are low unless significant industrial point sources of sulfur dioxide are present (e.g. coal-fired power stations or metals smelting). Peak sulfur dioxide concentrations in the Brisbane sub-region in South East Queensland are below 40 per cent of the AAQ NEPM standard. In Queensland, there is less heavy industry than in Europe or North America, where the potential for forming acid rain from sulfur dioxide emissions is higher. Queensland weather conditions and low sulfur content of fuels reduce the potential for acid rain. Significant concentrations of sulfur dioxide are only measured in Queensland near large industrial sources.
Nitrogen dioxide: NOx has an odour, and is an acidic and highly corrosive gas	Elevated levels of nitrogen dioxide can cause damage to the human respiratory tract and increase a person's vulnerability to, and the severity of, respiratory infections and asthma. Long-term exposure to high levels of nitrogen dioxide can cause chronic lung disease. High levels of nitrogen dioxide are also harmful to vegetation—damaging foliage, decreasing growth or reducing crop yields.	Monitoring indicates concentrations well below standards. Typical outdoor nitrogen dioxide levels are well below the 1-hour standard and exposure at these levels does not generally increase respiratory symptoms.
Particulate matter: PM_{10} is particulate matter 10 micrometres or less in diameter	Particles smaller than 10µm can enter the human respiratory system and penetrate deeply into the lungs, causing adverse health effects.	Monitoring indicates that performance against standards were met in SEQ, Gladstone, Mackay, and Townsville. The standard was not met in Mount Isa. Monitoring has not yet been carried out for Bundaberg, Cairns, Maryborough/Hervey Bay, and Rockhampton.

Source: Queensland Government, accessed at http://www.qld.gov.au/environment/pollution/monitoring/air-monitoring/air-quality-index/; and Department of Science, Information Technology and Innovation 2015, Queensland air monitoring report 2014, National Environment Protection (Ambient Air Quality) Measure, Brisbane, June.

Queensland ambient air quality trends

Levels of sulfur dioxide in SEQ are low due to the small number of emission sources in the region. The maximum number of exceedances in any one year appears to have declined over time (Figure 67).

Figure 67: Sulfur dioxide exceedances, 1978–2013

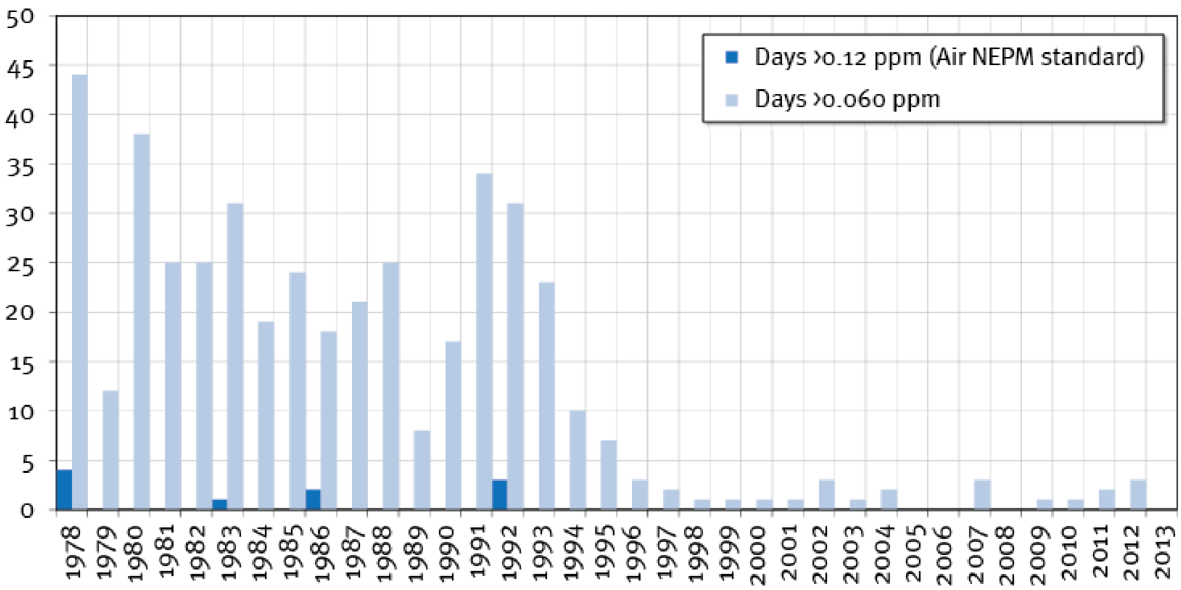


Note: Number of days per year the 1-hour average sulfur dioxide concentration exceeded the specified level.

Source: Queensland Government, Air Quality Trend Graphs, accessed at http://www.qld.gov.au/environment/pollution/monitoring/air-monitoring/trend-graphs/#.

Exceedances for nitrogen dioxide levels in recent years have been well below the *Queensland Environmental Protection Policy (Air)* goal for the protection of human health, and have declined sharply since 1978 (Figure 68).

Figure 68: Nitrogen dioxide exceedances, 1978–2013

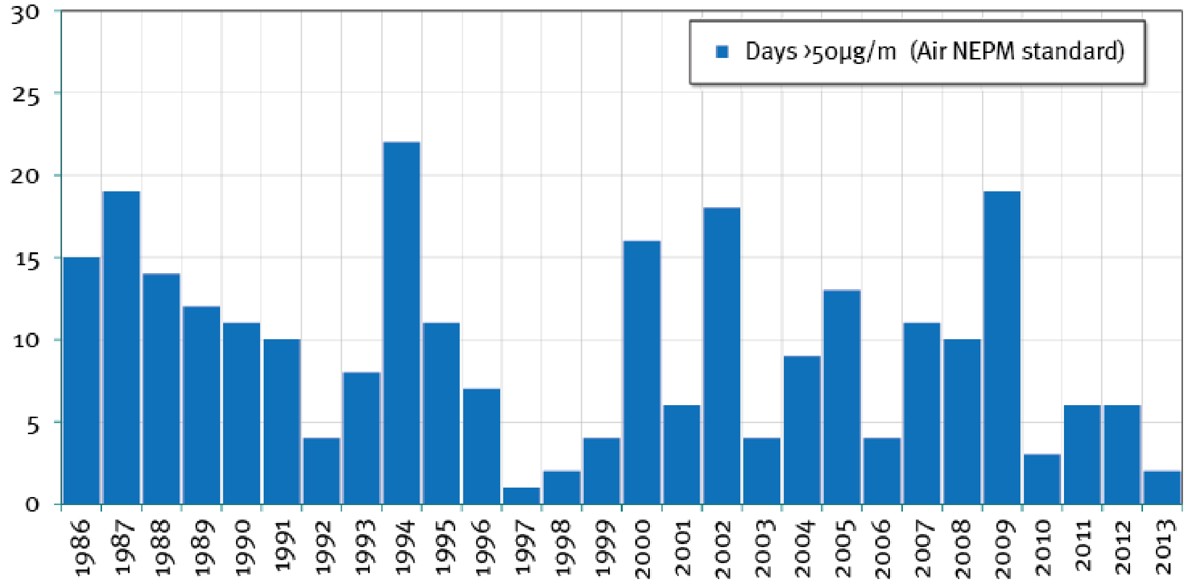


Note: Number of days per year the 1-hour average nitrogen dioxide concentration exceeded the specified level.

Source: Queensland Government, Air Quality Trend Graphs, accessed at http://www.qld.gov.au/environment/pollution/monitoring/air-monitoring/trend-graphs/#.

Despite population growth and growth in economic activity PM_{10} concentration exceedances remain stable to declining (Figure 69).

Figure 69: PM_{10} exceedances, 1986–2013



Note: Number of days per year the 24-hour average PM10 concentration exceeded the specified level.

Source: Queensland Government, Air Quality Trend Graphs, accessed at http://www.qld.gov.au/environment/pollution/monitoring/air-monitoring/trend-graphs/#.

APPENDIX G: SOLAR PV AND NETWORK IMPACTS

Identifying and measuring the impact of solar PV on distribution networks is challenging because of the range of impacts that solar PV has on networks, various factors that condition the impacts of solar PV, and data constraints. To investigate the impacts of solar PV on networks, this appendix:

- outlines the network planning process used by DNSPs to identify network constraints;
- discusses how solar PV is incorporated in those processes;
- lists existing and forecast constraints on DNSP's networks;
- analyses the relationship of solar PV to those constraints; and
- discusses capital and operating expenditure impacts related to solar PV.

DNSP network planning processes

Planning processes

Energex and Ergon Energy undertake a planning process each year to identify emerging network limitations (constraints). The identified constraints are included in each entity's published Distribution Annual Planning Report (DAPR).

The typical planning process involves the following major steps:

- validate load forecasts;
- evaluate the capability of the existing system;
- identify network risks/limitations in the system;
- formulate network options to address the risks/limitations and identify any feasible non-network solutions from prospective proponents;
- compare options on the basis of technical and economic considerations;
- select referred development option;
- undertake public consultation for the projects, and carry out detailed evaluation upon receipt of any alternative solutions from proponents; and
- initiate action to implement the preferred option through formal project approvals.[288]

Types of constraints

Energex identifies different types of network constraints: adequacy and security constraints; voltage-related constraints; and fault level constraints.

Reliability of supply is the probability of a system adequately performing under operating conditions. Reliability is dependent on two measures used in network planning:

[288] Energex 2015b, p. 77.

- 'Adequacy' is the capacity of the network to supply the electricity demand within acceptable quality of supply limits. It includes requirements that network elements operate within their ratings while maintaining voltage within statutory limits.
- 'Security' is the ability of the network to cope with faults on major plant and equipment without the uncontrolled loss of load. A secure network often factors in redundancy of major plant and equipment to tolerate the loss of single elements of the system. [289]

Network planning processes also identify fault- and voltage-related constraints. A fault constraint refers to defects in equipment resulting in an abnormal electrical current. DNSPs are required to manage the voltage on their network within a set tolerance range. A voltage constraint refers to situations where these requirements are not being met.

Other considerations include power quality impacts such as voltage fluctuations (flicker), phase unbalance and harmonic distortion. Solar can contribute to these impacts and result in interference to the supply of energy to other customers. These asset constraints may be mitigated by technical requirements imposed through the DNSP connection standards.[290]

Each of the different types of constraints can lead to a network asset being identified as a constrained asset. However, only a portion of identified network constraints will be related to adequacy or capacity constraints. Solar PV may have positive impacts on capacity constraints where it delays a constraint, and may have negative impacts by increasing the occurrence of fault- and voltage-related issues.

Customer Outcome Standard

Energex plans network investment to meet its Customer Outcome Standard. The security standard takes into account the following key factors:

- Feeders and substations are assigned a category according to criteria or the area (CBD, urban, rural), and the appropriate safety net is assigned to associated network elements.
- Plant and power line ratings depend upon their ability to discharge heat and are therefore appreciably affected by the weather, including ambient temperature and in the case of overhead lines, wind speed.
- A range of actions to defer or avoid investments such as non-network solutions, automated, remote and manual load transfer schemes and the deployment of a mobile substation and/or mobile generation increase utilisation of network assets.
- The value of customer reliability to optimise the timing of investments.
- The specific security requirements of large customer connections that are stipulated under the relevant connection agreements.[291]

The application of the Customer Outcome Standard ensures that under system normal conditions the normal cyclic capacity of any network component must be greater than the forecast load (10 PoE) (see Box 35 for a description of terminology and measures used in network planning).

The capacity of the network is also assessed based on the failure of network components (transformers or power lines) and a 50 PoE forecast load. This enables the load at risk under system normal (LARn) and the load at risk for contingency conditions (LARc) to be assessed as key inputs to investment planning against customer safety net targets.

[289] Energex 2015c.
[290] Energex return to the QPC information request.
[291] Energex 2015c, pp. 65–66.

Where these assessments indicate that the network is not able to meet the required safety net, the resulting network limitation must be addressed to ensure customer service obligations are achieved.

Box 35: Terminology and measures used in network planning

Probability of Exceedance

Probability of Exceedance (PoE) demand is a generalised approach to defining the probability of a forecast demand being exceeded:

- 10 PoE: the peak load forecast with 10% probability of being exceeded (every 1 in 10 years will be exceeded). Based on normal expected growth rates & weather corrected starting loads; and
- 50 PoE: the peak load forecast with 50% probability of being exceeded (every 1 in 2 years will be exceeded). Based on normal expected growth rates and weather corrected starting loads.

Load at risk

Load at risk is calculated using the forecast loads, the planned substation capacity, and the capacity of the network to allow the transfer of load away from the substation to other sources of supply based on the substation security standard criteria.

The load at risk is evaluated for both normal (LARn) and contingent (LARc) conditions. Under normal conditions, the loadings on a substation are not to exceed the normal cyclic capacity (NCC) of a major network component such as a zone substation transformer. Under contingent conditions, the loadings of a substation are not to exceed the available emergency supply under contingency whilst taking into consideration the security of supply standards of the substation.

Load at risk is the shortfall between the forecast load (either 10 PoE or 50 PoE) and the available supply. The general equations for LAR are as follows:

- LARn = 10 PoE – NCC where NCC is the normal cyclic capacity
- LARc = 50 PoE – available capacity – available supply (within security standard timeframe)

Network security standards are not being met if LARn or LARc is greater than 0.

Target Maximum Utilisation

Distribution feeder analysis is performed to assess feeder loads relative to NCC to establish feeder utilisation. The Target Maximum Utilisation (TMU) of each feeder takes into account the ability of generally transferring loads from four feeders into three feeders with some use of mobile generation to restore all loads in the event of a fault on the network. This is to allow for operational flexibility and load transfers to restore load during a contingency event. The TMU will vary for feeders that are a dedicated customer supply or CBD meshed or radial networks.

Maximum demand forecasts

Energex and Ergon Energy forecast summer and winter maximum demands for the system as a whole and for individual network assets.

System maximum demand forecasts

Energex system maximum demand forecasts are developed and reviewed twice each year following analysis of demand from the previous summer period and the most recent winter. Separate scenarios are developed that model factors such as the impact of demand side management initiatives, emission reduction strategies, energy efficiency initiatives, and penetration of embedded generation on the distribution network. The likelihood of scenarios is assessed with the most likely set of scenarios used for the system maximum demand forecasts.[292]

The purpose of system maximum demand forecasts is to validate sub-transmission and distribution network bottom-up forecasts. This seeks to ensure that bottom-up maximum demand forecasts reconcile to the system maximum demand forecasts.

System maximum demand forecasts are constructed by econometrically estimating the historical relationship between season daily maximum demand for the network as a whole and a number of economic

[292] Energex 2014.

and environmental variables that determine maximum demand (Box 36). Equations are estimated based on time series of daily data.

Once historical relationships are estimated, forecasts of network load are produced based on forecasts of the explanatory variables, such as forecasts for economic and population growth. Other information is also drawn upon in producing these forecasts, such as forecasts of solar PV take-up and installed inverter capacity, electric vehicle, air conditioning and battery uptake rates, and changes in appliance efficiency.

Block loads, solar PV and demand management are taken into account in modelling, but the specific ways in which the factors are incorporated within models is part of a process of ongoing model development.

Box 36: System maximum demand forecasts

For its system maximum demand forecasts, Ergon Energy estimates the following type of equation:

$Load = c + \beta 1 \times GSP + \beta 2 \times Max\ temp \times Aircon + \beta 2 \times Min\ temp \times Aircon + \varepsilon$, where:

c is a constant term, $\beta 1$ and $\beta 2$ are coefficients to be estimated, *GSP* is Gross State Product, and ε is the model's error term.[293]

Network load is the dependent variable. The historical data used in the regressions is based on observed loads and, therefore, includes the impact of embedded and distributed generation, as energy generated by customers and consumed on premises reduces network load (and energy sales).

Key model explanatory variables include:

- Economic and population growth is an important driver of maximum demand and is captured by the inclusion of the GSP term;
- Temperature related variation in daily maximum demand forecasts is captured by the inclusion of the daily maximum and minimum temperatures. Weather time series are derived from Bureau of Meteorology (BOM) data; and
- Increases in temperature sensitivity is incorporated in the model through the inclusion of the number of domestic air conditioning systems which is a key driver of load sensitivity changes.

Any variation in the daily peaks not captured by GSP and temperature is soaked up by the error term.

Model specification can vary depending on what data is included in the regression model, for example –weekends and public holidays if included, can tend to have lower peak demands associated with them. The effect of the lower demand on weekends can be resolved through the inclusion of specific variables, which take a value of 1 on that particular day and 0 on other days. The specific variable will shift the regression line downwards on weekends and holidays to reflect the lower levels of peak demand on those days. Model specification can also vary between DNSPs. For example, Energex includes in its system maximum demand forecasting model an interaction term between real electricity prices for customers and businesses, and maximum temperatures.

Source: Ergon Energy.

Bottom-up forecasts – Ergon Energy

Ergon Energy prepares a 10-year maximum demand forecast for system-level, bulk supply points and transmission connection points from a top-down perspective. All zone substations are forecasted separately and reconciled with the system level forecast. The summer and winter maximum demand model is the same as the model outlined in the box above, with the exception that the GSP term is dropped. The model explains the season daily maximum demand for a network asset as a function of a constant term together with forecast maximum and minimum temperatures. Other drivers are considered either too volatile for model inclusion, or data is not available. Similar to the system maximum demand model, specification of the model can vary, taking account of calendar effects (for example, the inclusion of dummy variables for weekends).

The zone substation model uses metered daily maximum demand history, unadjusted for PV to calculate historical PoE values and consequent growth rates. To produce a forward-looking forecast, the latest seasonal peak demand (adjusted) is used as the starting point for the forecast, with a simulation

[293] Ergon Energy Corporation (Network), n.d.

methodology that takes into account the growth rate, the system forecast, new major loads and Ergon Energy configuration changes.

While solar is included in the forecasts through measured historical loads, the intermittency of solar means that it will have a variable coincidence with peak demand, particularly as different parts of the network peak at different times. Because Ergon Energy operates the network under all conditions and builds to peak demand, forecasts of peak demand represent the worst-case probable peak — considering impacts of all variables.

The forecast process and use of PoE effectively negates any impacts of solar on zone substation forecast peak demand.[294] Solar does not have a delay benefit because it does not impact on forecast peak demand and, therefore, solar does not alter the time (the year) at which an asset is identified as being capacity constrained.

While solar is integrated into the systemwide maximum demand forecasts, integration into the zone substation forecasting process is being progressed.

Relative to the systemwide peak demand forecasts, zone substation forecasts show greater variability consistent with the greater variance in observed growth rates. At higher levels of network aggregation, demand shocks and other factors influencing variance are more muted because of the effects of diversification across a larger customer base. For example, a level of network aggregation that is more spatially diversified reduces forecast variance due to weather patterns.

Ergon Energy expects that once the zone station forecasting process more explicitly includes solar, solar is likely to impact on the probability or confidence in the forecast peak demand (for substations with a day-time peak and significant residential PV connection), but solar is unlikely to vary that forecast peak demand level.

In those instances where solar might provide a forecast reduction in peak demand and the zone substation is capacity constrained, Ergon Energy has a program of offering targeted incentives through the Network Capacity Incentive Map, which tightly targets incentives for peak reduction to the specific circumstances of a locality.

Ergon Energy produces maximum demand forecasts for its distribution feeders using the information and procedure outlined in Box 37. Two-year forecasts of maximum utilisation are used to identify constraints. Where constraints are identified, Ergon Energy calculates:

- the amount by which the relevant planning utilisation level is exceeded after the two forecast years; and
- the amount of megawatts required to reduce the feeder below the required planning utilisation level.

[294] Information return to QPC and email correspondence.

Box 37: Ergon Energy distribution feeder forecasts

Ergon Energy has a range of distribution feeder voltages, including 11kV, 22kV and 6.2kV three-phase, and SWER voltages of 12.7kV, 19.1kV, and 11kV.

Distribution feeder forecast analyses carry additional complexities compared to sub-transmission forecasting. This is mainly due to the more intensive network dynamics, impact of block loads, variety of loading and voltage profiles, lower power factors, peak loads tending to peak at different times and dates and the presence of phase imbalance. Also, the relationship between demand and average temperature is more sensitive at the distribution feeder levels.

At the macro level, the forecasting drivers are similar as those related to substations, such as economic and population growth, consumer preferences, and solar PV systems. Accordingly, Ergon Energy uses a combination of trending of normalised historic load data and inputs including known future loads, economic growth, weather, municipal development plans and so on to arrive at load forecasts. Normalising is used to smooth out the effect of short-term effects or abnormal situations.

The information used to generate distribution feeder forecasts include:

- historic maximum demand values to determine historical demand growths;
- historical customer numbers on the feeder to determine historical customer growth rates;
- temperature and humidity data, at the time of historical maximum demands, when taking into account weather impacts to determine approximate 10 and 50 PoE load levels; and
- forecast information from discussions with current and future customers, local councils and government.

The methodology used for calculating constraints on feeders is as follows:

- The previous maximum demands are determined from historical metering / SCADA data for each feeder. These maximum demands are filtered to remove any temporary switching events;
- Future forecast demands for each feeder are calculated based on the information above;
- The worst utilisation period (summer day, summer night, winter day or winter night) is calculated by dividing the period maximum demand by the period rating. This is the determining period which will trigger a constraint;
- Maximum utilisation is forecast out to two years. The year and season is recorded if/where the maximum utilisation exceeds security criteria; and
- The amount of exceedance of the relevant planning utilisation level is calculated after the two forecast years (in MVA). Also calculated is the amount of megawatts required to reduce the feeder below the required planning utilisation level.

Source: Ergon Energy 2015b, pp. 78–80.

Bottom-up forecasts – Energex

Energex prepares individual maximum demand forecasts for each zone substation, bulk supply substation and connection point in order to identify and analyse network limitations. A forecast for each individual network asset is required, because it is constraints on that asset which triggers augmentation or other response planning, and not the system maximum demand forecast. Responses to capacity limitations are driven by the need to ensure security and reliability of supply at substations and feeders.[295]

Where growth in maximum demand remains subdued at a system level, such as in recent years, significant growth can still occur at a localised level where a multitude of very different factors are driving responses, including:

- continued strong maximum demand growth at the zone substation level, in various pockets of the network, which requires reinforcement investment;
- the establishment of new suburbs, which requires extensions to the existing network and can indirectly lead to reinforcement investment further up the network;
- replacement life-expired assets; and
- safety upgrades.

[295] Energex 2014.

Energex prepares maximum demand forecasts for 11 kV distribution feeders on a feeder-by-feeder basis. A feeder load starting point is established by undertaking bi-annual 50 PoE temperature corrected load assessments (post-summer and post-winter). This involves the analysis of daily peak loads for day and night to identify the load expected at a 50 PoE temperature, after first identifying and removing any temporary (abnormal) loads and transfers.[296]

The summer assessment covers the period from 1 November to 31 March, and the winter assessment from 1 June to 31 August. Growth rates are applied and specific known block loads are added; events associated with approved projects are also incorporated (such as load transfers and increased ratings) to develop the feeder forecast. A 10 PoE load forecast is also developed and used for determining capacity and voltage limitations.

Utilisation under normal operating conditions is measured as the forecast 50 PoE load divided by the NCC rating. If utilisation is greater than the TMU, then the network asset does not meet the security standard.

Energex has included solar PV, battery storage, electric vehicles and demand management drivers into future zone substation and feeder growth rates.

Energex considers that solar is likely to be generating on peak demand days (daytime peaks generally occur on bright sunny days). Solar PV generation is incorporated as part of the historical load for each zone substation that peaks during the day. On those substations or distribution feeders where solar has reduced maximum peak demand, or to the extent that it has, the impacts of solar on peak loads are reflected in lower maximum demand PoE forecasts and utilisation rates (50 PoE/NCC). This means that the period of time before a capacity constraint is identified (capacity utilisation is greater than TMU) is longer than it otherwise would be. [297]

The impact solar PV is having on the peak demand of zone substations and feeders is limited at best, as the majority of residential feeders that peak in the day peak in the late afternoon.

Options for responding to network constraints

Network constraints are generally locational and often limited to individual substations or feeders. The network benefit provided by embedded generation is often a function of the type of network constraint (for example, thermal capacity or equipment fault level ratings), the network load profile (that is, the time and duration of peak demand) and the characteristics of the embedded generator (availability, size, connection voltage, and location).

In response to identified network constraints, DNSPs have many different options available to address the constraints. Ergon Energy notes that possible solutions to feeder constraints include (in approximate order of preference, based on network cost):

- network reconfiguration:
  - transferring existing load to adjacent feeders if capacity is available;
  - re-rating or dynamic rating of the underground exit cable or overhead feeder;
- demand management initiatives that reduce customer loading:
  - energy-efficient appliances;
  - power factor correction;
  - residential time-of-use demand price signals under Tariff 14;

[296] Energex 2015c, p. 57.
[297] Energex 2014, p. 39 of Appendix 16.

  - shift loads (for example, pool pumps, hot water storage systems etc.) to control tariff T33;
  - shift loads to tariff T12 (non-control price signal tariff);
  - air-conditioning ‘Peak Smart’;
  - customer micro-embedded generation units;
  - call-off load (loads that can be reduced on an 'on-call' basis to reduce peak demand);[298]
  - commercial and industrial demand management;
  - network and customer embedded generation to reduce peak demand;
  - energy storage;
- network augmentation:
  - replacing the underground exit cable or overhead feeder; and
  - creating new substations and/or feeders and transferring existing load.[299]

In each instance, actual solutions are subject to a detailed study and business case.

Small-scale solar PV is not considered as an option for addressing identified network capacity constraints because of its intermittency:

> *[T]he intermittency of solar means that it is not considered for investment driven by exceeding planning security criteria.*[300]

Network constraints

Forecasts for the current regulatory period

For the current regulatory period, Ergon Energy forecast that peak demand will increase slowly in line with Queensland's economic forecasts, with higher growth for specific zone substations dependent on local economic conditions.[301] Taking into account temperature variations, revised economic growth forecasts, and the take-up rate of air-conditioning and solar PV systems, Ergon Energy revised downwards its systemwide maximum demand forecasts from previous forecast estimates constructed for the regulatory determination period. Average growth in system demand from 2016 to 2021 was forecast at 0.41 per cent per year.

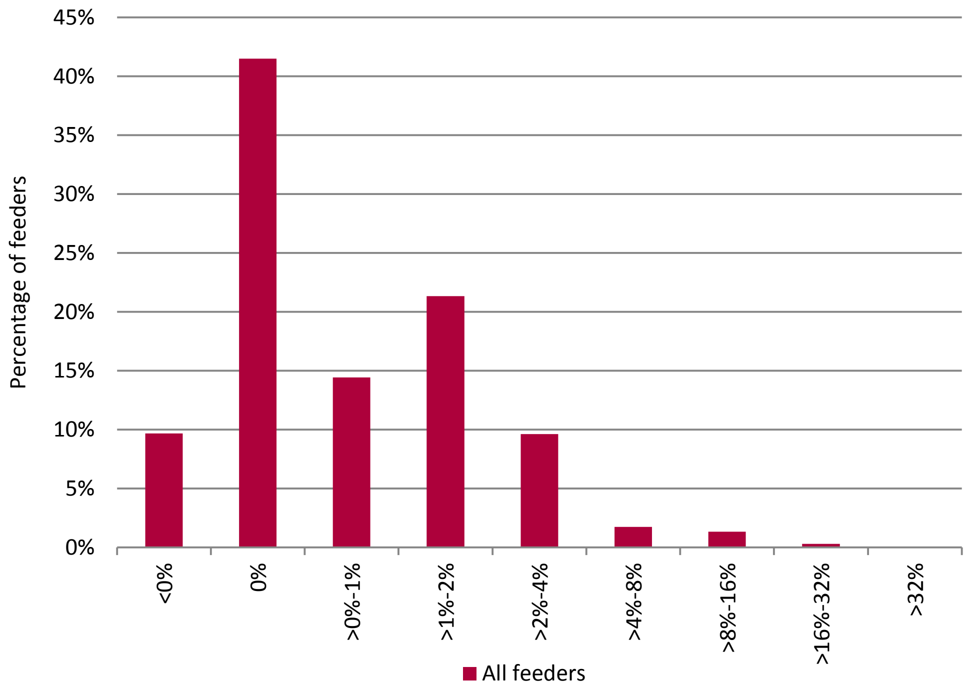
Energex also forecast slow growth in system maximum demand, with annual growth rates of between 0.40 and 1.30 per cent over the period 2016–17 to 2019–20. Key drivers were moderate economic growth, weather patterns (such as milder and wetter conditions prevailing over recent summers), and consumer response to increasing electricity prices.[302] Below the system level, demand growth rates vary significantly:

> *While growth in demand has remained static at a system level, there can be significant growth at a localised substation level. In the 2015/20 period approximately 47 per cent of substations have no average compound growth rate while 11.7 per cent of zone substations have 1 to 3 per cent average annual compound growth rate.3.9 per cent of zone substations have an annual compound growth rate exceeding 3 per cent for the period 2015/20.*[303]

[298] See https://www.ergon.com.au/network/manage-your-energy/incentives, accessed on 9/06/2016.
[299] Ergon Energy Corporation (Network) 2015b, Appendix B: 4.
[300] Ergon Energy return to the QPC information request.
[301] Ergon Energy Corporation (Network) 2015b, p. 71.
[302] Energex 2015b, p. 57.
[303] Energex 2015b, p. 54.

System maximum demand forecast growth is reflected in the forecasts for 11 kV distribution feeders. Energex forecasts that 97 per cent of distribution feeders will have average annual growth in peak demand of less than 4 per cent over the current regulatory period (Figure 70). Fifty-two per cent are forecast to have a zero or negative growth rate in peak demand.

Figure 70: Energex distribution feeder forecast growth in peak demand, 2015–16 to 2019–20



Source: Energex 2015c; QPC calculations.

Identified constraints for the current regulatory period – Energex

Over the current regulatory period to 2019–20, Energex expects that very few network assets will be subject to a constraint.

Under system normal conditions, no bulk or zone substations are forecast to have load at risk (LAR) based on the expected completion of committed projects[304] (Table 45). The information in the table is based on approved projects only, included in Energex's DAPR. The projects address a forecast network limitation. Energex also has 25 substations with potential or emerging limitations being monitored.

In 2016–17, only 11 of 2089 distribution feeders are forecast to face a network limitation. Energex advises that only two of the feeders face a network capacity limitation. A range of other distribution feeders are being monitored as potential emerging limitations.[305] However, Energex advises that the limitations generally require refurbishment of assets, rather than being related to a capacity constraint potentially requiring network augmentation.

[304] At the time of the writing of DAPR (2015), 48 projects were underway to address feeder limitations. These projects are listed in section 4.5, volume II.

[305] See Energex 2015c, section 4.6.

Table 45: Energex network limitations, 2015–16 to 2019–20 (approved projects only)

		2015–16 forecast	*2016–17 forecast*	*2017–18 forecast*	*2018–19 forecast*	*2019–20 forecast*
Substation limitations						
Substation type	*Substation condition*					
Bulk supply substation	LARn > MVA[a]	0	0	0	0	0
	LARc > MVA[b]	1	1	0	0	0
	Total substations[c]	*42*	*42*	*42*	*42*	*42*
Zone substation	LARn > MVA[a]	0	0	0	0	0
	LARc > MVA[b]	1	2	4	4	4
	Total substations[d]	*246*	*247*	*247*	*247*	*247*
132 kV and 100kV transmission limitations						
System configuration	*Feeder condition*					
Normal 10 PoE	LARn > 0 MVA[a]	0	0	0	0	0
Contingency 50 PoE	LARc > 0 MVA[b]	1	0	0	0	0
Total feeders		*122*	*123*	*125*	*125*	*125*
33 kV Sub-transmission limitations						
System configuration	*Feeder condition*					
Normal 10 PoE	LARn > 0 MVA[a]	0	0	0	0	0
Contingency 50 PoE	LARc > 0 MVA[b]	7	7	8	8	8
Total feeders		*402*	*401*	*401*	*401*	*401*
11 kV distribution feeder limitations						
11kV feeder condition						
Feeders with forecast Target Maximum Utilisation (TMU) limitation		12	11	–	–	–
Total number of feeders[e]		*2088*	*2089*	–	–	–

a *Assessment based on 10 PoE forecasts and Customer Outcome Standard. 'MVA' is 1,000,000VA. A volt-ampere (VA) is the unit used for the apparent power in an electrical circuit. Equipment ratings are defined in MVA because this takes into account both real and imaginary power requirements.* ***b*** *Assessment based on 50 PoE forecasts and Customer Outcome Standard.* ***c*** *The bulk supply substation total count includes Powerlink-owned 33 kV connection points.* ***d*** *The zone substation total count includes dedicated customer substations.* ***e*** *Total number of feeders excludes dedicated customer connection assets.*

Note: All information as at 30 November each year.

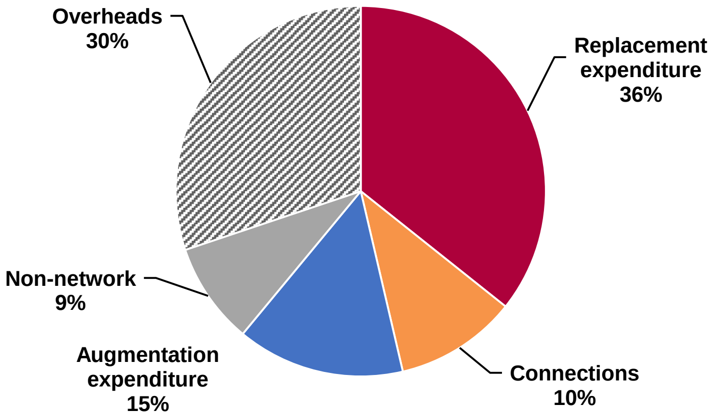
Source: Energex 2015c.

Energex's augmentation capital expenditure for the 2015–16 to 2019–20 regulatory period is driven by the need to address localised increases in peak demand, improve the reliability of worst performing feeders, mitigate power quality issues and purchase land and easements for the long term development of the network. The scope and timing of augmentation is based on an analysis of network constraints, network risks and customer impacts.

The overall drop in security driven capital expenditure for the 2015–20 period is consistent with forecast weak growth in peak demand and recent reforms to security standards introduced in the Distribution Authority of DNSPs. [306]

The total augmentation capital expenditure approved for the regulatory period represents only 15 per cent of total capex, or 21 per cent of direct capex (Figure 71). The main driver in Energex's current capital program is asset replacement.

Figure 71: Energex forecast capital expenditure for the 2015–16 to 2019–20 regulatory period



Source: Energex return to the QPC information request.

Identified constraints for the current regulatory period – Ergon Energy

As at 30 June 2015, Ergon Energy forecast that 141 distribution feeders would face a capacity constraint after two years, out of a feeder network of 1185 feeders (Table 46). While data is not available on the time of peak demand on these feeders, analysis of zone substation data in following sections can infer that a large proportion of the feeders do not have daytime peaks.

[306] A Distribution Authority provides DNSPs with the authority under the *Electricity Act 1994* to operate an electricity distribution network in Queensland. A Distribution Authority also sets out minimum service standards and the requirement for a DNSP to report their performance against the standards. The Electricity Network Capital Program (ENCAP) review was commissioned by the Queensland Government in 2011. The ENCAP review established an independent panel to undertake a review of the capital infrastructure programs of Energex, Ergon Energy and Powerlink with the view to achieving improved efficiencies and cost savings while maintaining network security and reliability. The panel made a number of recommendations that were endorsed by the Queensland Government, including revision of the network security standard. The panel considered that the previous network security standards: were overly prescriptive; had resulted in over-engineering of the network and driven excessive capital and operating costs; had not sufficiently involved economic analysis of the benefit of network capital expenditure relative to outcomes that are acceptable to customers in terms of both reliability and cost; and had driven excessive increases in network tariffs that affect the affordability of electricity supply for households and business (Independent Review Panel on Network Costs (2012)).

Table 46: Ergon Energy distribution feeders with forecast limitations

Region	*Total feeder numbers**	*Total capacity constraints***	*Total forecast capacity constraints* (after 2 years)*
Far North	148	6	6
North Queensland	305	38	43
Mackay	149	6	8
Capricornia	203	19	24
Wide Bay	169	20	22
South West	211	37	38
All Regions	*1185*	*126*	*141*

*Notes: Forecast constraints as at 30 June 2015. * Dedicated customer connection assets are excluded. ** Capacity constraint identified against the Security Criteria loading. Includes feeders with committed projects to address the constraint.*

Source: Ergon Energy Corporation (Network) 2015b, p. 80.

Only one of Ergon Energy's 258 zone substations was forecast to fall short of meeting its Security Standard over the current regulatory period to 2019–20. That substation had a recent peak at 6.30 pm, so that solar PV provided no contribution to delaying the constraint.[307] Zone substation 10/50 PoE load forecasts relative to NCC ratings for Ergon Energy are analysed in Chapter 8.

Solar and investment delay

A number of hypothetical case studies were developed to illustrate how solar may defer the timing of projects that address network capacity constraints.

Energex distribution feeders

On Energex's network, only two 11 kV feeder committed projects have a forecast limitation because of a capacity constraint. However, 11 feeders are being monitored where the nature of the constraint is based on a capacity limitation.[308]

The limitations on these feeders are emerging limitations forecast to potentially occur in the next couple of years. As such, no project costings are available. The typical costs of augmentation projects to overcome 11 kV limitations can vary quite significantly, but could be in the range of $50,000 to $1 million per feeder depending on the particular situation.

To determine if solar PV generation has (to date) had an impact on deferring these emerging limitations, it is necessary to consider the time of day that the limitation is occurring and the number of customers with solar PV generation connected to the feeder. It is also necessary to make some assumptions around the amount of actual solar PV generation that is likely to occur on a given day.

If a feeder capacity limitation occurs at night, then solar PV generation will not provide any benefit in overcoming the limitation (battery storage systems may change this in the future). Six of the 11 feeders have summer night limitations. Therefore, installed solar capacity on these feeders provides no delay benefit.

[307] Ergon Energy Zone Substation Forecast workbook for Ergon Energy 2015 DAPR 2015–16 to 2019–20. This workbook provides detailed forecast information for each zone substation. It can be accessed at https://www.ergon.com.au/network/network-management/future-investment/distribution-annual-planning-report.

[308] See the 11 feeders listed in Energex 2015c, p. 51.

The five remaining feeders have summer daytime limitations (that is, the summer limitation occurs during PV generating hours). To analyse the potential impact of solar on these feeders, the process outlined in Box 38 was applied.

Box 38: Calculation of the potential investment delay impact of solar PV

To analyse the potential impact of solar on distribution feeders the process outlined below was applied:

- Determine the installed PV inverter capacity connected to each feeder.
- Apply a capacity factor of 80 per cent to the installed inverter capacity (to allow for the fact that most installed solar panel capacities are less than known inverter capacity).
- Apply a solar radiation factor that corresponds to the time of day that the feeder peak load occurs.
- Apply a derating of 40 per cent to allow for the impact of a hot, cloudy day (as occurred on 2 February 2016).
- Compare the number against the load reduction required to defer the investment by one year.

Example calculation for distribution feeder BPN4:

- installed inverter capacity = 0.63 MW;
- 80 per cent capacity factor of 0.63 = 0.504 MW;
- time of peak on feeder is 3.30 pm;
- solar radiation factor for that time of day is 0.58 (at that time, solar radiation is 58 per cent of maximum for the day);
  - 0.504 x 0.58 = 0.292 MW; and
  - derate[309] to allow for a cloudy day = 0.292 x 0.4 = 0.12 MW.

The amount of load reduction equivalent to one-year deferral for this feeder is 0.1 MW.

Comparing the calculated 0.12 MW against the separately calculated required load reduction to defer the constraint 1 year of 0.1 MW, indicates that the impact of solar on this feeder is equivalent to about a 1-year deferral of the capacity constraint.

These calculations were prepared by Energex at the request of the QPC to examine the delay impacts of solar PV. They are hypothetical and do not form part of Energex's normal planning processes.

Source: Energex return to QPC information request.

Adopting this method, the potential deferral benefit of solar for the five feeders is:

- One capacity limitation is deferred by 2 years;
- Two limitations are deferred by 1 year; and
- Two limitations are not deferred by at least 1 year (although feeder PPE6A is close) (Table 47).

Table 47: 11 kV distribution feeders with forecast limitations and daytime peak, 2015–16 to 2019–20

11 kV distribution feeder	*Inverter capacity (MW)*	*Calculated solar impact (MW)*	*Impact required for 1-year deferral (MW)*	*Potential deferral contribution (years)*
BDA12B	0.871	0.28	0.2	1
BPN4	0.63	0.12	0.1	1
BRD13A	2.1	0.24	0.1	2
NSD30B	0.161	0.05	0.1	<1
PPE6A	0.784	0.09	0.1	<1

Source: Energex data.

309 There are many technical and environmental factors that can affect how much power a system can produce. Derating combines and summarises these factors into a single estimated value.

Energex sub-transmission projects

Of the proposed investments in the DAPR, many relate to refurbishment drivers which will not be impacted by solar PV. As a set of case studies, the future (potential RIT-D) sub-transmission projects listed in DAPR 2015 were analysed to help identify any impacts from solar (the projects are listed in Table 48).

It was found that solar was unlikely to have any network benefit in terms of delaying the need for, or the timing of, the projects. This was due to:

- capacity constraints occurring after solar PV has stopped generating;
- new industrial block loads, changes in applicable security standards, and highly variable timing in peaks;
- difficulties in forecasting peak loads involving industrial block loads, such that a forecasting emerging constraint does not eventuate; and
- the combination of the intermittency of some large industrial loads and the intermittency of solar generation.

Table 48: Sub-transmission projects with impending capacity driven limitations, 2015–16 to 2019–20

Project name	*Estimated cost ($m)*	*RIT-D start date*	*Peak time*	*Network impact*
PGN Peregian — Install 2nd 25 MVA transformer	2.2 ±30%	Qtr 4 2015	Predominantly domestic load with peak around 7 pm	Solar provides no deferral benefit
CNA Cooneana — Upgrade 33/11 kV zone substation 2nd module	4.3 ±30%	Qtr 4 2015	Variable due to nature of industrial load	Unlikely to be any deferral benefit. The network driver for this project is primarily new industrial block loads and the subsequent change of security standard applicable to this substation from rural to urban (due to the increase in load density). The industrial nature of the load on this substation is quite variable and peak loads in the past have often even occurred at 7 am.
GNA Goodna — Install 2nd 33/11 kV transformer	3.2 ±30%	Qtr 3 2015	Predominantly domestic load with peak around 7 pm	Solar provides no deferral benefit
FDS Flinders — KBR Kalbar — Establish 33 kV feeder	10.0 ±30%	Qtr 3 2015		The driver for this potential project was large block loads associated with two quarries which were planned to be established in the area. Latest advice is that the quarry load will not occur and this project is not likely to proceed. Even if the limitation were to emerge it is highly unlikely that solar PV could overcome capacity limitations caused by such large industrial loads, due to the intermittency of the loads, the solar generation, and variations in operating hours of such industrial customers.

Notes: The Australian Energy Regulator requires the preparation of a Regulatory Investment Test for Distribution (RIT-D) for network augmentation expenditures greater than $5 million. RIT-D start dates updated to match Energex information return.

Source: Energex 2015b; Energex return to the QPC information request.

Transmission limitations – PowerLink Queensland

An amended planning standard came into effect on 1 July 2014 which permits Powerlink Queensland to plan and develop the transmission network on the basis that some load may be interrupted during a single network contingency event. Powerlink is required to implement appropriate network or non-network solutions in circumstances where the limits of 50 MW or 600 MWh are exceeded or when the economic cost of load which is at risk of being unsupplied justifies the cost of the investment.[310] The amended planning standard has the effect of deferring or reducing the extent of investment in network or non-network solutions required in response to demand growth.

Given the amended standard and forecast weak growth in demand, PowerLink forecasts no significant capacity constraints are likely to be reached over the planning period:

> *Assuming that the demand for electricity remains relatively flat as forecast in this [Transmission Annual Planning Report], Powerlink does not anticipate undertaking any significant augmentation works within the outlook period other than those which could potentially be triggered from the commitment of mining or industrial block loads.*[311]

Factors influencing the impact of solar PV on network constraints

The impact of solar on networks appears more muted than might be expected, for a number of reasons. Furthermore, discerning the direction of the net impact on networks — whether it raises or lower costs and productivity in the aggregate — is difficult, as solar has both positive and negative impacts.

Coincidence of solar generation and maximum peak demand

Analysis of zone substations data

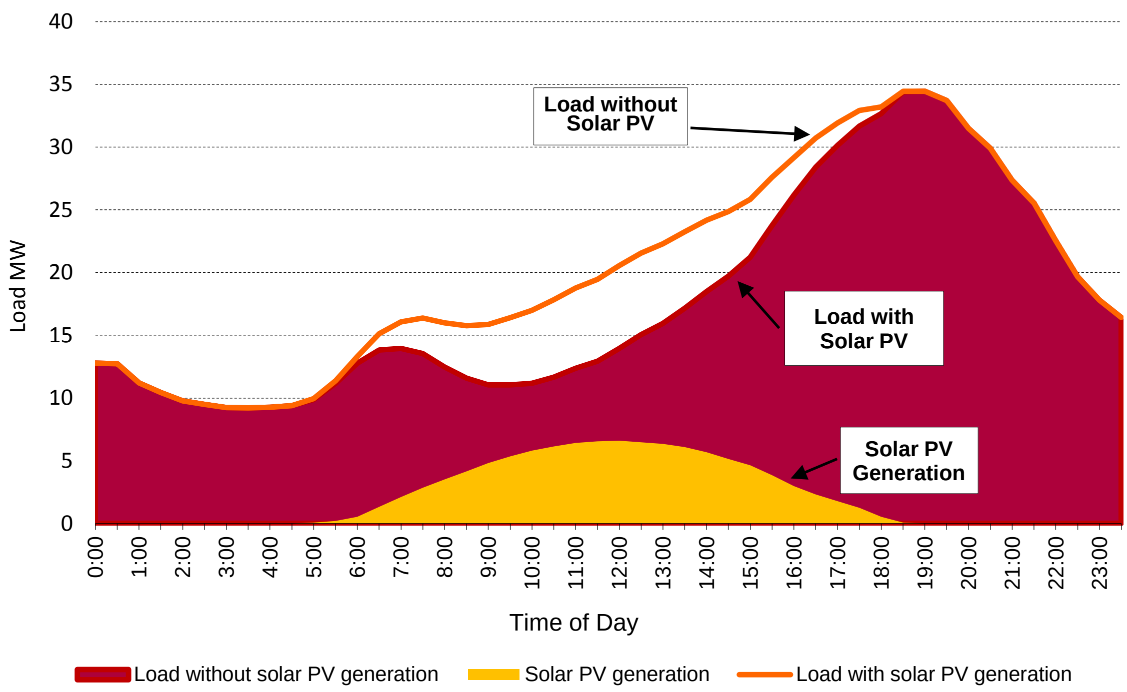
Solar can only impact on network constraints where it impacts on peak demand. Solar can have two types of impacts on peak demand:

- Tariff structures can provide incentives for consumer behaviours which shift load to the peak, thereby raising the peak — a negative impact; and
- Solar can reduce the peak of a capacity constrained asset if the peak occurs during daytime generating hours only — a positive impact.

Taking the Arana Hills zone substation as an example, peak demand on the substation occurs after 6 pm (Figure 72), and as such, at the time of the peak, the load profile on the substation with and without solar is the same. The installation of additional solar will provide no benefit in terms of peak reduction. The load profile and capacity conditions in the figure below are representative of a large number of Queensland zone substations.

[310] PowerLink Queensland 2015, p. 10.
[311] PowerLink Queensland 2015, p. 52.

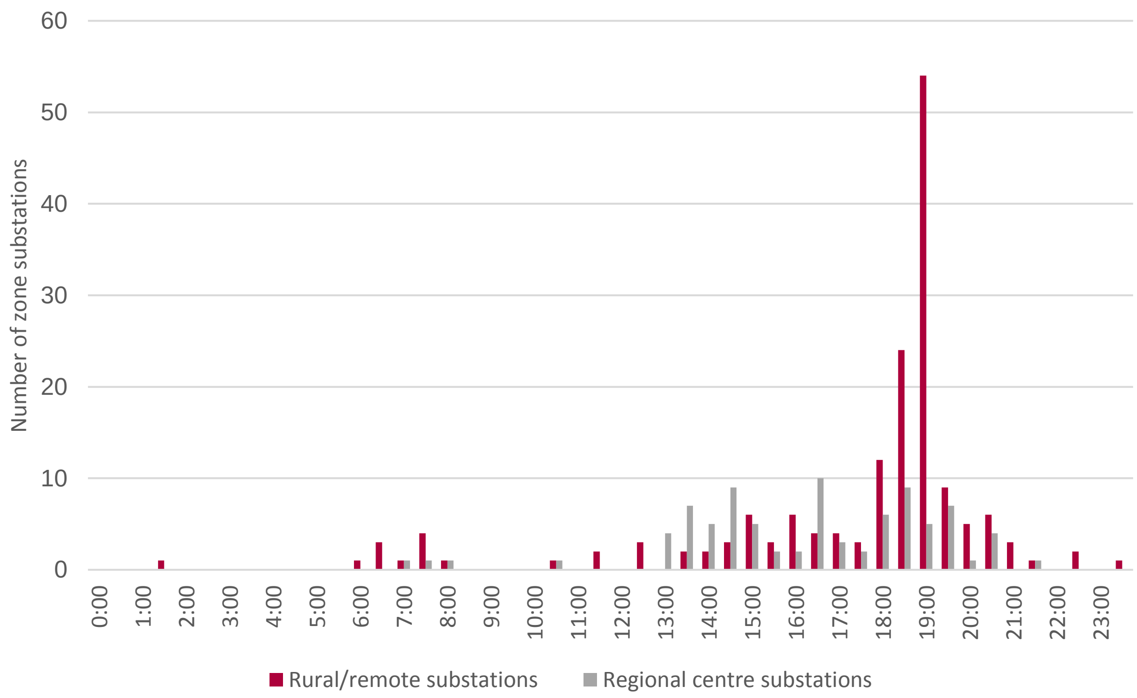
Figure 72: Arana Hills zone substation load with and without solar PV, 2014–15



Source: Energex data.

On Ergon Energy's network, 71 per cent of rural and remote zone substations had a peak that occurs between the hours of 6 pm and 6 am (Figure 73). The proportion for regional centre substations is lower at 38 per cent due to the greater influence of commercial and industrial activities that have daytime peaks.

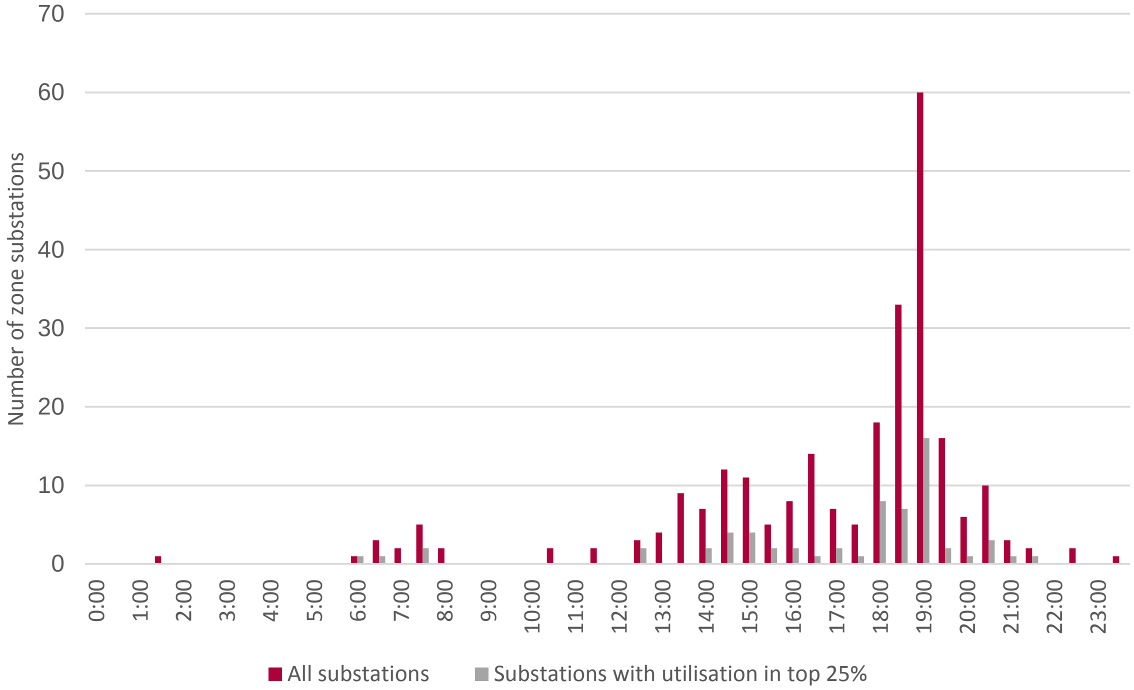
Figure 73: Time of day of peak demand for Ergon Energy zone substations



Note: Peak based on latest peak compensated load from 2014–15.
Source: Ergon Energy Corporation (Network) 2015b.

For zone substations that have utilisation rates in the top 25 per cent of all Ergon Energy zone substations, 64 per cent have peaks after 6 pm (Figure 74).

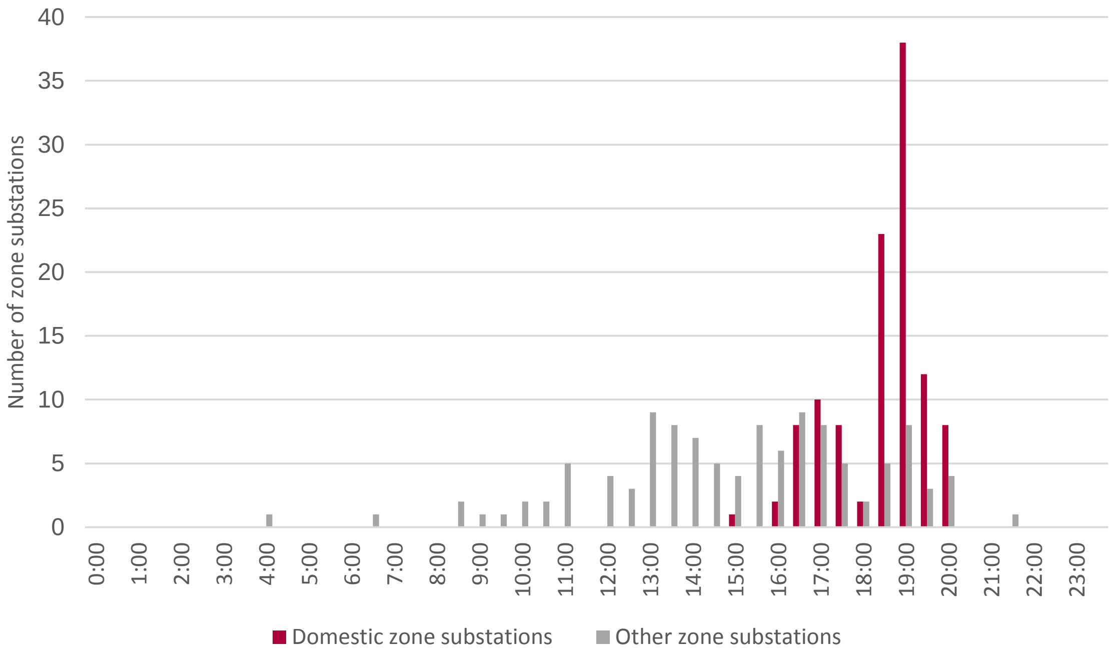
Figure 74: Time of peak at Ergon Energy zone substations with relatively high utilisation rates[a]



Notes: [a] Zone substations in the future form the top 25 per cent of substations in terms of network utilisation. Utilisation measure based on 50 POE MVA / NCC Rating MVA. While higher than for the other 75 per cent of zone substations, the utilisation rates are below Ergon Energy's security standard for all but one of the substations.
Source: Ergon Energy Corporation (Network) 2015b; QPC calculations.

For the Energex network, the proportion of domestic zone substations with peaks after 6 pm was 74 per cent in 2014–15, and 21 per cent for 'other' substations which includes industrial, mixed industrial and mixed domestic substations (Figure 75).

Figure 75: Time of day of peak demand for Energex zone substations, 2014–15



Source: Energex 2015c; Energex data; QPC calculations.

The Energex DAPR 2015 identifies 31 zone substations with forecast constraints over the current regulatory period (14 substations are domestic and 17 are 'other' zone substations). Of the 14 domestic zone substations, only two had a peak that occurred during daytime generating hours.

Energex's DAPR identifies a distribution feeder peak as 'summer day', 'summer night', 'winter day' or 'winter night'. The DAPR does not identify the specific half-hour period of peaks. Peak readings are taken at each substation and for the entire Energex network (the sum of all connections points). Day measurements are averaged in 30 minute increments beginning at 7.30 am and ending with the half hour beginning at 4.30 pm. Night measurements are averaged in 30 minute increments beginning at 5 pm and ending with the half hour beginning at 7 am. As peak demand at individual substations will not always occur in the same 30 minute period, peak demand at some substations will not coincide with system peak demand.

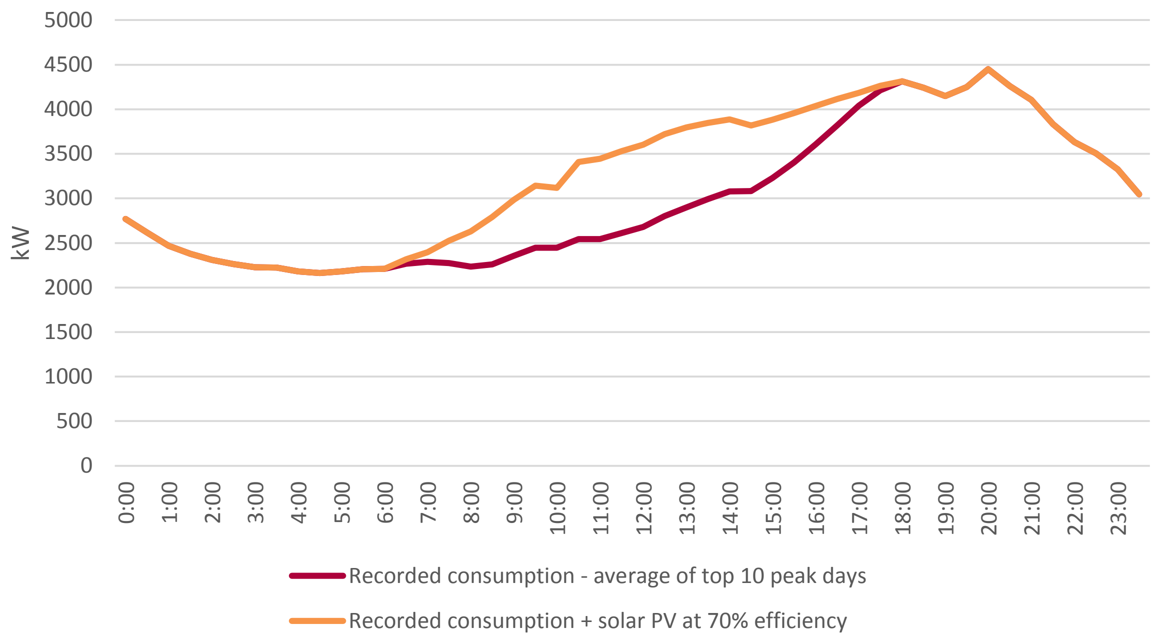
Of Energex's nearly 2100 distribution feeders, 49 per cent are identified as having a night peak. Many others peak near the end of the day, between 4 and 5 pm, when solar is generating, but it is happening at a low rate of output.

Analysis of distribution feeder data

Several distribution feeders and transformers typically feed a single zone substation. A zone substation may not be experiencing a constraint, but a feeder might be. There is sufficient data to analyse peak times and installed solar capacity at the level of zone substations, but equivalent data is not available for analysis of most distribution feeders (or is not available within the timeframes of this inquiry). Therefore, a case study approach has to be adopted where monitoring is in place.

For example, BO-03 is an Ergon Energy feeder with capacity constraints and the potential for reverse flows. Solar PV estimated generation is 239 per cent of the estimated minimum daily load on the feeder over the course of 2014–15. Peak load on the feeder occurs when solar is generating minimal output (Figure 76).

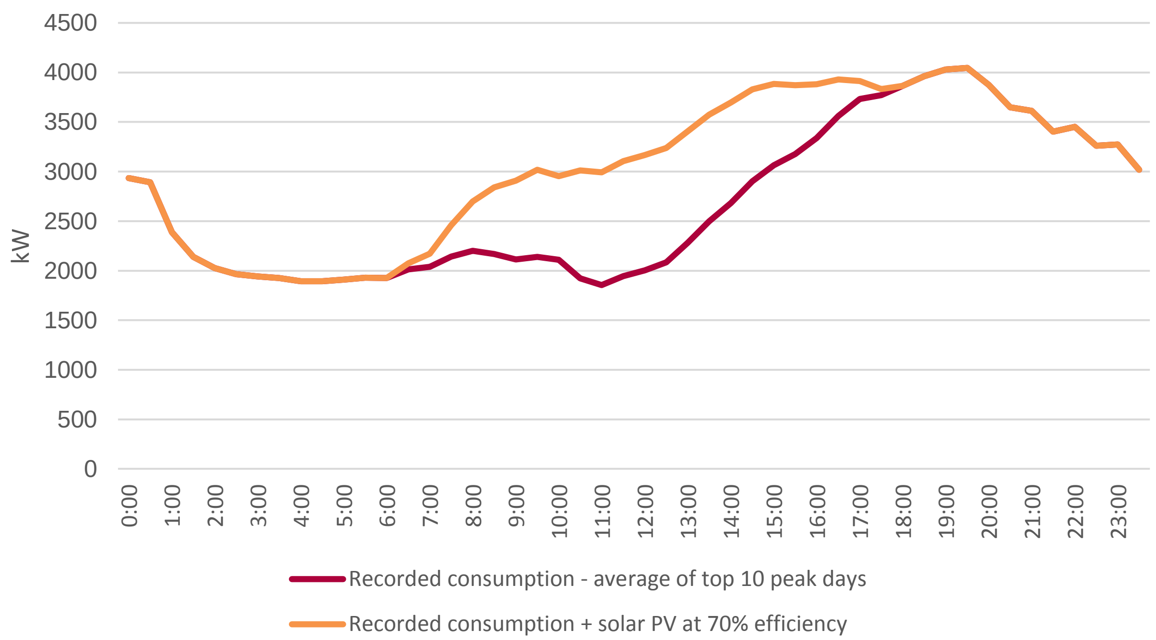
Figure 76: BO-03 feeder peak days with and without solar PV, 2014–15



Source: Ergon Energy return to the QPC information request.

The PB-B Dundowran feeder provides a similar example (Figure 77). This feeder does not have a capacity constraint but has an estimated PV generation to minimum daily load percentage of 319 per cent.

Figure 77: PB-B Dundowran feeder peak days with and without solar PV, 2014–15



Source: Ergon Energy return to the QPC information request.

Solar PV may provide delay benefits beyond the current regulatory period. The potential for these benefits depends on existing capacity utilisation rates, the rate of growth in peak demand, and the resulting time period until constraints are reached.

To examine existing utilisation rates and future capacity constraints on Energex's 11 kV distribution feeders, three scenarios were constructed:

- The baseline scenario assumes observed DAPR forecast growth rates for the period 2015–16 to 2019–20 are held constant into the future.
- Scenario 1 assumes a minimum growth rate of 1 per cent, and DAPR forecast growth rates greater than 1 per cent are doubled (for example a 2 per cent forecast growth rate is doubled to 4 per cent) and held constant into the future.
- Scenario 2 assumes a minimum growth rate of 2 per cent, and DAPR forecast growth rates greater than 1 per cent are doubled and held constant into the future.

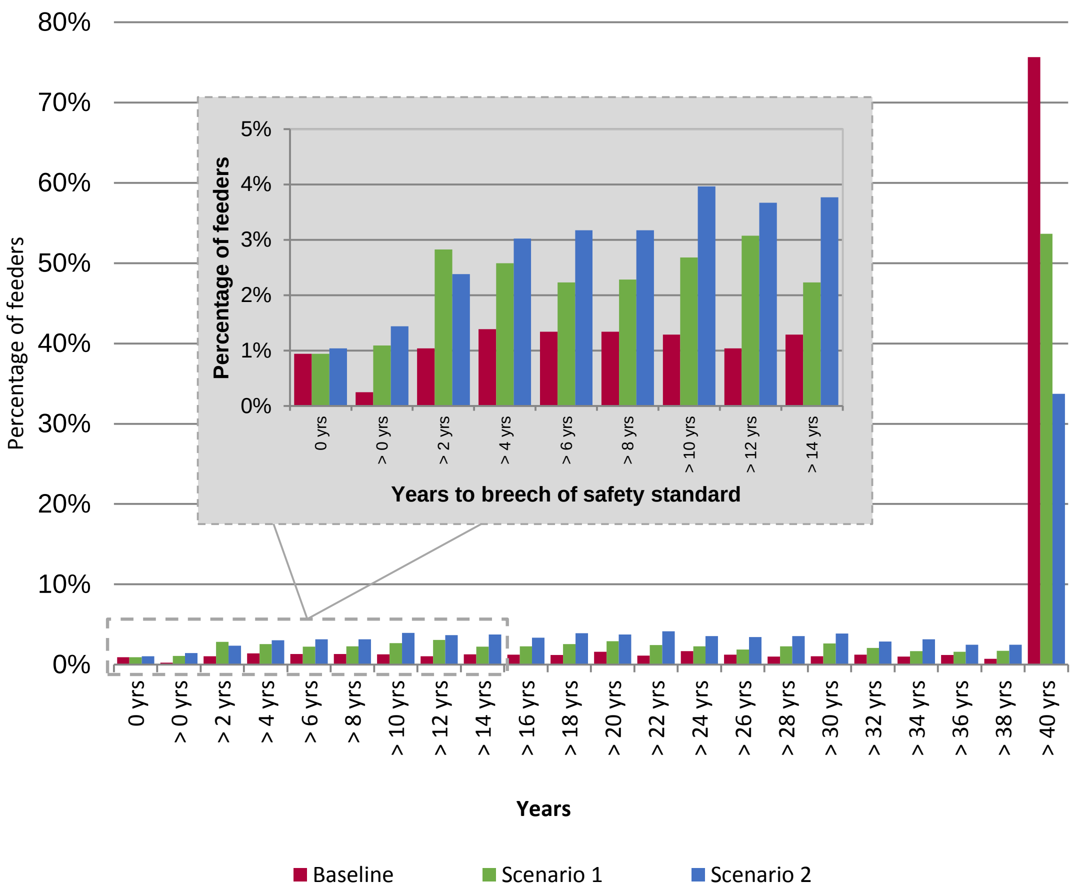
Under the baseline scenario, only 10 per cent of feeders would reach their TMU within 14–16 years, with over 75 per cent of the almost 2100 feeders taking more than 40 years to reach their TMU.

Under scenario 1, with the growth rates more in line with historical levels, 20 per cent of feeders reach their TMU within 14–16 years, with 54 per cent not in danger of breaching their safety standard for more than 40 years.

Under scenario 2, 26 per cent of feeders could be expected to meet or exceed their TMU within 14–16 years, with 34 per cent of feeders taking greater than 40 years to reach their TMU.

Under each of the scenarios modelled, no more than 4 per cent of feeders would be constrained in any two-year period (Figure 78).

Figure 78: Years to breech of safety standard, Energex distribution feeders

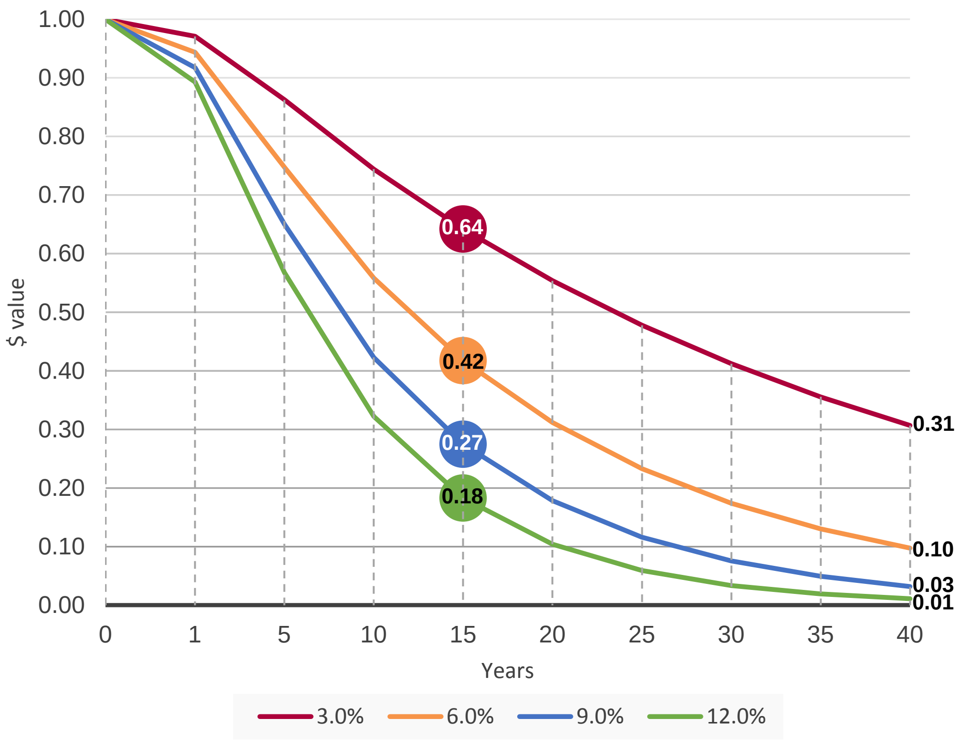


Source: Energex 2015c; QPC calculations.

As many network assets will not become capacity constrained until well into the future even under high peak demand growth rate assumptions, discounting becomes an important consideration. The NPV of a delay benefit far into the future is worth less than a delay benefit which occurs sooner. At a discount rate of six per cent, one dollar 15 years from now is only worth 42 cents today (Figure 79).[312]

Actual cost savings in the future will depend on the best, or least–cost, option to address the constraint at the time, as well as the requirement that solar generation should coincide with daytime peaks.

Figure 79: Value of $1 — the effect of discounting



An alternative approach to analysing the number of years until a capacity constraint is reached under various growth rate assumptions is to analyse the growth rate required to reach a capacity constraint within a fixed period of time. The current state of technology, consumption behaviours and regulatory standards is assumed to remain constant for the analysis. Given the forecast capacity utilisation rates on 11 kV distribution feeders, and given the TMUs for each distribution feeder, the growth rate required to breach the TMU within 15 years has been calculated for each Energex feeder.

One hundred feeders (or five per cent of feeders) will reach their TMU within 15 years if peak demand on the feeder grows at between 0–1 per cent each year (Figure 80). Over 225 feeders would require an annual growth rate of greater than 10 per cent to reach their TMU. A feeder that requires a 3–4 per cent growth rate to breech its TMU needs to experience a high rate of growth in peak demand each and every year for a 15 year period, an unlikely scenario except in rare cases.

[312] Discounting is discussed further in Appendix D.

Figure 80: Growth rate required to breech safety standard in 15 years

Source: Energex 2015c; QPC calculations.

Capacity constraints and capital investment

Analysis of capacity constraints on zone substations and 11 kV distribution feeders indicates that distribution networks face relatively few capacity related constraints over the current regulatory period. Even if high growth rates in peak demand are assumed going forward, capacity constraints as far forward in time as 3–4 regulatory periods remain modest.

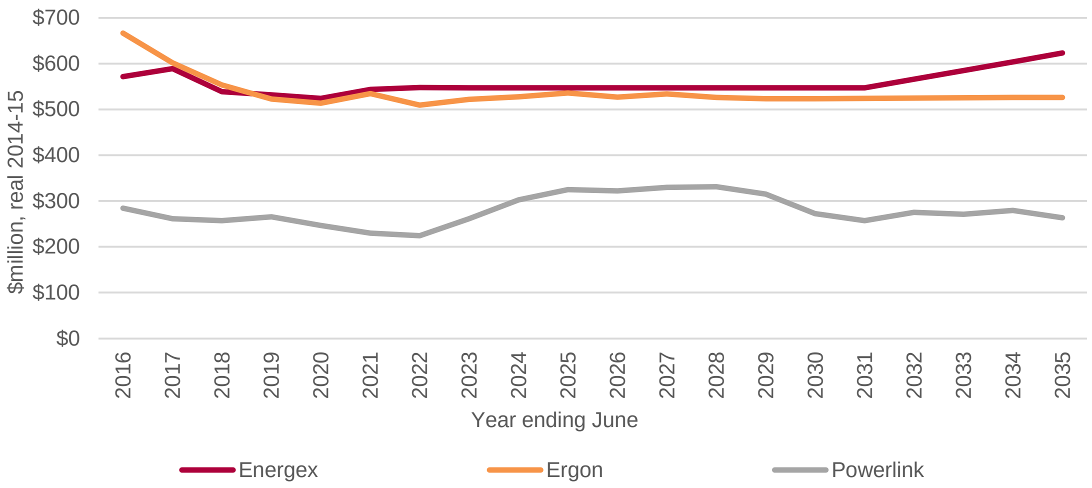
This is consistent with work undertaken by GHD for the QPC's Electricity Pricing Inquiry which found that increases in capital expenditure by DNSPs to address capacity constraints will only be needed towards the end of the forecast period (roughly from 2030–31), as it will take until then for demand to grow sufficiently to exhaust current network capability (Box 39).

Box 39: Projected network capital expenditure

GHD forecast that network costs will fall over the next 20 years, with average real annual costs more than halving, reflecting recent AER determinations and forecast network requirements, primarily driven by capital expenditure (capex). Allowable capex decreased 50 per cent in 2015–16. Over the next 20 years capex is projected to be on average 10 per cent lower in real terms relative to capex in 2015–16.

GHD's assessments indicate that Ergon Energy's and Energex's network costs will continue to be dominated by investment cycles, as assets are replaced or refurbished (Figure 81).

Figure 81: Projected capital expenditure, Queensland network



Source: ACIL Allen modelling results.

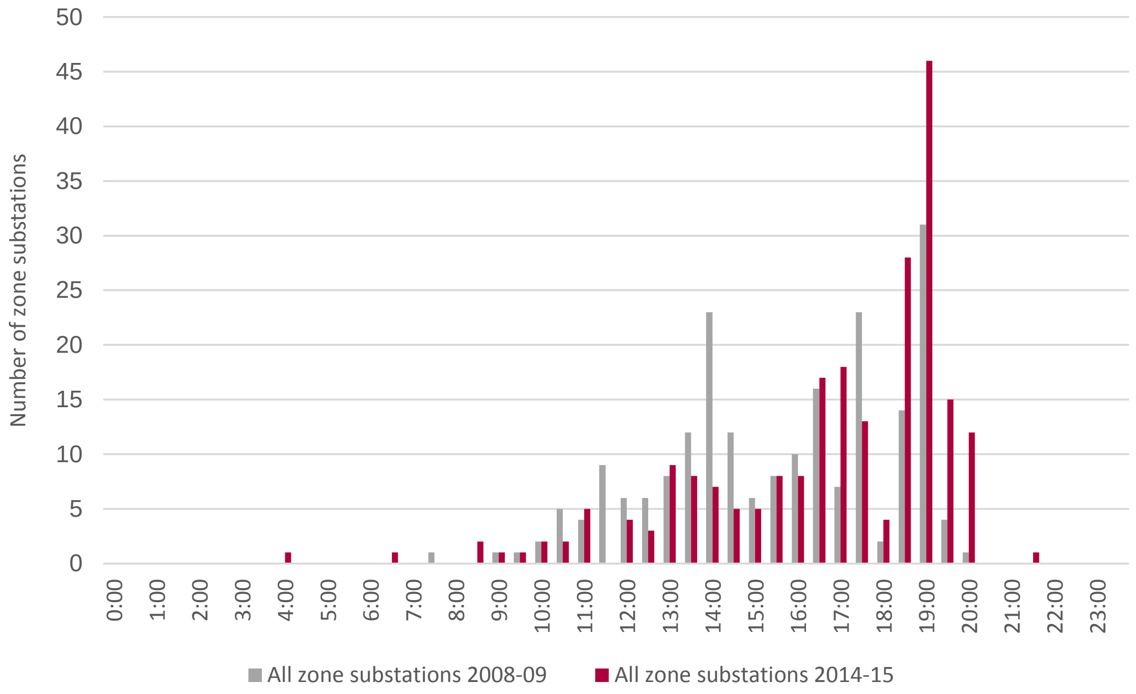
GHD found that peak demand may not be as influential on future network costs as has been the case previously, given excess capacity from previous investment cycles. The increase in expenditure only towards the end of the forecast period reflects the time it is expected to take for demand to grow sufficiently to exhaust current network capability and trigger growth-driven network expenditure. This finding has been informed by analysis of historical demand and expenditure, with adjustments made for the impact of planning criteria.

Source: QPC 2016a.

The shift in the time of day that demand peaks

For Energex zone substations, the time of day of peak demand has shifted to later in the day with many zone substations experiencing peaks between 6 and 8 pm (Figure 82). In 2008–09, the mean peak time for all zone substations (including industrial, mixed industrial, domestic and mixed domestic substations) was 4 pm. By 2014–15, the mean peak time had shifted to 5.30 pm.

Figure 82: Time of peak for Energex zone substations, 2008–09 and 2014–15

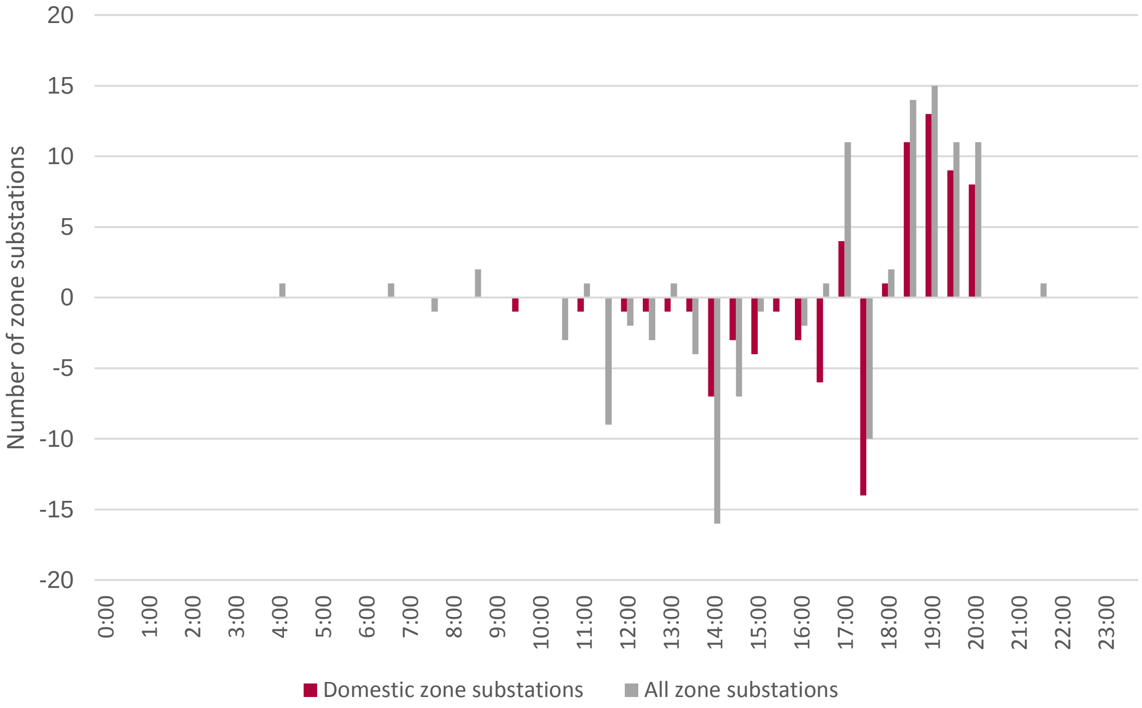


Notes: 211 zone substations are included in the analysis, with 110 substations being domestic. 2008–09 data was not available for 11 substations included in the analysis (e.g. if the substation was new since 2008–09). For these cases, the next closest year of data was used (9 cases used data for 2009–10 or 2010–11, and 2 cases used data from 2011–12).

Source: Energex 2015c; Energex data; QPC calculations.

There has been a large reduction in zone substations with peaks during solar generating hours, and an offsetting increase in peaks at 6 pm or later (Figure 83). For those substations that experienced a shift in peak to later in the day from 2008–09 to 2014–15, the average magnitude of the shift was two hours.

Figure 83: The shift in Energex's peak demand to later in the day, 2008–09 to 2014–15



Notes: For a given time slot the number of zone substations is positive if more substations have a peak at that time slot in 2014–15 compared to 2008–09. A negative number means that fewer substations have a peak at that time slot in 2014–15.
Source: Energex 2015c; Energex data; QPC calculations.

The shift in the number of Energex zone substations with later peaks is expected to continue driving the system peak into the early evening:

> *It is expected that as more solar PV is connected to the network the summer peak will shift into the early evening (residential load peak). In such circumstances solar PV may have no impact on peak demand, particularly at local levels. It is expected that over the next few years that the Energex system peak will occur at 6:30pm as a direct result of the impact of solar PV. At this time of day the contribution of solar PV is minimal and from about 2018 onwards peak demand is unlikely to be affected by solar PV.*[313]

> *It is important to note that while solar PV connections continue to grow slowly the influence of solar PV generation is diminishing as a direct result of the system, peak demand occurring in the early evening. It is anticipated that the summer peak demand will occur at 6:30pm by about 2020. This is [in] alignment with the AEMO summer state peak demand occurring at 7:00pm.*[314]

In 2016, solar was estimated to reduce the system maximum peak demand by 218 MW. Reflecting the above trends, Energex forecast that the contribution of solar to reducing system maximum peak demand would decline steadily so that, by 2021, solar would result in no reduction in system maximum peak demand (Table 49). In other words, the system peak demand load profile chart would resemble the Arana Hills chart shown earlier where peak demand occurred after solar generation had ceased.

The combination of solar PV and battery storage is expected to have an impact on maximum peak demand. Under Energex's base case modelling scenario, battery uptake is forecast to increase from 6 MW in 2017 to 154 MW by 2022. In such a scenario, Energex estimates that solar installations with battery storage systems will produce a contribution to reducing peak demand of 1.6 MW in 2017 increasing to 39.7 MW by 2022.

313 Energex 2015c, p. 37.
314 Energex 2015c, p. 62.

This will partially offset the trend of solar-only installations increasingly having no impact on peak demand because of the shift in time of day of the peak.

Even with the modelled early and strong up-take in battery storage, the net effect is a declining contribution of solar PV to peak reduction. The fall in the contribution of solar-only systems is still much stronger than the contribution provided by new battery investment in combination with solar (218 MW down to 0 MW megawatts by 2021 compared to a storage contribution to peak reduction of 26.3 MW in 2021).

Table 49: Solar PV and battery storage contribution to reducing Energex summer system peak demand

		2016	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*
Solar PV capacity impact on summer system peak demand (MW), DAPR 2015	Reduction in peak (MW)	218	131	54	14	1	0	0
Battery storage in combination with solar peak demand impact		–	1.6	5.4	10.7	17.7	26.3	39.7

Note: Estimates based on Energex's base case scenario used in modelling battery take-up and impact on peak demand. Under the high impact scenario, the peak demand impact of battery storage is to reduce the system peak by 2.3 MW in 2017 increasing to 65.7 MW by 2022.

Source: Energex 2015c, p. 62; Energex forecast data.

The shift in the proportion of network assets peaking outside solar PV generating hours has also been accompanied by an increase in the magnitude of the system peak between 6.30 pm and the more traditional (what was common until recent years) system peak of around 4.30 pm.[315]

The shift in peak demand to the evening is impacting on peak demand at the transmission level. Powerlink peak demand forecasting procedures incorporate the shift to an evening summer peak:

> *This evening series is now used as the basis for regressing as evidence supports Queensland moving to a summer evening peak network due to the increasing impact of solar PV. This move to an evening peak by 2017/18, is supported through an analysis of day and evening trends for corrected maximum demand.*[316]

With large-scale embedded generators there is a process for paying generators where exports to the grid reduce transmission network peak demand (Box 40). The process is sometimes pointed to as providing a model for compensation to be paid to small-scale solar PV. However, given the lack of forecast capacity constraints at the transmission level, and the shift in peak demand to the early evening, the potential for residential solar PV to delay transmission capital investment is not significant. In Powerlink's regulatory proposal to the AER for the regulatory period 2017–18 to 2021–22, of proposed network capital expenditure of $854 million, only $10.8 million was due to load-driven network augmentations.[317]

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[315] Energex system demand forecast data.

[316] PowerLink Queensland 2015, p. 133.

[317] PowerLink Queensland 2016, p. 53.

Box 40: Solar PV and impact on the transmission network

An impact from solar PV is less likely on the transmission network compared to the distribution network:

> *Transmission assets are generally installed in capacity increments that are substantially larger than distribution assets. This means that finding reliable EG projects of sufficient capacity to defer or avoid a discrete transmission augmentation or replacement project would not be a trivial exercise. Successfully deferring or avoiding a transmission project would probably require aggregation services to combine a number of EG project, and potentially also small-scale demand-side response arrangements.* [318]

Notwithstanding this, as part of the consultation process, the Department of Energy and Water Supply queried whether Transmission Use of System (TUoS) charges should accrue to solar PV owners.

The regulatory framework allows for the locational component of TUoS charges to be passed through to certain embedded generators connected directly to the distribution system. These payments are available to large embedded generators whose exports help to reduce peak demand in localised areas of the network.

The National Electricity Rules require that the amount of avoided TUoS payments must be calculated using a 'with and without test', which generally involves:

- determining the locational TUoS charges that would have been payable by the distributor to the transmission business had the embedded generator not injected any electricity into the distribution network
- determining the locational TUoS charges actually payable by the distribution business to the transmission company at the relevant connection point
- calculating the excess of the first TUoS charge over the second TUoS charge. The excess is the amount of avoided TUoS payments.

State regulators across Australia have typically recommended against any form of payment for avoided TUoS as part of solar feed-in tariff arrangements.

In the short term, since the revenue earned by the transmission operator is regulated under a revenue cap with an unders and overs account, avoided TUoS charges are simply recovered in the next financial year from distribution network operators (and therefore through higher prices for customers). In the longer term, the ability of solar PV customers to reduce transmission charges will depend on its capacity to reduce peak demand on the transmission network. At present, a positive impact relies on solar PV generation reliably coinciding with peak demand.

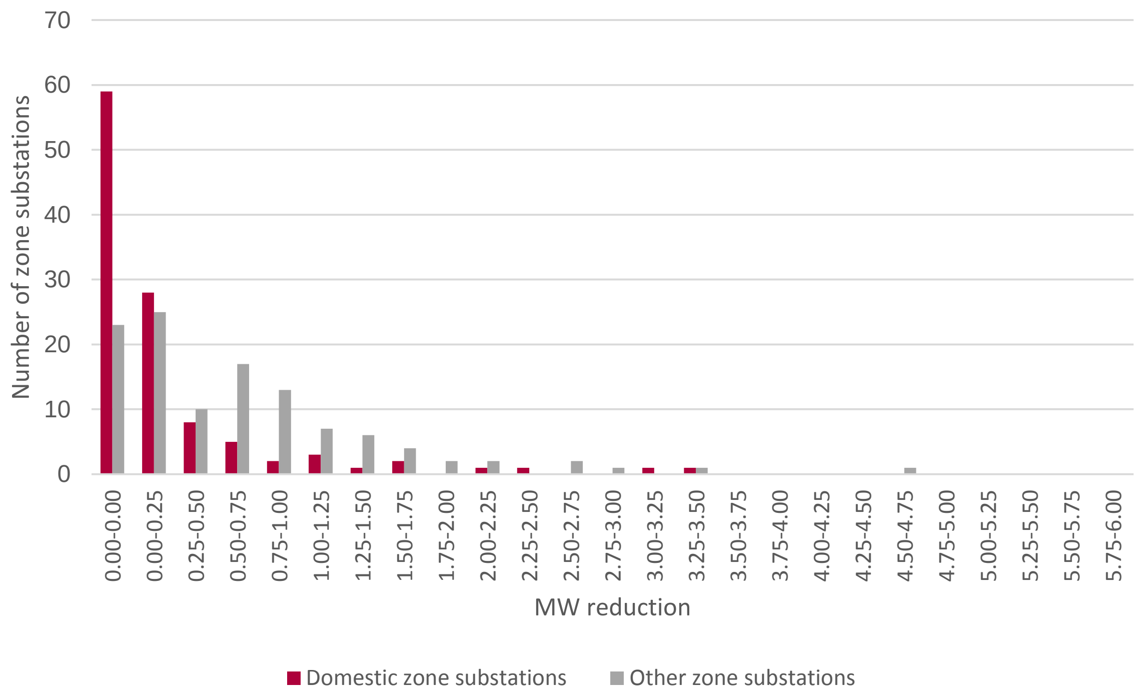
An accurate assessment of the contribution of a solar PV customer would require half hourly data for each customer's exports and peak demand data for each connection point. This suggests that the contribution of an individual PV customer and any associated avoided TUoS payments is likely to be less than the cost to network businesses of administering the payments.

Magnitude of the changes in peak demand

Consistent with the peak time of day analysis above, few of Energex's domestic zone substations experienced an overall reduction in peak demand due to solar of greater than 0.25 MW in 2014–15 (Figure 84).

[318] Frontier Economics 2016, p. 10.

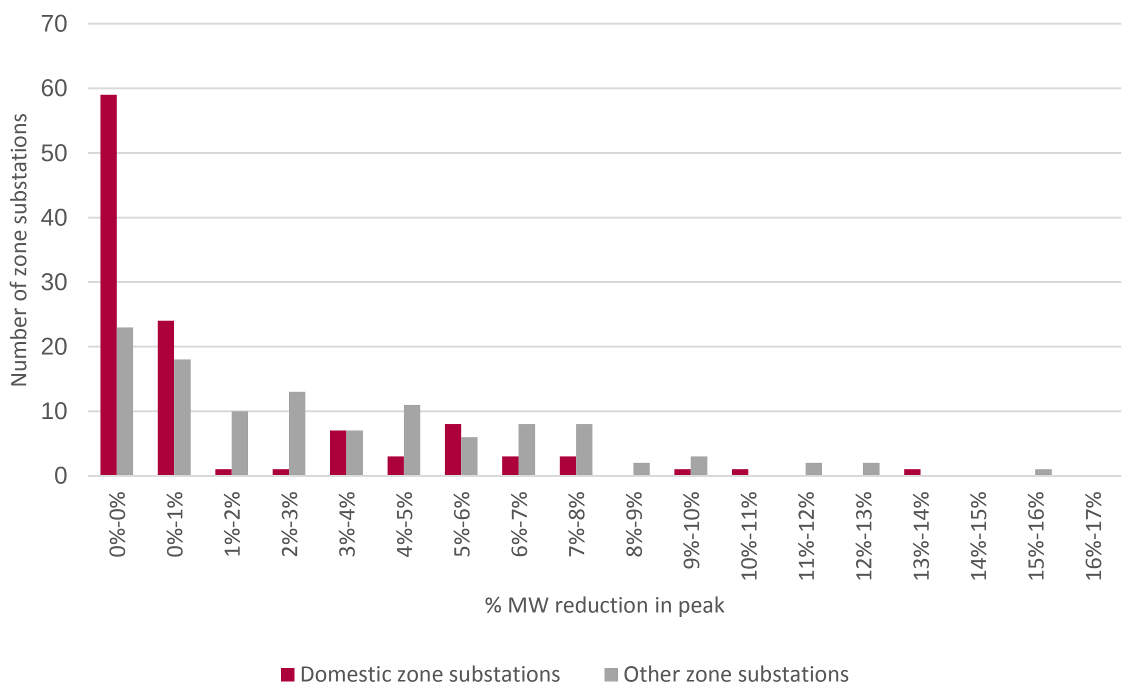
Figure 84: Reduction in peak for Energex zone substations (MW), 2014–15



Source: Energex 2015c; Energex data; QPC calculations.

Expressed as a proportion of peak demand rather than as megawatts, few Energex domestic zone substations experienced a reduction in peak demand in 2014–15 of greater than 1 per cent of the peak (Figure 85).

Figure 85: Reduction in peak for Energex zone substations (proportion of peak), 2014–15

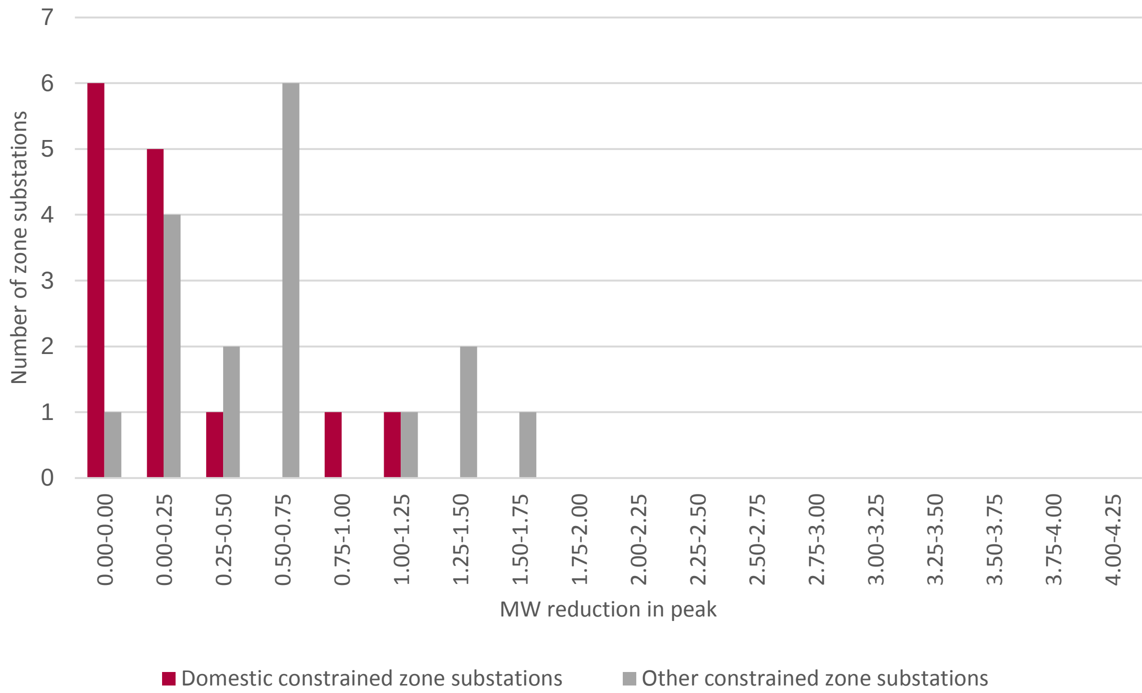


Source: Energex 2015c; Energex data; QPC calculations.

Eleven of the 14 Energex domestic zone substations identified as constrained have a peak reduction of less than 0.25 MW (Figure 86) —a peak reduction of less than one per cent (Figure 87).

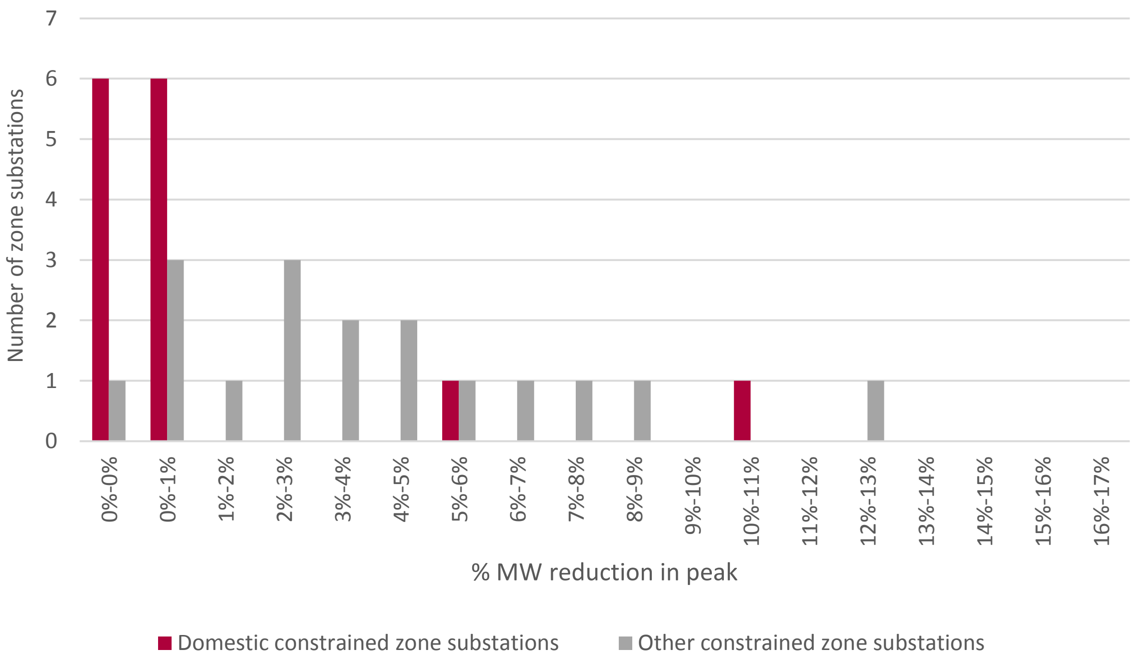
As industrial, mixed industrial and mixed domestic zone substations generally peak earlier in the day, the magnitude of the peak reduction is greater. For example, six of the substations have a reduction in peak of between 0.50 and 0.75 MW.

Figure 86: Reduction in peak for Energex constrained zone substations (MW), 2014–15



Notes: Constrained substations identified based on sections 4.1 and 4.2 of DAPR 2015.
Source: Energex 2015c; Energex data; QPC calculations.

Figure 87: Reduction in peak for Energex constrained zone substations (proportion of peak), 2014–15

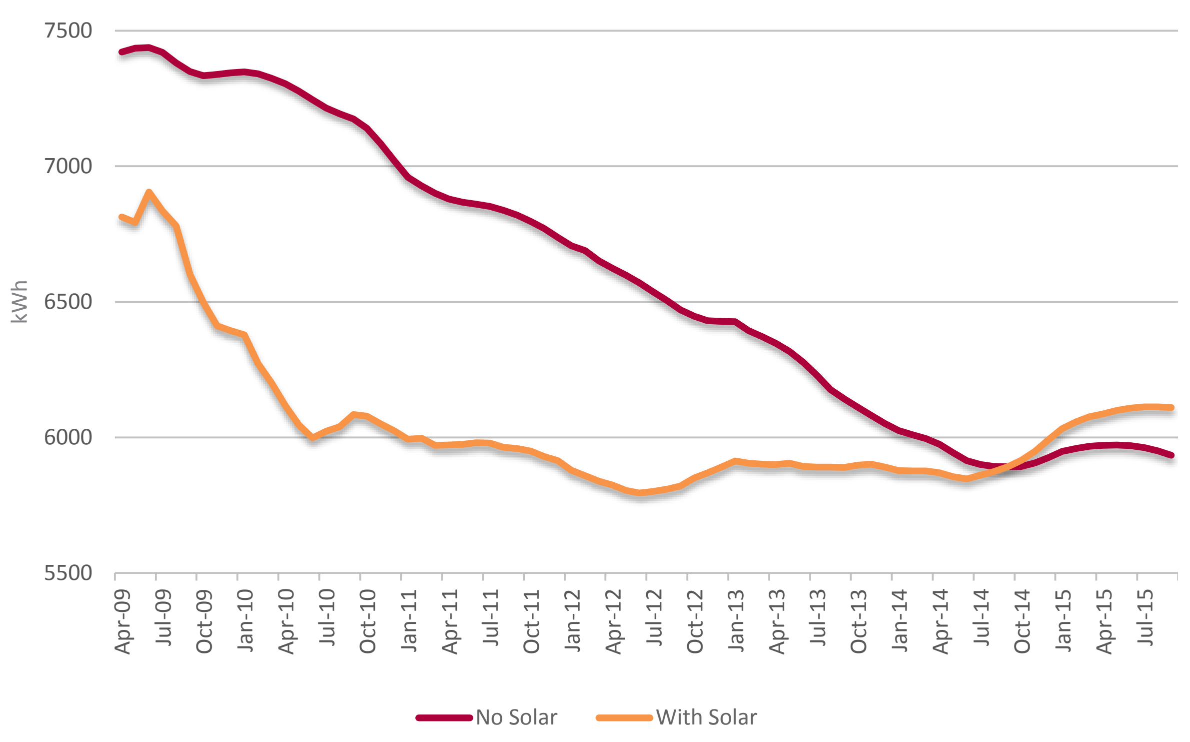


Source: Energex 2015c; Energex data; QPC calculations.

Since 2009, there has been a decline in average residential consumption for both solar and non-solar households. The rate of decline has been greater for non-solar households falling roughly 20 per cent between June 2009 and June 2015, compared to 11 per cent for solar households (Figure 88). From mid–2014, Energex data indicates that solar households use more electricity than non-solar households.

A range of factors may be driving the trends, including the responsiveness of solar and non-solar households to electricity prices, differences in average consumption volumes, trends in disposable incomes, improvements in appliance efficiency, and perceptions of solar households as to the true costs of consumption of electricity produced by their PV systems.

Figure 88: Average annual residential consumption (kWh)



Source: Energex data.

To examine the possible impacts of declining average consumption on the load profile of a zone substation and peak demand, it is assumed for the Jindalee zone substation that:

- the reduction in average consumption on Energex's network was also observed for the substation; and
- the reduction occurred evenly across the load profile. The shape of the load profile for a zone substation in the absence of the decline since 2009 is not observed or metered (that is, whether the decline occurred more at certain times during the day/night or proportionally across time periods).

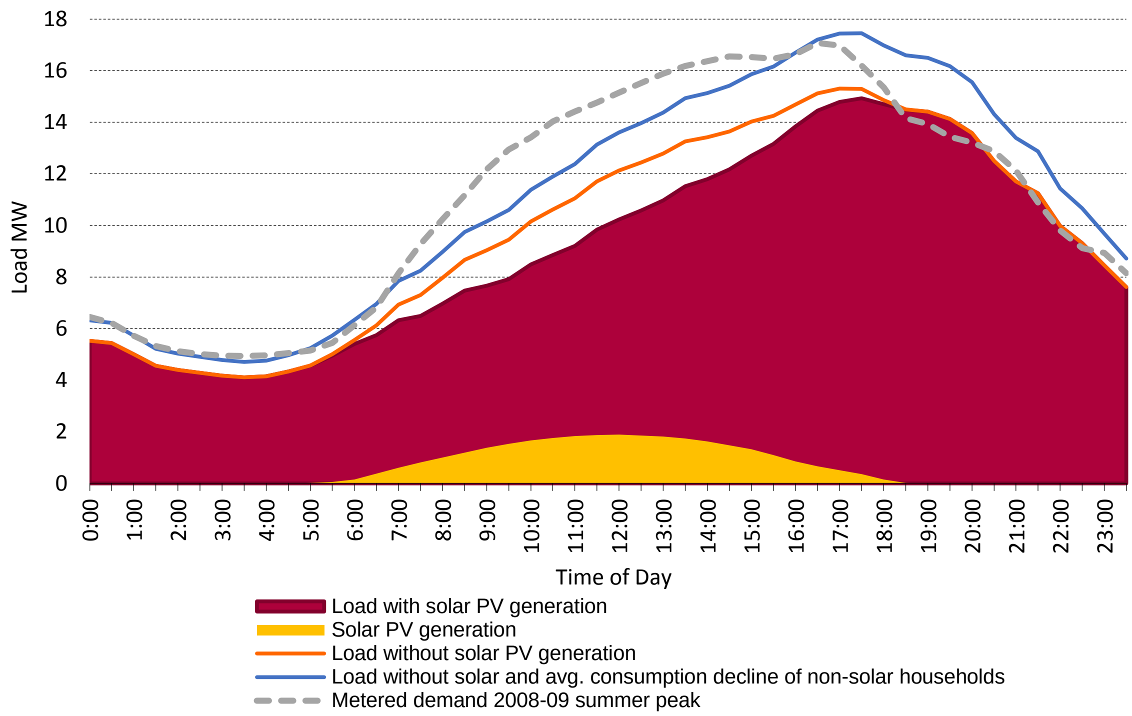
Therefore:

- each point on the load profile 'Load without solar PV generation' is increased by 20 per cent adjusted for the share of non-solar households in substation demand to derive a load profile which excludes both the effects of solar generation and the decline in average consumption of non-solar households; and
- no adjustment is made for the decline in average consumption of solar households.

Given these assumptions, the decline in the peak driven by the decline in the average consumption of non-solar households is significantly greater than the decline in the peak due to solar PV generation (Figure 89). In 2014–15, solar PV reduced the peak on the Jindalee substation by about 2.4 per cent. If, or to the extent that, non-solar households have reduced their consumption at times other than the peak, then the impact on the peak is overstated.

A comparison of the 2014–15 adjusted load profile against metered demand on the zone substation for the summer peak of 2008–09 shows that maximum demands are similar, but there has been an overall shift in the load profile to the right (to later in the day).

Figure 89: Illustration of reduction in peak due to decline in average non-solar household consumption, Jindalee zone substation, 2014–15



Notes: The decline in average consumption of non-solar households is assumed to affect the load profile proportionally across the 24 hour period.

Source: Energex data; QPC calculations.

This scenario illustrates both the challenge of isolating the impact of solar PV and the imprudence of solely concentrating on solar PV. If there were grounds to pay solar PV owners for reducing peak demand, then there would be grounds for paying non-solar households as well.

However, in both cases a network saving from a peak reduction can only occur if there is a capacity constraint on a substation or distribution feeder leading to investment deferral. In the case of the Jindalee zone substation, the substation is not capacity constrained (NCC rating of 35.6 MVA compared to forecast 50 PoE load of 15.0 (MVA) for summer 2015–16).

Where peak demand is lower than the forecast used to set Energex's allowable revenue, at the end of the period, the lower augmentation spend is reflected in the regulatory asset base (RAB), resulting in a lower starting point for calculation of the return 'on' and 'of' assets. To the extent demand forecasts are lower at the time of setting the revenue, this will be reflected in lower forecast augmentation expenditure.

Both solar PV and declines in consumption can reduce peak demands. However, at current solar penetration rates, any deferral benefits driven by average consumption reductions result overwhelmingly from the consumption choices of non-solar households (there are about three non-solar households for every solar household).

Forecast error, future regulatory periods and the impacts of solar

Forecasts of key variables used in identifying network constraints, such as economic growth, are subject to a significant degree of error. Network constraints for the current regulatory period were identified based on forecast weak economic growth to 2019–20. Were growth to accelerate to long-run averages or stronger, then the number of network assets subject to capacity constraints would likely increase. This would increase the number of instances where solar may result in a deferral benefit through reducing maximum demand, assuming that the higher growth also occurred on network assets with daytime peaks.

Key drivers of maximum demand may also be significantly different in the next regulatory period. Those conditions might produce fewer or more numerous network capacity constraints. Technological change, such as the uptake of battery storage solutions, will also influence the potential of solar to provide a peak reduction benefit.

Regulatory/security standards may also be different in a future regulatory period, which will influence the impacts of solar PV. In addition, solar penetration rates will be higher by the time of the next regulatory period, and this is posing, and will continue to pose, challenges for networks in mitigating some of the negative impacts of solar on networks.

Impacts on network productivity and costs

Capital productivity and 'hollowing-out'

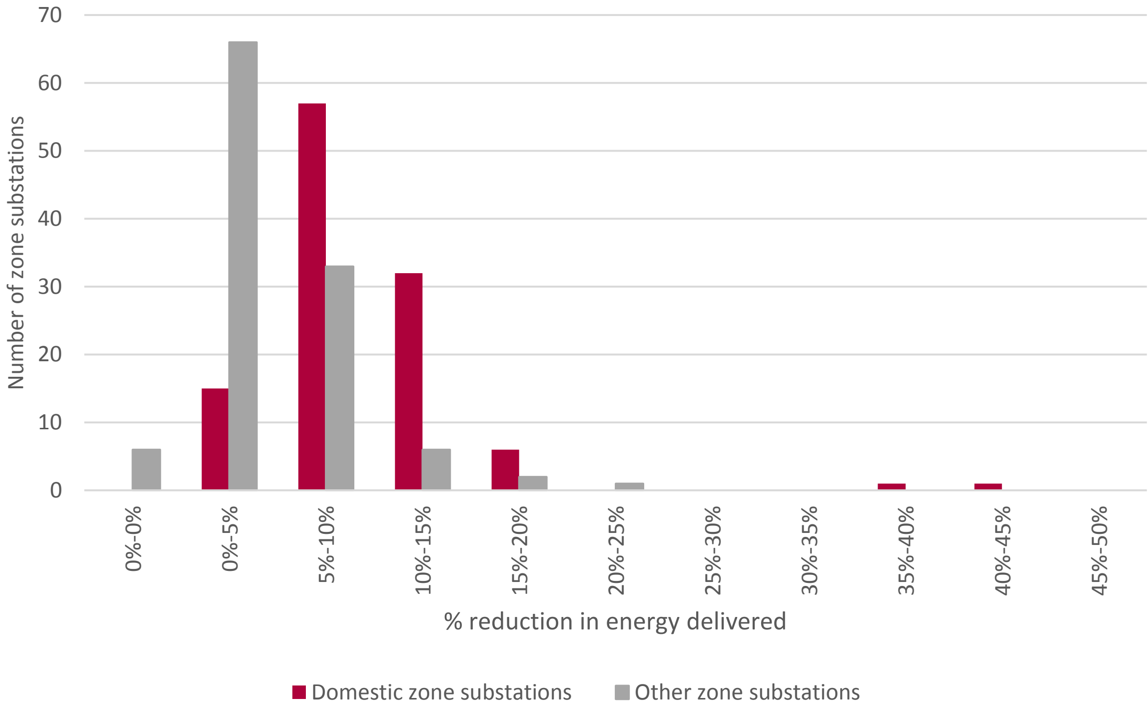
In industries that are highly capital-intensive and have peak constraints, a financial benefit to the supplier is only obtained where the customer's changed behaviour reduces the peak and does not reduce total consumption (and revenues to the supplier) by more than the amount of the cost savings from the marginal deferral of investment.

Reductions in energy delivered over the network reduce network capital productivity. Both solar PV and the decline in average consumption would have reduced the utilisation of network assets, and the contribution of the assets to industry output (value added). Given relatively few network constraints and the shift in peaks to early evening, these effects likely swamp any positive impacts from investment deferral.

While for most zone substations there has been little impact on zone substation peak demand, there has been a significant reduction in average utilisation of those network assets. Most domestic zone substations experienced a reduction in load between 5 and 15 per cent (89 out of 112 zone substations) (Figure 90). Other zone substations include industrial, mixed industrial and mixed domestic substations. Out of 114 other zone substations, 33 experienced a reduction in load between 5 and 10 per cent, and 66 experienced a reduction between 0 and 5 per cent.

The loads on substations are an aggregate of the loads on the distribution feeders which feed the substation. Case studies of distribution feeders show the same 'hollowing-out' of load profiles. 'Hollowing-out' reduces the efficiency of existing network assets. Given the assets are in place, and given that changes in the average utilisation of the assets does not drive costs, reductions in utilisation reduce the contribution of the assets to industry output.

Figure 90: Reduction in energy delivered through Energex zone substations, 2014–15

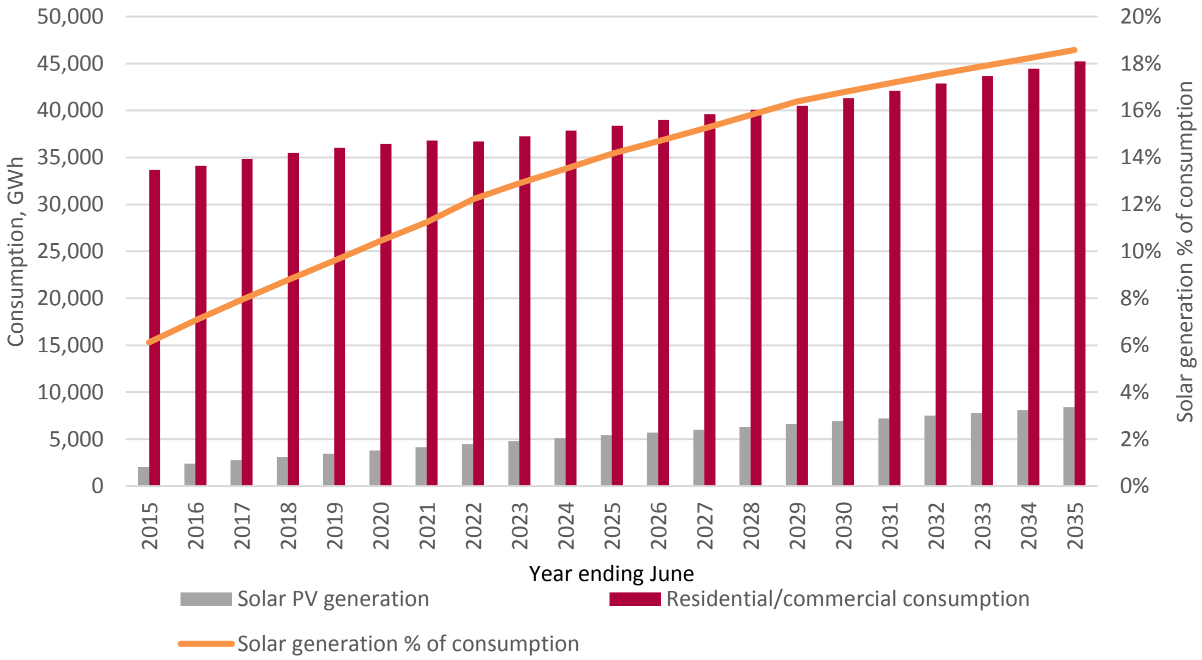


Notes: Reduction in energy delivered is for the 24 hour period of the identified peak day.
Source: Energex 2015c; Energex data; QPC calculations.

Solar PV generation is a small fraction of Queensland electricity consumption

In 2014–15, solar PV is estimated to have generated 2063 GWh of electricity, or about 6.1 per cent of the volume of electricity consumed by residential and commercial customers in Queensland (Figure 91). This limits the impacts of solar on electricity networks, both positive and negative impacts. However, as solar penetration rises over time, there is increasing scope for impacts on networks. Nevertheless, aggregate data can mask network cost drivers as solar penetration rates at the local level are already high enough to be having significant impacts on some zone substations and distribution feeders.

Figure 91: Solar PV generation compared to Queensland electricity consumption



Notes: Data based on base case modelling results. Consumption data includes both Queensland NEM customers and Mt. Isa customers. Consumption data excludes industrial customers.
Source: ACIL Allen 2015.

Solar PV can cause capital expenditure to occur as well as delay it

An evaluation of the potential deferral benefits of solar PV has to take into account offsetting increases in operating and capital expenditures that result from solar PV driving fault and voltage issues on the network.

Queensland has one of the highest penetrations of solar PV in the world. This has presented a number of challenges in terms of the safe and efficient management of the network. These challenges include maintaining electricity supply quality for customers and managing the effects of reverse power flows; both of which increase the cost of providing network services. As the proportion of solar PV increases on the distribution network, and the proportion of synchronous and asynchronous machines reduces on the transmission grid, this can lead to instability (load shedding) in the transmission grid during fault conditions leading to reduction in the security of the overall grid.

The increasing levels of reverse power flows mean that more sophisticated transformer and LV circuit monitoring is required. As a result, over the 2015–20 regulatory period, Energex expects to incur approximately $24 million ($2014–15, direct) in capital expenditure ($14 million for monitoring works and $10 million in remediation works) related to power quality issues caused by solar PV (Table 50).

Table 50: Capital expenditure related to solar PV, $ million 2014–15 real

Power quality capital expenditure	*2015–16*	*2016–17*	*2017–18*	*2018–19*	*2019–20*	*Total*
Solar PV related	3.7	3.1	3.1	7.0	7.0	24.0
Power quality CAPEX	3.9	3.3	3.3	7.4	7.4	25.3

Notes: Energex did not capture capital expenditure directly related to solar in the previous regulatory period as it was an emerging network issue.

Source: AER 2015a; Energex return to the QPC information request.

As part of Ergon Energy's submission to the AER for the regulatory control period, Ergon Energy analysed capital expenditure requirements for 63,732 distribution transformers in its network of feeders. Between 4676 and 8216 distribution transformers (with the range depending on low and high forecast solar PV uptake scenarios) were identified as likely needing augmentation expenditure to address solar PV (inverter energy system) attributed issues. Augmentation works separately identified to address capacity constraint issues were estimated to reduce required solar PV driven expenditure needs by between 359 and 553 distribution transformers.[319]

In its final determination for the current regulatory period for Ergon Energy, the AER identified $26.4 million (direct) in necessary capital expenditure to address issues caused by micro embedded generator units (overwhelmingly solar PV systems).[320]

Solar PV increases the need for network operating expenditure

Quality of supply enquiries occur when a customer contacts a DNSP with a concern that their supply may not be meeting standards. Quality of supply issues are categorised by Ergon Energy as: on initial contact; low supply voltage; voltage dips; voltage swell; voltage spike; wave form distortion or unbalance; TV or radio interference or unbalance and noise from appliances.

Solar is having negative impacts on reliability on some feeders. Distributors expect this issue to become a more important driver of costs as penetration levels rise (discussed in Chapter 6). In its 2015–20 regulatory proposal submission to the AER, Ergon Energy (Network) provided data showing that solar related quality of supply complaints had grown strongly over the period 2010–11 to 2014–15 (Table 51).

Table 51: Ergon Energy quality of supply complaints

Year	*Quality of supply complaints*	*Non-solar complaints*	*Solar issue complaints*	*Solar complaints as % of total quality of supply complaints*
2010–11	950	879	71	7.5%
2011–12	975	828	147	15.1%
2012–13	1398	806	592	42.3%
2013–14	817	510	307	37.6%
2014–15 (estimate)	1260	750	510	40.5%

Source: Ergon Energy Corporation (Network) 2015d, p. 114.

Energex indicated that changing network configurations, increasing customer peak demands, and the prospect of growth in plug-in electric vehicles are all driving the need to devote resources to address power quality issues, particularly on the low voltage network. However, a more significant driver of power quality problems has been the adoption of substantial solar PV:

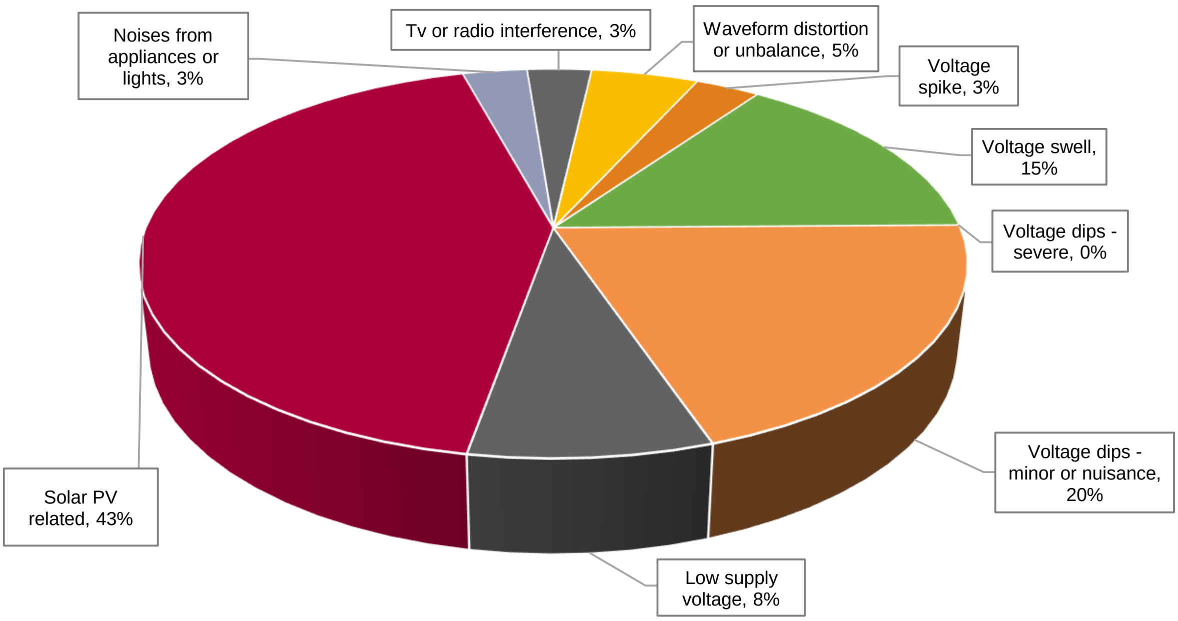
> *The forecast increase in the solar PV connected inverter capacity on the network in the next five years will rapidly increase the number of distribution transformer areas expected to have power quality problems.*[321]
>
> *The key driver for the power quality strategy is responding to network voltage impacts arising from the high penetration of Solar PV. Energex has obligations to ensure that such inverter energy systems do not cause a material degradation in the power quality to other network users and do not adversely affect operation of the*

[319] Ergon Energy n.d., pp. 24–25, unpublished.
[320] Ergon Energy return to the QPC information request.
[321] Energex 2015b, p. 136.

distribution network. This will require the network to be adapted over time to be able to continue to deliver a safe and reliable service with acceptable power quality.[322]

Similar to Ergon Energy, a significant proportion of power quality enquiries to Energex are related to solar PV (Figure 92). In the 12 months to March 2014, 43 per cent of enquiries received were classified as solar-related power quality problems.

Figure 92: Power quality voltage enquiries classified by symptom, 10 July 2013 – 14 March 2014



Source: Energex 2014e, p. 10.

Energex's regulatory proposal to the AER included a program targeted at monitoring and managing power quality issues and in particular the issues resulting from the high penetration of solar PV connected to the LV network.

Operating expenditure driven by solar PV issues was forecast to amount to $11 million over the regulatory period (Table 52). The expenditure was expected to be incurred for voltage investigations and re-balancing LV transformer circuits.

Table 52: Energex operating expenditure directly related to solar PV, $ million 2014–15 real

	2015–16	*2016–17*	*2017–18*	*2018–19*	*2019–20*	*Total*
Solar PV related OPEX	2.0	2.1	2.2	2.3	2.4	11.0

Notes: Energex did not capture OPEX directly related to solar in the prior regulatory period as it was an emerging network issue. Source: Energex 2014e.

Similarly, Ergon Energy forecasts $12 million in operating expenditure (excluding overheads) to address solar issues during the regulatory period.

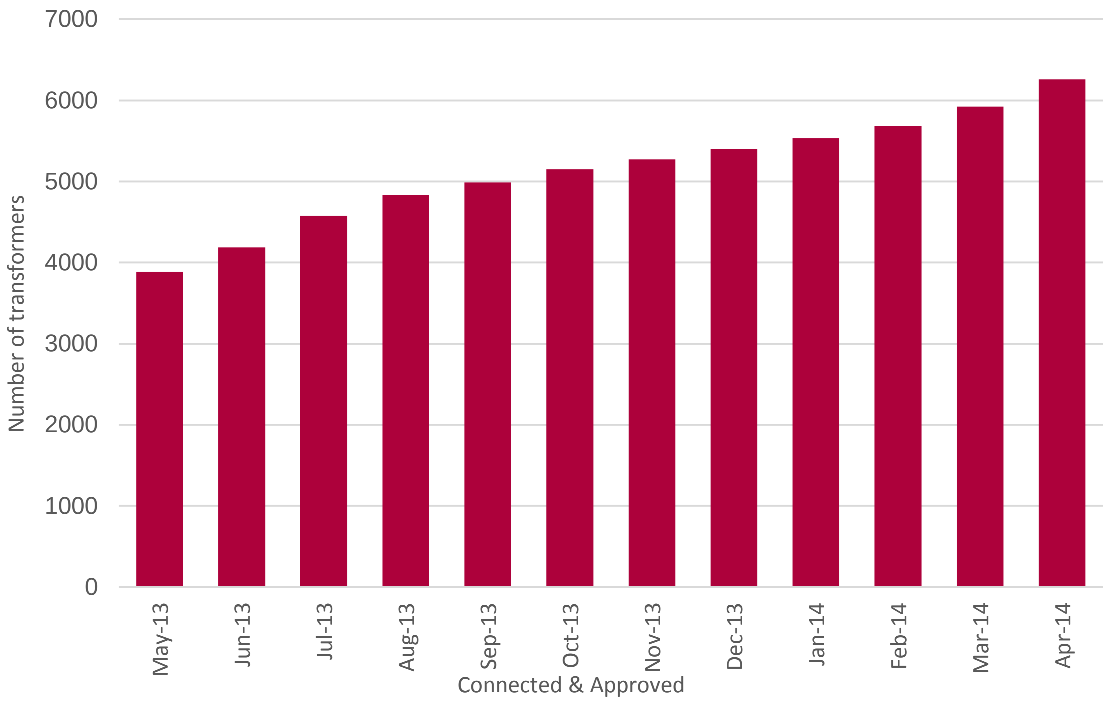
Energex measures solar PV penetration based on the ratio of the kilowatts of installed inverter capacity to the transformer capacity supplying the low voltage areas in question. A small number of transformers have solar PV equipment installed that exceeds the transformer rating, leading to a greater than 100 per cent penetration rate.

[322] Energex 2014e, pp. 10–11.

Saturation studies indicate that voltage issues can occur once PV penetration exceeds 25 per cent, as it becomes more likely for power flows to reverse during lighter load period in the middle of the day, impacting the ability to manage voltage within statutory limits.

The number of transformers with high solar PV penetration connected or approved has been increasing rapidly and accounts for roughly 13 per cent of all Energex transformers as at April 2014 (Figure 93).

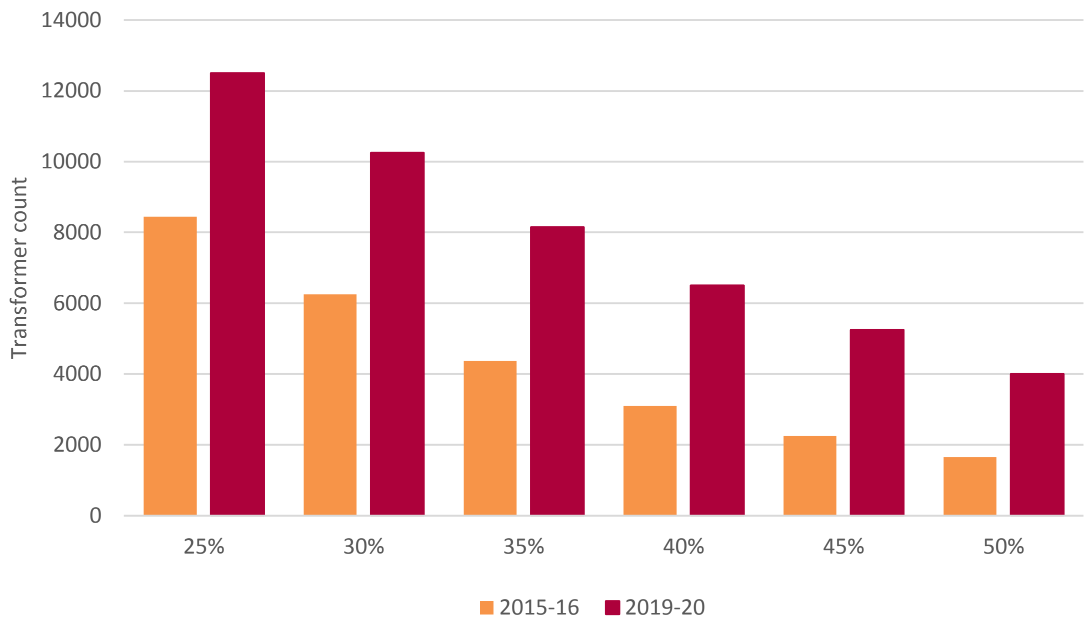
Figure 93: Distribution transformers with solar PV penetration > 25% of Nameplate rating



Source: Energex 2014e, p. 14 of Appendix 29.

Given projected continued growth in solar installations at a rate greater than the rate of new dwellings construction, Energex expected around 8000 transformers to exceed 25 per cent penetration by 2015–16, and expects in excess of 12,000 by 2019–20 (Figure 94).

Figure 94: Forecast number of transformers exceeding solar PV thresholds



Source: Energex 2014f.

Energex has experienced a similar increase in the number of 11 kV feeders with excess of 1 MW of connected solar PV. Energex projections indicate that, given the continued growth in solar PV expected over the 2015–20 period, areas with 25 per cent penetration are likely to reach the 40 per cent threshold by 2020, and areas with 15 per cent penetration are likely to reach penetration levels of 25 per cent.

There are a range of measures for addressing the impacts of high solar PV penetration rates which vary according to the level of penetration (Table 53). For example, in relation to distribution feeders, Ergon Energy notes:

> *Distribution feeder capacity problems can be solved in a number of ways, depending on the local characteristics of the distribution feeder. These solutions include: re-rating / replacing the underground exit cable or overhead feeder, transferring existing load to adjacent feeders if capacity is available, creating new feeders and transferring existing load, demand management initiatives that reduce customer loading (these may include encouraging customers to shift loads to control tariffs such as T31 and T33, to install energy efficient appliances, to install 'peak smart' devices etc.) and installing embedded generation and/or storage to 'peak lop'.*[323]

Energex considers that the cost of remedial work generally rises as the solar PV penetration level rises. In practice, the ability to absorb solar PV generation without issue is very dependent on how loaded a network is compared to design limits and how long an LV circuit is from the transformer terminal.[324]

[323] Ergon Energy 2015, DAPR, p. 80.
[324] Energex 2014, Energex Regulatory Proposal, Appendix 29: Power quality strategic plan 2015–20, Brisbane, p. 16, October.

Table 53: Typical costs of network solution responses to high solar PV penetration levels

Solar PV penetration level	*Network solution*	*Estimated unit rate ($)*	*Note*
From 30% to 70%	1. Balance of PV load	$2670	Balancing the solar PV generation is an effective option when there are large single phase solar PV systems on the smaller distribution transformers (less than 20 customers). Balancing is less effective on the larger distribution transformers (where there are up to 100 customers) and the loads are better balanced.
	2. Change transformer tap	$861	A change in transformer tap will reduce the voltage by 6 V (2.5%) — this is the main option for addressing high voltage but may not be possible if the customer voltages fall below the regulated limit of 225.4 V at peak load times. Generally only one tap-change increment can be accommodated without compromising the voltage to other customers.
From 40% to 100%	3. Combination of 1 and 2 above		
	4. Upgrade transformer	$15,000	An upgraded transformer will allow the opportunity to re-set the taps (by 6 V) and allow higher penetrations of solar PV. This option may not be possible if the pole is not suitable for the additional mechanical loading.
	5. New transformer	$62,261	A new transformer is generally required where the high voltage is caused by long lengths of LV, typically in excess of 600 metres — this may be all Energex LV conductors or part Energex and part consumer mains. The cost for a new transformer installation can be considerable if the 11 kV network has to be extended a long distance.
	6. Re-conductor mains	$123,184	Where there is smaller aged conductors (e.g. 7/.080 copper) re-conductoring is an option to reduce voltage rise/drop and maintain LV within regulated limits. Modelling indicates that re-conductoring 7/.080 with LVABC can halve the voltage rise.
From 100% to 200%	7. Combination of 1 to 6 above		
	8. On load tap transformer		Some of the newer technologies (e.g. on load tap changer) are expected to cost more than an upgraded transformer, but less than the installation of a new transformer, but others (e.g. STATCOM) is expected to be at a similar cost to a new transformer. The STATCOM does have other advantages as it can offset peak load with the use of the battery storage.
	9. LV regulator		
	10. Regformer		
	11. Statcom		

Source: Energex 2015b p. 138; Energex return to the QPC information request.

Summary

Forecasts of peak demand are a critical input to the process of identifying network constraints. DNSPs develop forecasts from both a bottom-up or asset by asset approach, and also a macro or systemwide approach. Bottom-up forecasts are closely linked to DNSP responses to identified constraints, including responses which involve additional operating expenditure and capital investment.

Bottom-up forecasting procedures take account of solar when analysing historical relationships between peak demand and the determinants of peak demand. In developing forecasts, Ergon Energy forecasting procedures effectively negative the impact of solar, due to its intermittency, so that solar does not reduce forecast peak demand and delay the identification of a capacity constraint. For Energex, where the conditions are such that solar output reduces peak demand for a network asset, solar is taken into account in a lower peak demand forecast, which in turn makes it less likely that a network constraint will be identified.

However, for the current regulatory period covering 2015–16 to 2019–20, Energex's network is forecast to have relatively few limitations, particularly capacity related. Key drivers have primarily been non-solar related factors, such as subdued economic growth, changes in regulated security standards and prior investments.

The scope of network assets which have the right set of conditions for a potential deferral benefit will only be a small proportion of network assets during any one period:

- Forecasting procedures will typically identify a small proportion of assets as having a limitation;
- Only a proportion of the limitations will be capacity related; and
- Of capacity constrained assets, a minority of assets will have daytime peaks, particularly where substations and feeders serve domestic customers.

For example, of almost 2100 11kV distribution feeders in Energex's network:

- only 11 feeders were identified in its DAPR as having a limitation; and
- only two of these were capacity related.

Another 11 feeders were being monitored as emerging limitations. Six of these feeders have night-time peaks with no potential for solar to reduce peak demand. For the remaining 5 feeders with daytime peaks, analysis indicates that the deferral potential of installed solar capacity is: 2 years for one feeder; 1 year for two feeders; and less than a year for the other 2 feeders.

Solar has had little impact on network capacity constraints because the time of day of the peak for most network assets is either when solar is generating at low output or is not generating at all. For example, a large proportion of both Energex's and Ergon Energy's zone substations peak after 6 pm.

Solar has also provided little delay benefit to networks because many assets with daytime peaks are not forecast to face capacity constraints over the current regulatory period.

On the other hand, increasing solar penetration rates are driving network issues that require increasing operating expenditure and, in some cases, capital investment. Approved capital expenditure and operating expenditure directly related to solar over the regulatory period amounts to more than $73 million (in real $2014–15).

APPENDIX H: SOLAR PV AND ELECTRICITY SUPPLY PRODUCTIVITY

The productivity performance of the electricity supply industry and Distribution Network Service Providers (DNSPs) is examined in this appendix to provide a basis or reference point for understanding some of the economic impacts of solar investment.

Productivity performance of the electricity supply industry

The productivity performance of an economy is important because it is the key driver of improvements in living standards over the long term:

> *Productivity performance has been the main source of Australia's long-term economic growth, business competitiveness and real per capita income growth. It is an important determinant of a country's living standards and wellbeing.*[325]

Productivity can be measured at the whole-of-economy level, at the industry level, and at the individual firm level. For an industry, productivity growth occurs where the net effect of the productivity performance of all the businesses in the industry results in more output being produced for the same level of inputs consumed in production, and/or the same level of output produced, but fewer resources consumed in its production.

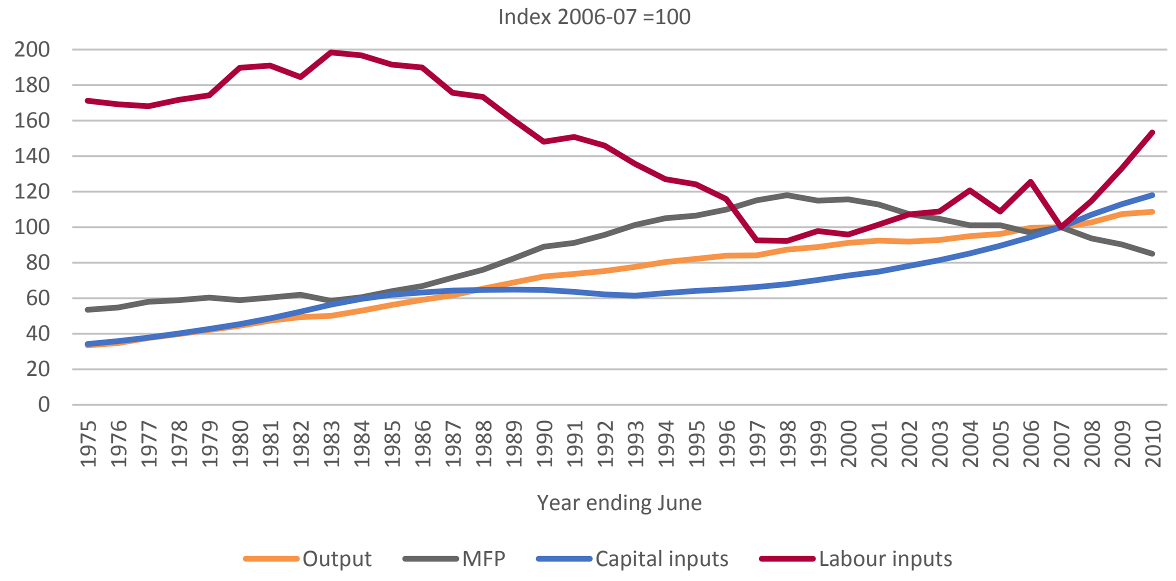
In competitive markets, productivity growth occurs through the growth of efficient firms, the decline and/or exit of inefficient firms, and the entry of new firms. In markets subject to high levels of economic regulation, such as electricity transmission and distribution networks, the reallocation effect between firms is by and large non-existent and productivity growth occurs when regulated entities improve their productive efficiency (the ratio of outputs produced to inputs used).

The Australian Bureau of Statistics (ABS) publishes productivity data at the ANZSIC industry divisional level[326], including for electricity, gas, water and wastewater (EGWW) combined. To focus more closely on the productivity performance of subindustries, including the electricity supply industry, Topp and Kulys[327] constructed estimates from unpublished ABS data. The electricity supply industry includes generation, transmission, distribution and retailing businesses.

Multifactor productivity (MFP) in the electricity supply industry peaked in 1997–98 and then declined until 2009–10 (Figure 95).[328] MFP is a ratio of output to the inputs used in its production. MFP growth is a measure of the rate of change of the outputs less the rate of growth in inputs. If outputs are increasing faster than inputs, then productivity growth is positive, indicating improvements in overall relative efficiency. MFP is a measure of the ability of the businesses operating in the industry to transform inputs into outputs valued by consumers.

[325] PC 2015, p. 5.
[326] ANZSIC is the Australian and New Zealand Standard Industrial Classification; ABS 2015c.
[327] Topp & Kulys 2012.
[328] The study constructed estimates of productivity focused on the electricity supply industry defined to include generation, transmission, distribution and retailing businesses and electricity market operators. ABS published estimates include the electricity industry combined with other industries, such as, the gas, water and wastewater industries.

Figure 95: Electricity supply MFP, outputs and inputs for 1974–75 to 2009–10



Source: Topp & Kulys 2012.

The decline in MFP performance following 1997–98 followed a period of rapid growth (Table 54). Compared to the period 1985–86 to 1997–98, the period to 2009–10 has shown much slower growth in industry outputs (at 1.8 per cent versus 3.3 per cent) combined with much stronger increases in both labour and capital inputs. The net effect is that MFP is estimated to have declined 2.7 per cent per annum over the period 1997–98 to 2009–10.

Table 54: Electricity supply industry changes in MFP by growth phase

Average annual growth rates in each phase (%) and percentage point contributions

	Moderate MFP growth phase (1974–75 to 1985–86)	*Rapid MFP growth phase (1985–86 to 1997–98)*	*Negative MFP growth phase (1997–98 to 2009–10)*	*Full period (1974–75 to 2009–10)*
MFP	**2.0**	**4.9**	**–2.7**	**1.3**
Output	5.3	3.3	1.8	3.4
Labour	1.0	–5.8	4.3	–0.3
Capital	5.8	0.6	4.7	3.6

Source: Reproduced from Topp & Kulys 2012, p. 31.

The main drivers of the change in electricity supply industry productivity performance between the rapid growth phase and the phase starting from 1997–98 were found to be:

> *Around half of the MFP decline in [the electricity supply industry] was due to an increase in the ratio of peak to average electricity demand, which lowered average rates of capacity utilisation. This was largely attributable to rapid growth in household use of air-conditioners.*
>
> *Three other contributors were: cyclical investment in lumpy capital assets, which temporarily increased inputs ahead of growth in output; a shift to greater undergrounding of electricity cabling, which raised costs and the quality of output, but not the volume of measured output; and policy induced shifts away from coal-fired power to higher-cost, but less polluting, sources of new supply.*[329]

[329] Topp & Kulys 2012, p. XIV.

Electricity supply is a capital-intensive industry; therefore investment decisions and the subsequent use of assets have a large influence on industry productivity. The period 1985–86 to 1997–98 featured an increase in the utilisation of existing industry assets. The overhang in generation and network capacity at the beginning of the period allowed an increase in utilisation of capital capacity[330] that contributed to an increase in measured productivity.

The electricity industry needs to ensure that enough supply capacity is available to meet expected peak demand whenever it occurs, not just the average amount of electricity demanded. Hence, growth in peak demand over time, not growth in average demand, determines required supply capacity. The increase in peak demand can be attributed to a range of factors, particularly increased air-conditioning usage, solar PV installation (under premium feed-in tariff schemes) and household appliance usage.

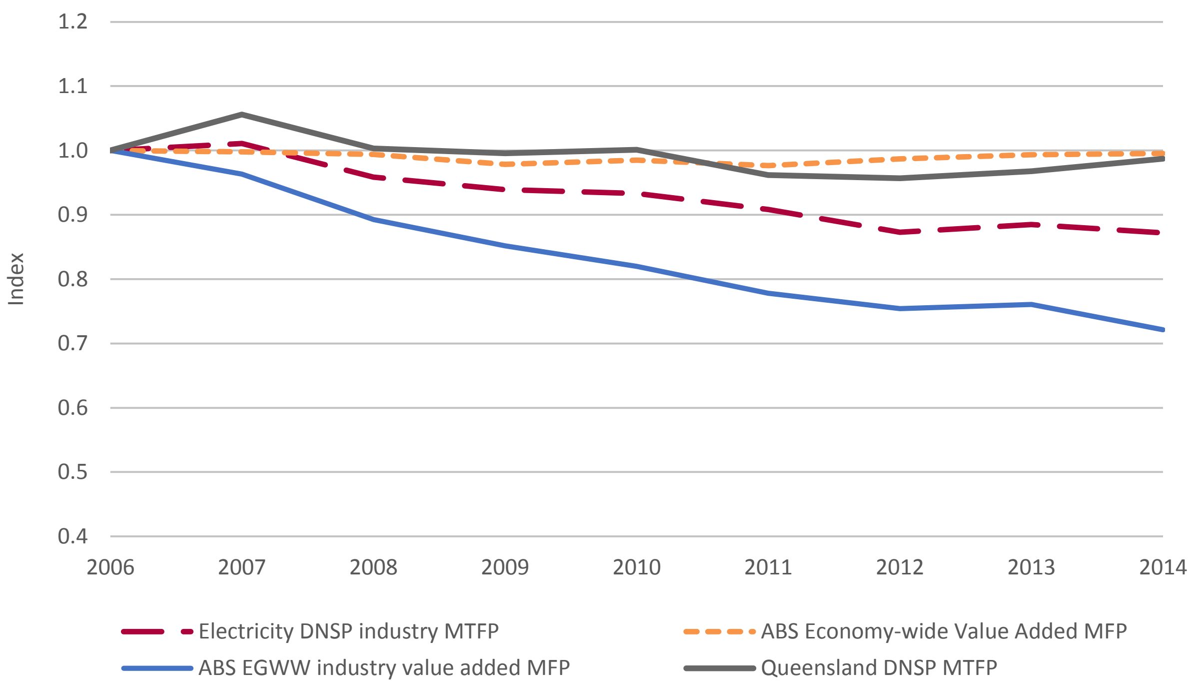
The study also found that changes in generation technologies, with a shift away from coal-fired energy towards higher-cost gas-fired and renewable energy, had reduced industry productivity.

Productivity performance of Queensland's DNSPs

To support its regulatory functions, the AER undertakes economic benchmarking of transmission businesses and DNSPs from information collected directly from the businesses. Thirteen distribution network service providers operating in the National Electricity Market (NEM) are included in the benchmarking exercise, including Energex and Ergon Energy. The most recent data includes the period up to 2014.

While there are differences in the specification of outputs, inputs and productivity between ABS and AER measures, the productivity performance of DNSPs appears to have been worse than economy-wide performance since 2006, and better than productivity growth for EGWW as a whole (Figure 96).

Figure 96: Comparison of DNSP productivity with broader measures for 2006–14

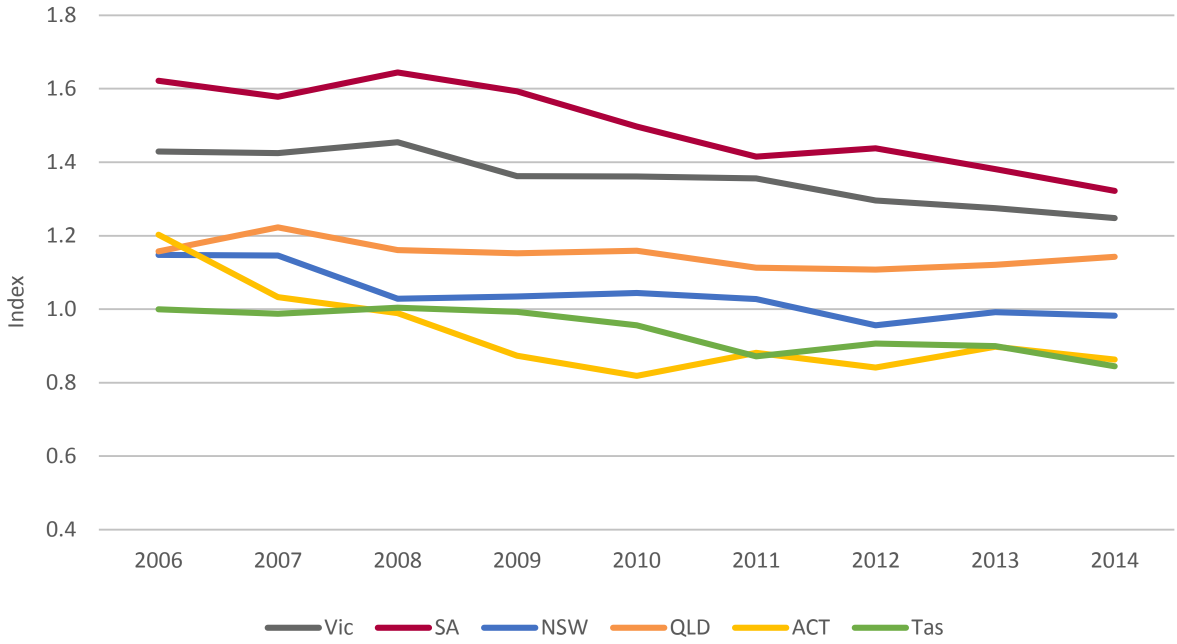


Notes: The ABS measures are based on industry value added which differs from the specification of outputs used by the AER. DNSPs are a sub-sector of the ABS industry division EGWW. The ABS does not construct MFP measures below industry divisional level.
Source: Economic Insights 2015a.

[330] Topp & Kulys 2012, p. XX.

For Queensland DNSPs, gradual improvement from 2012 to 2014 has offset the slow decline experienced in earlier years leading to an overall 'flat' productivity performance (Figure 97). The average annual multilateral total factor productivity (MTFP) growth rate for Queensland DNSPs was –0.16 per cent per annum compared to –2.55 per cent per annum for South Australia and –4.15 per cent per annum for Tasmania.

Figure 97: State-level DNSP multilateral total factor productivity indexes for 2006–14



Source: Economic Insights 2015b.

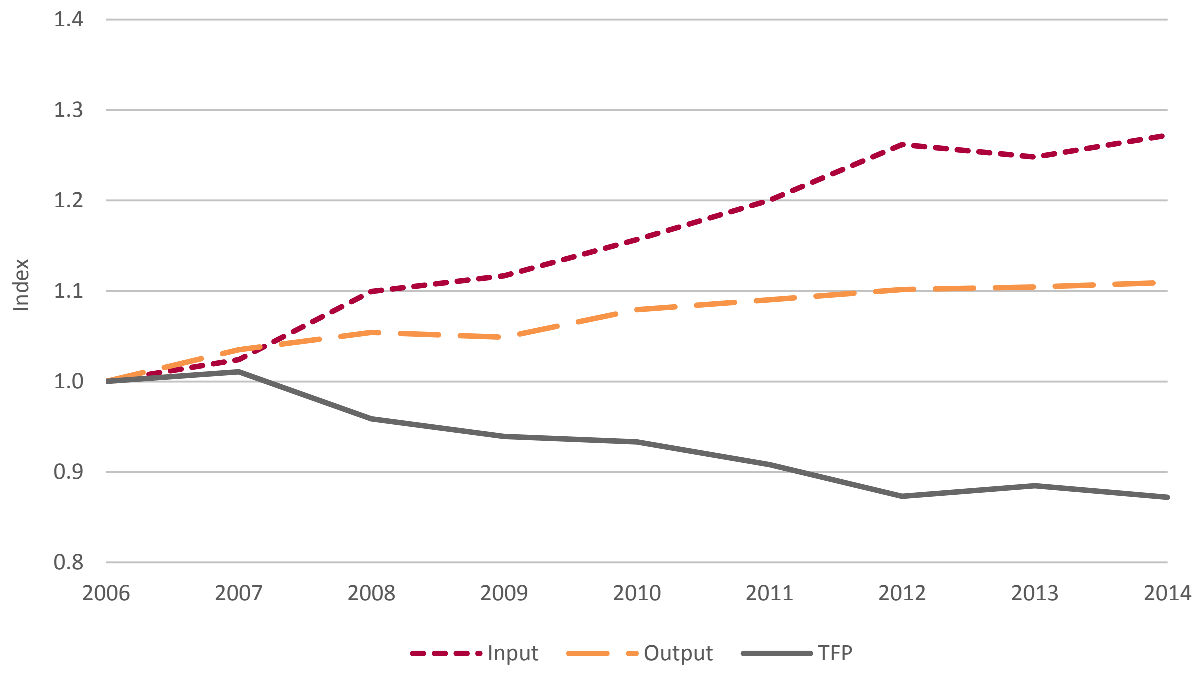
For DNSPs operating in the NEM, inputs have been rising faster than outputs resulting in declining productivity (Figure 98). The AER noted that:

> *Productivity is declining because the resources used to maintain, replace and augment the networks are increasing at a greater rate than the demand for electricity network services (measured in terms of increases in customer numbers, line length, energy, and maximum demand)…For the majority of DNSPs, the declining productivity trend has continued in the twelve months between 2013 and 2014. However, some DNSPs have improved their productivity in recent years, including Energex, Ergon Energy and Essential Energy.*[331]

The average annual growth rate of inputs was 3.0 per cent per annum, while outputs grew at 1.3 per cent per annum.

[331] AER 2015a, p. vi.

Figure 98: Growth in DNSPs inputs and outputs for 2006–14



Note: Index with 2006 set equal to 1.0.

Source: AER 2015c, p. 7.

The AER noted three broad drivers of declining DNSP productivity across the NEM:

- Most outputs have increased moderately or remained relatively flat.
- Jurisdictional regulatory requirements have required some DNSPs to spend more resources without a corresponding increase in outputs.
- Some DNSPs are not using their resources as efficiently as other DNSPs.

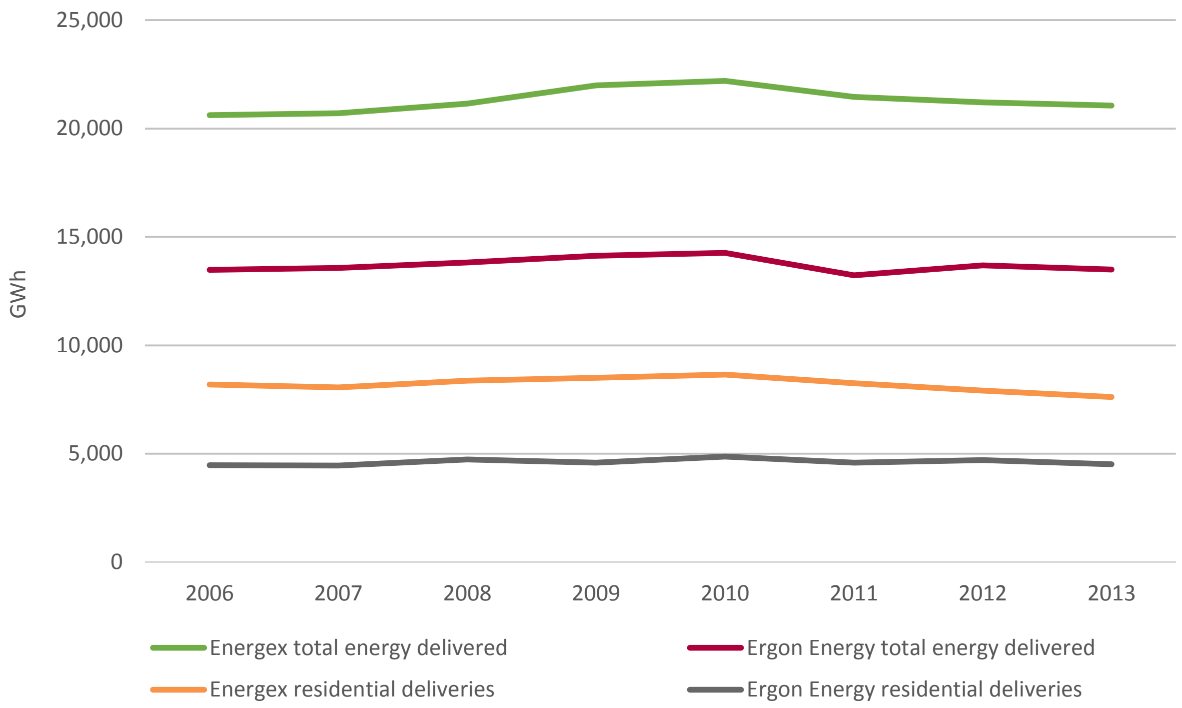
Two examples of jurisdictional obligations increasing inputs during the period are the bushfire mitigation requirements in Victoria — following the recommendations of the 2009 Victorian Bushfires Royal Commission (VBRC) — and the Ministerial reliability requirements in NSW. In both cases, significant asset replacement and upgrades were required. Following the VBRC inquiry, for example, certain overhead lines were deemed unsafe and the DNSPs were required to replace them with safer types of line. This resulted in increased expenditure on assets (an input) but no increase in line length (an output). Similarly, the VBRC requirements also resulted in increased operating expenditure by DNSPs for vegetation clearance purposes, with no change in output.[332] The requirements may or may not have provided sufficient benefits 'outside the industry' to justify their costs.

Outputs

Growth in the volume of energy delivered by Energex and Ergon Energy (Network) has remained flat since 2006 (Figure 99). A number of factors account for slow or no growth including: sustained and sluggish economic growth; energy efficiency schemes; and growth in solar PV generation which reduces demand for electricity from the grid.

[332] AER 2015a, p. 8.

Figure 99: Volume of energy deliveries for 2006–14 (GWh)



Source: Ergon Energy Corporation 2015c; Energex 2015d.

In addition to energy throughput, the AER's specification of the output index includes measures of:

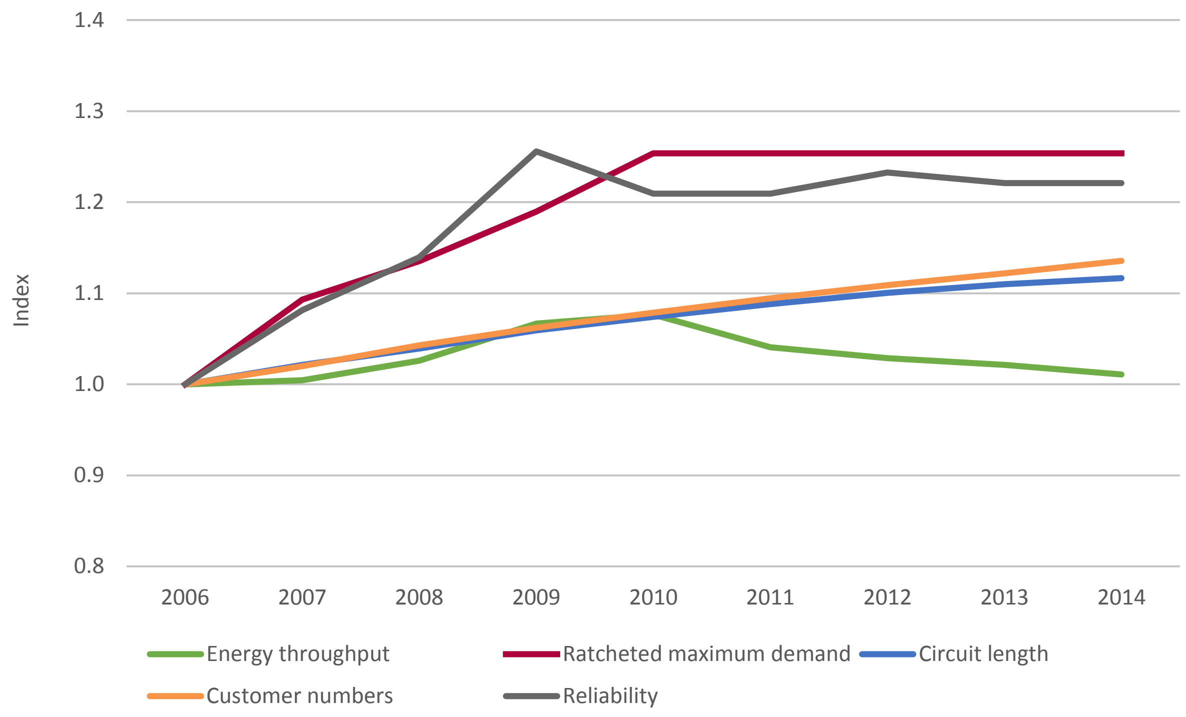
- *Ratcheted maximum demand*: benchmarking techniques use 'ratcheted' maximum demand as an output rather than observed maximum demand. Ratcheted maximum demand is the highest value of peak demand observed in the time period up to the year in question for each DNSP. It thus recognises capacity that has actually been used to satisfy demand and gives the DNSP credit for this capacity in subsequent years, even though annual peak demand may be lower in subsequent years;
- *Customer numbers*: the primary function of a distribution network is to provide its customers with access to electricity. Regardless of how much electricity a customer consumes, infrastructure is required to connect every customer to the network. The number of customers, therefore, reflects a significant driver of the services a DNSP provides. The number of customers is measured as the number of active connections on a network, represented by each energised national metering identifier;
- *Circuit length:* line length reflects the distances over which DNSPs deliver electricity to their customers. DNSPs must transport electricity from the transmission network to their customers' premises. Line length is measured in terms of the length of 'circuit' (the length of lines in service);
- *Reliability*: measured as the number of customer minutes off supply. It is a negative output because a decrease in supply interruptions is equivalent to an increase in output.[333]

Each of ratcheted maximum demand, customer numbers, circuit length and reliability have grown or improved more than energy delivered, which has remained flat over the period 2006–14.

For Energex, ratcheted maximum demand and reliability improved sharply over the period 2006 to 2009–10 (Figure 100). For the full period to 2014, average annual growth rates were 2.8 per cent per annum and 2.5 per cent per annum respectively.

[333] Economic Insights 2013; AER 2015a.

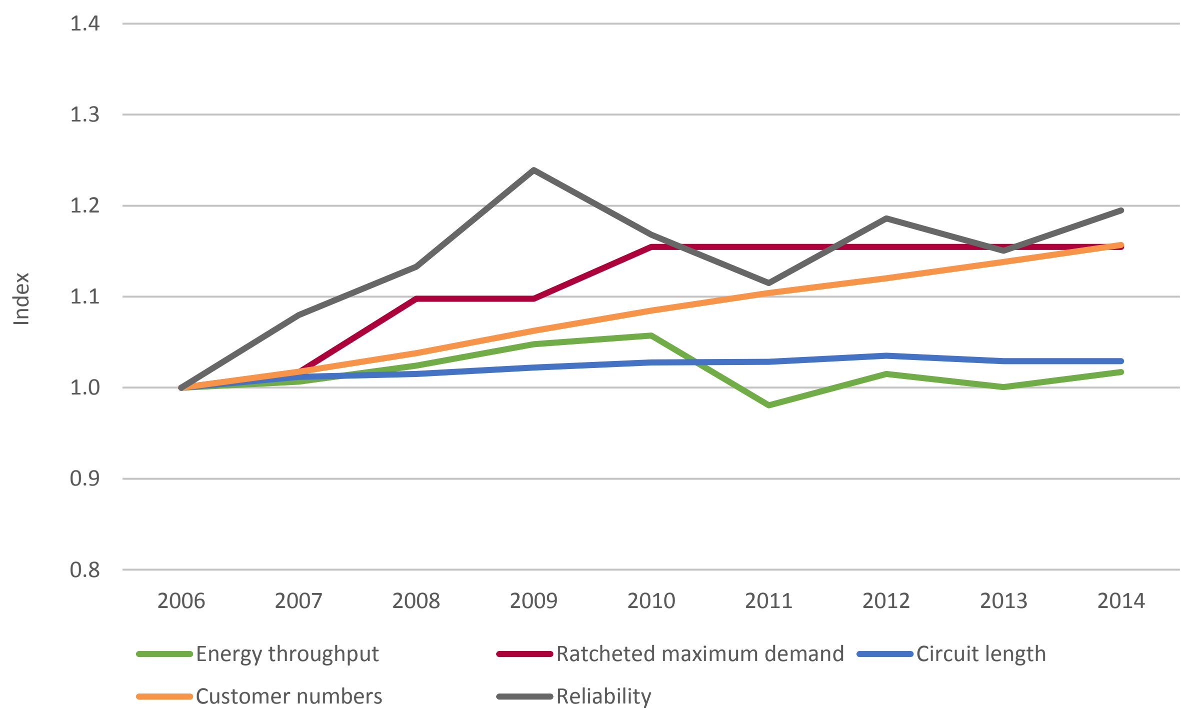
Figure 100: Growth in Energex outputs for 2006–14



Source: Energex 2015d; Economic Insights 2015a.

For Ergon Energy (Network), growth in ratcheted maximum demand and reliability was less at 1.8 per cent per annum and 2.2 per cent per annum (Figure 101). Customer numbers also grew reasonably strongly at 1.8 per cent per annum.

Figure 101: Growth in Ergon Energy outputs for 2006–14



Source: Ergon Energy Corporation 2015c; Economic Insights 2015a.

Inputs

Capital

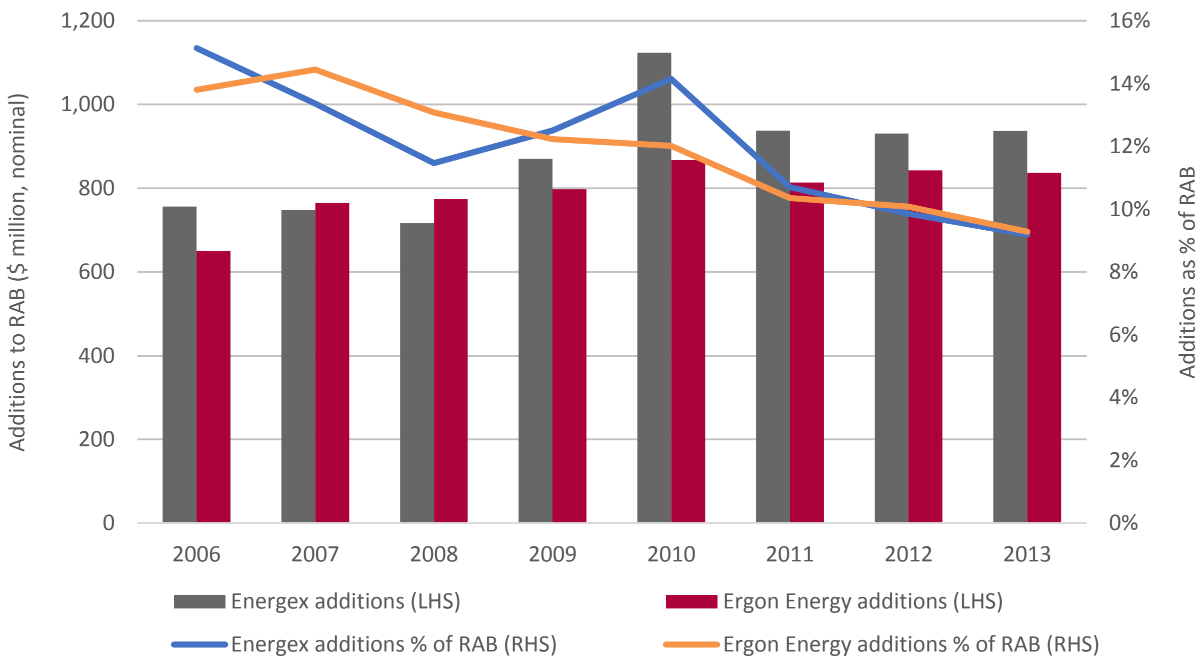
The specification of the AER's capital input index includes five physical measures of capital:

- the capacity of transformers;
- overhead lines above 33 kV;
- overhead lines below 33 kV;
- underground cables above 33 kV; and
- underground cables below 33 kV.

The AER considers that using physical values for inputs has the advantage of best reflecting the physical depreciation profile of DNSP assets. Asset values are not used in the measurement of capital inputs.

The regulatory asset base (RAB) used by the AER in revenue/price determinations has grown at a faster rate than the index of capital inputs used in productivity benchmarking. While growth in delivered energy has been suppressed for a sustained period, growth in the RAB of Energex and Ergon Energy (Network) has exceeded eight per cent of the closing value of their respective RABs each year from 2006 to 2013 (Figure 102). The average annual growth rate in the RAB for Energex and Ergon Energy (Network) was 10.2 and 9.3 per cent per annum, respectively. The RAB is calculated by regulators and forms the basis from which allowable revenues are calculated, affecting prices and a regulated entity's return 'of' investment (depreciation and return of capital) and return 'on' investment (profits).

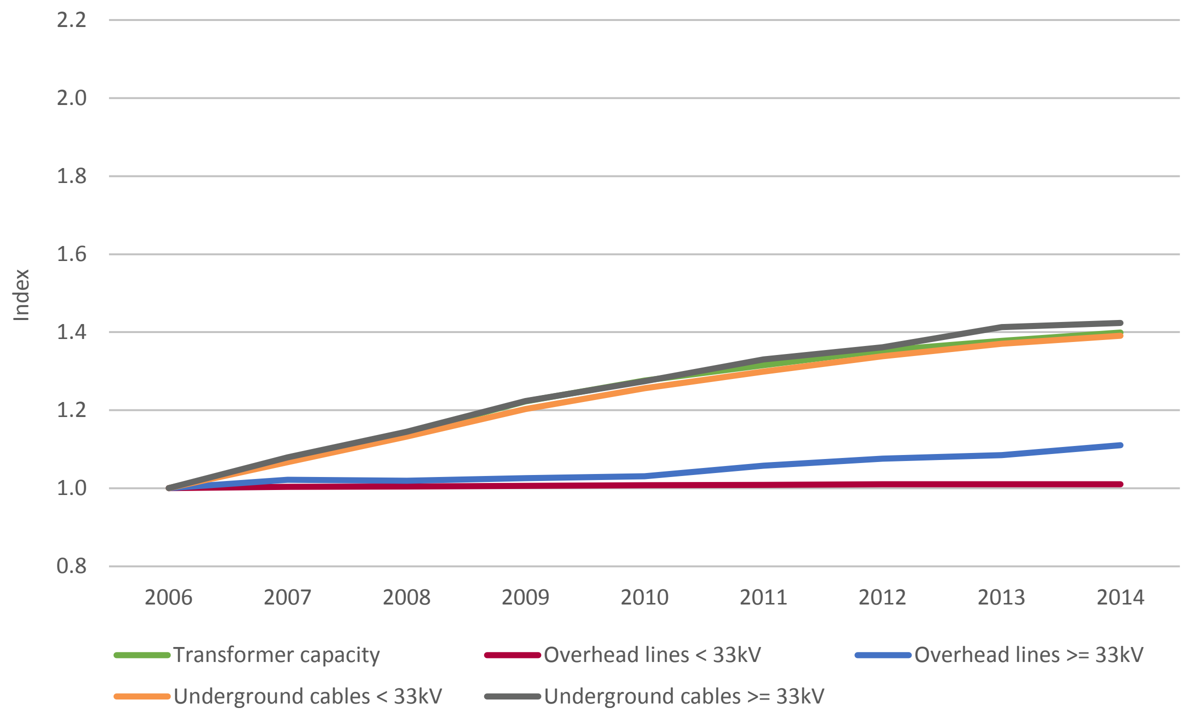
Figure 102: Additions to Energex's and Ergon Energy's standard control services RAB



Source: Ergon Energy Corporation 2015c; Energex 2015d.

For both Energex and Ergon Energy (Network), growth in the physical measures of capital inputs has been much more modest relative to growth in their respective RABs. For Energex, average annual growth has ranged from 0.1 per cent per annum for overhead lines less than 33 kV, to 4.4 per cent per annum for underground cables greater than or equal to 33 kV (Figure 103).

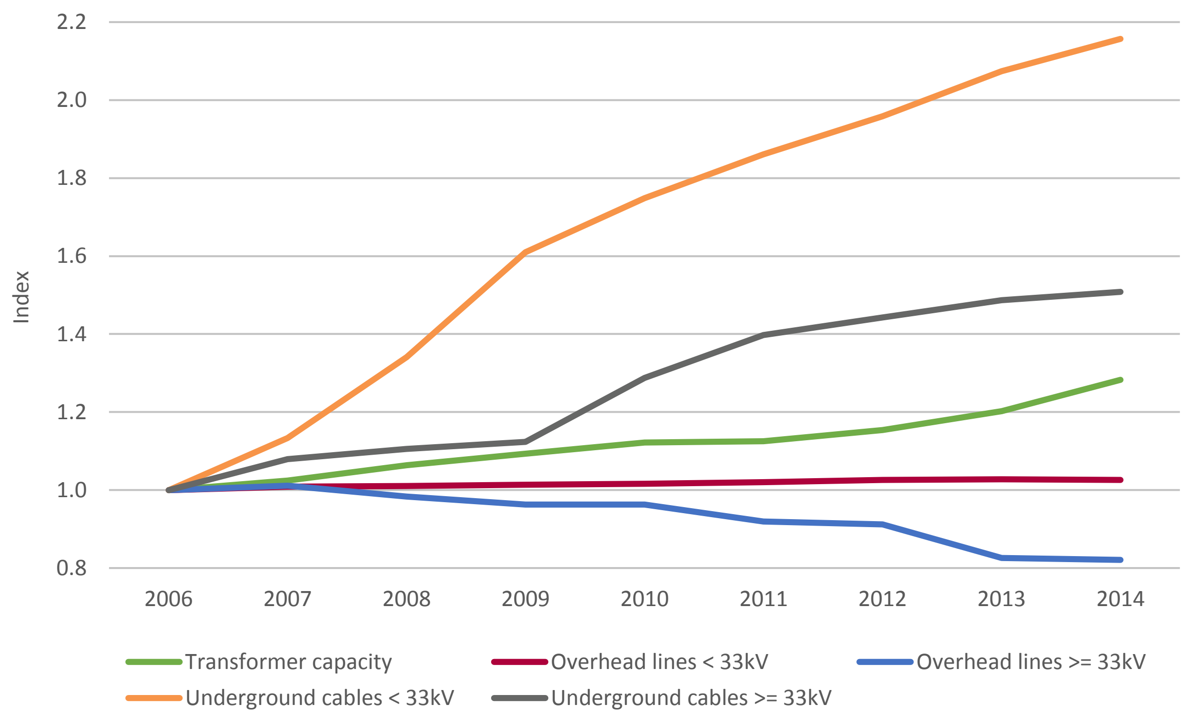
Figure 103: Growth in Energex capital inputs for 2006–14



Source: Energex 2015d; Economic Insights 2015a.

For Ergon Energy (Network), growth in capital inputs has been rapid for underground cabling with an average annual growth rate of 9.6 per cent per annum for cables below 33 kV and 5.1 per cent per annum for cables greater than or equal to 33 kV (Figure 104). Overhead lines greater than or equal to 33 kV posted a decline in average annual growth of 2.5 per cent per annum.

Figure 104: Growth in Ergon Energy capital inputs for 2006–14

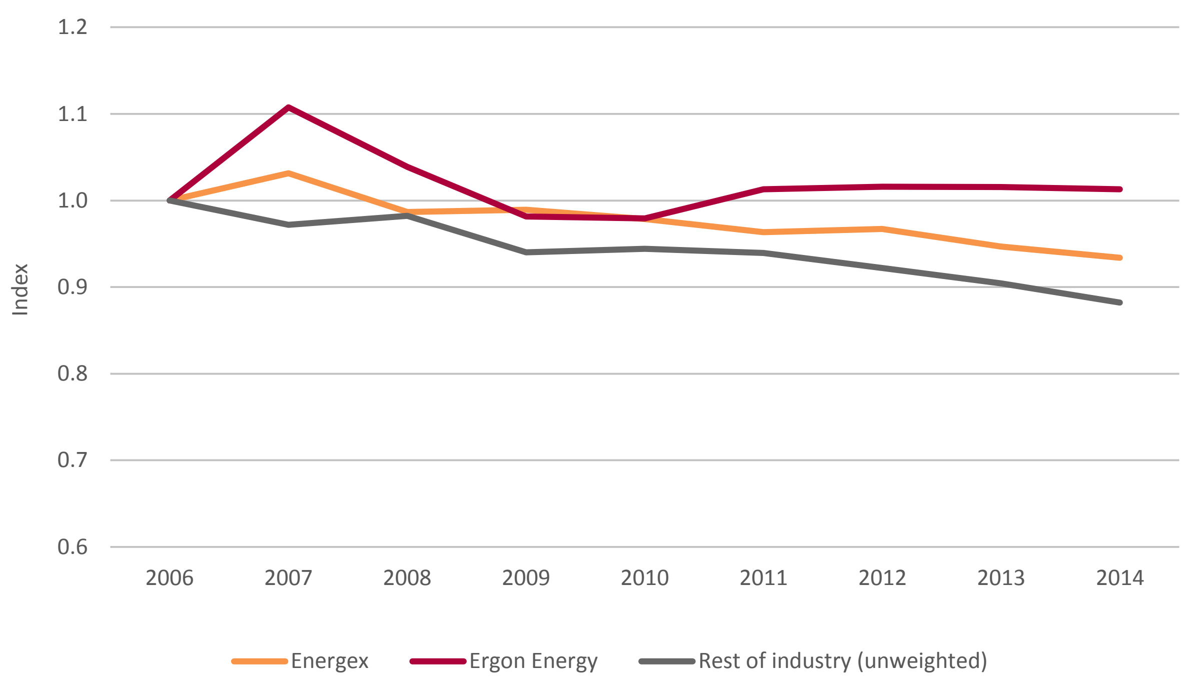


Source: Ergon Energy Corporation 2015c; Economic Insights 2015a.

For DNSPs in the NEM, sluggish output growth has combined with rising capital inputs to produce declining capital productivity from 2006 (Figure 105). Ergon Energy's capital productivity appears to have been fairly stable, while Energex's capital productivity declined at a slower rate than the average of DNSPs.

Capital productivity is a measure of the output achieved per unit of capital input, so it is affected by influences on outputs and capital inputs, including capacity utilisation rates.

Figure 105: Capital productivity for DNSPs for 2006–14



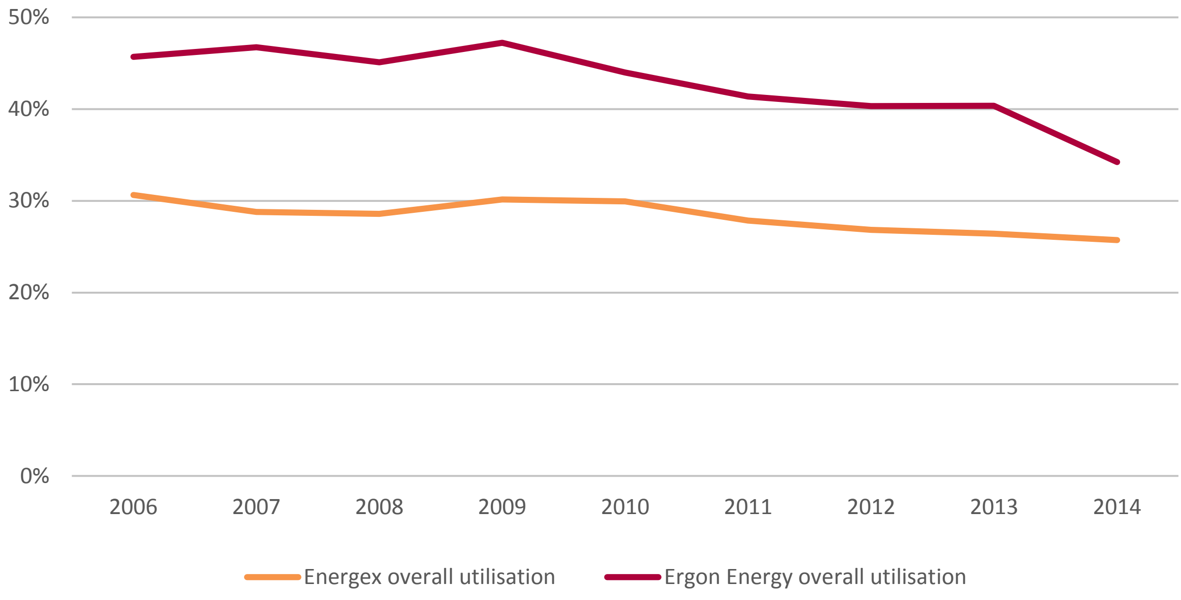
Note: 'Rest of Industry' is an unweighted index of each DNSP's capital productivity index.

Source: Economic Insights 2015a; QPC calculations.

While solar PV can provide investment delay benefits under certain conditions, it can also require capital expenditure (Appendix G). However, the level of solar PV related capital expenditure is not of a magnitude to have a material impact on the measured capital productivity indices.

Consistent with data on sluggish growth in energy throughput, network utilisation for Energex has declined from 30.6 per cent in 2006 to 25.7 per cent in 2014. For Ergon Energy (Network), utilisation has declined from 45.7 per cent in 2006 to 34.2 per cent in 2014 (Figure 106), consistent with flat output growth combined with rising capital inputs.

Figure 106: Network utilisation for 2006–14



Notes: Overall utilisation based on AER calculation.

Source: Economic Insights 2015a.

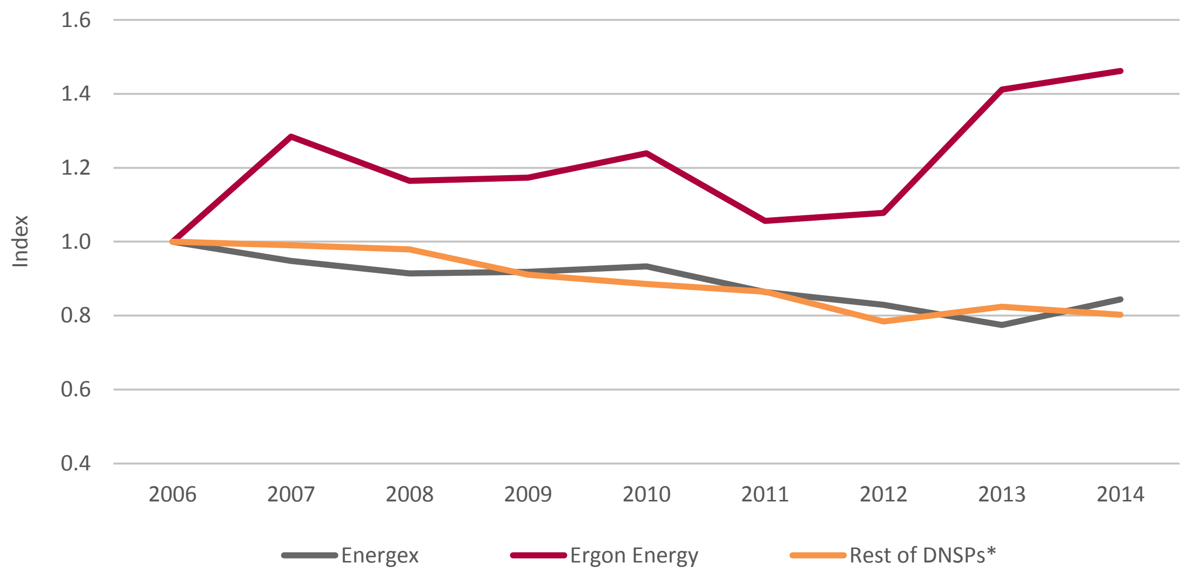
Operating expenditure

Similar to capital productivity, a partial productivity measure can be calculated for output as a ratio of operating expenditure. Operating expenditure includes operating, maintenance and other non-capital costs.

Operating expenditure productivity has declined since 2006 for most DNSPs, including Energex (Figure 107). The exception is Ergon Energy (Network) whose operating expenditure productivity has increased at 2.4 per cent per annum on average. Benchmarking has been adjusted to exclude the costs of the Solar Bonus Scheme.

A small but increasing proportion of operating expenditure is directed towards addressing solar PV–related network issues (Appendix G). Overall, the expenditure would not have a material impact on the operating expenditure productivity measure.

Figure 107: DNSP multilateral operating expenditure partial factor productivity indexes for 2006–14



*Notes: *Unweighted average of DNSPs excluding Energex and Ergon Energy.*

Source: Economic Insights 2015a; QPC calculations.

Solar impacts

Outputs

For solar to have unambiguously positive impacts on network efficiency, it needs to reduce maximum demand while not 'hollowing-out' average demand (as reflected in falling capacity utilisation factors). However, the substitution of electricity generated by solar PV panels for electricity provided from the grid is impacting almost entirely through reducing average demand. Ergon Energy (Network) has stated:

> *Ergon Energy designs and constructs our networks to meet the highest or critical peak, forecast demand in coming years. The highest forecast demand occurs on 70% of Ergon Energy's feeders in the evening. As PV systems are not generating at that time, they deliver no network benefit on those feeders. Rather, the PV generation delivers downsides such as higher network voltages and poorer asset utilisation.*[334]

The inclusion of outputs in addition to energy delivered in the output specification means that the lack of growth in energy delivered will have less of an influence on changes in the output index than otherwise, and therefore on measured growth. It also means that the output-suppressing effect of solar will have less impact on measured outputs and productivity under the AER's output specification. Not all solar generation reduces energy throughput, as a significant proportion of solar generated electricity is exported to the grid and delivered to customers.

For ratcheted maximum demand, at a whole-of-network level, solar has led to a small reduction in maximum demand and a much larger reduction in average demand (as noted above and discussed in Chapter 6).

For reliability, solar is having negative impacts on reliability on some feeders. Distributors expect this issue to become a more important driver of costs as penetration levels rise (discussed in Chapter 6 and Appendix G).

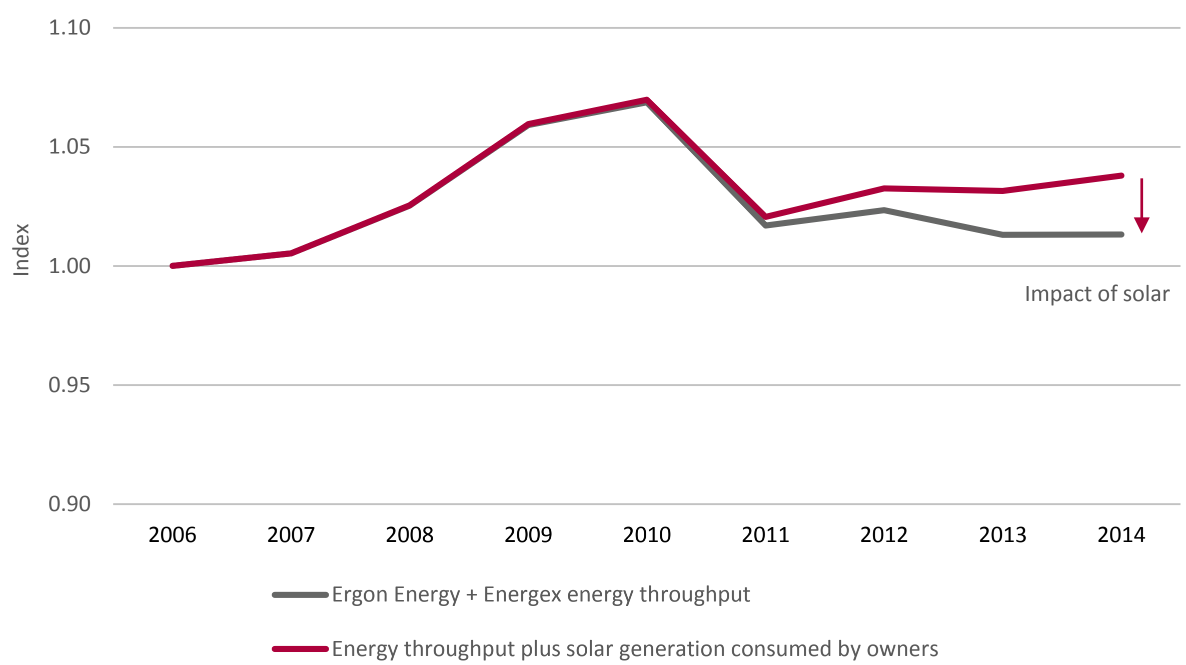
[334] Ergon Energy Corporation, sub. 34, p. 22.

Solar is unlikely to have had any significant impact on the other outputs measured by the AER in the short term:

- *Customer numbers*: as numbers of customers going 'off-grid' are very small to date, the rapid uptake of solar has not had a significant influence on customer numbers.
- *Circuit length*: solar investment has not affected total circuit lengths.

An output index based only on energy throughput shows the effect of solar PV in suppressing output growth since 2011 (Figure 108).

Figure 108: Queensland DNSP energy throughput with and without solar for 2006–14



Note: The solar adjustment excludes solar generated electricity that is exported to the grid and delivered to customers.

Source: Economic Insights 2015a; QPC calculations.

Inputs

Solar is unlikely to have had a significant effect on the following physical measures used in the capital index specification in the short term, and, thus, measured DNSP productivity:

- overhead lines above 33 kV;
- overhead lines below 33 kV;
- underground cables above 33 kV; and
- underground cables below 33 kV.

A larger proportion of a distributor's capital and operating expenditure is being consumed addressing solar impacts on network connection, management and reliability. Rising solar PV penetration levels are result in capital expenditures to address network problems caused by reverse power flows and feeder peaking reducing network reliability (Chapter 6).[335] In its 2015–20 revised regulatory proposal to the AER, Ergon Energy (Network) noted that:

[335] See the discussion in Ergon Energy Corporation, sub. 34, pp. 9–12.

The installation of solar PV had a twofold effect on the network:

- *It introduced an additional source of power for which, in the main, the networks were not designed for. This created immediate engineering, policy and regulatory issues.*
- *The pattern of solar generation is such that the peak demand has not significantly dropped, whereas overall consumption has. The net effect was that Ergon Energy was still investing in some parts of the network to cater for the peak, yet there was substantially less units of electricity being distributed.*[336]

Ergon Energy (Network) indicated that benefits from solar are more likely to arise on those feeders typically serving commercial and industrial businesses:

Around 30% of Ergon Energy's feeders have day-time peaks (that is, before 5pm) and PV generation can reduce those peaks, at times. Those feeders typically serve industrial estates, commercial centres and shopping centres. Roughly, 25% of those feeders experience their peak demand between 3 and 5pm, and 50% between 2 and 5pm, when PV generation is declining rapidly and the volume of exported electricity declines more rapidly. However, it is the very highest of those day-time peaks that determines the network capacity that must be ensured.[337]

Overall, a range of anecdotal information and partial indicators suggest that solar PV has had a net negative impact on network costs to date.

Multifactor productivity

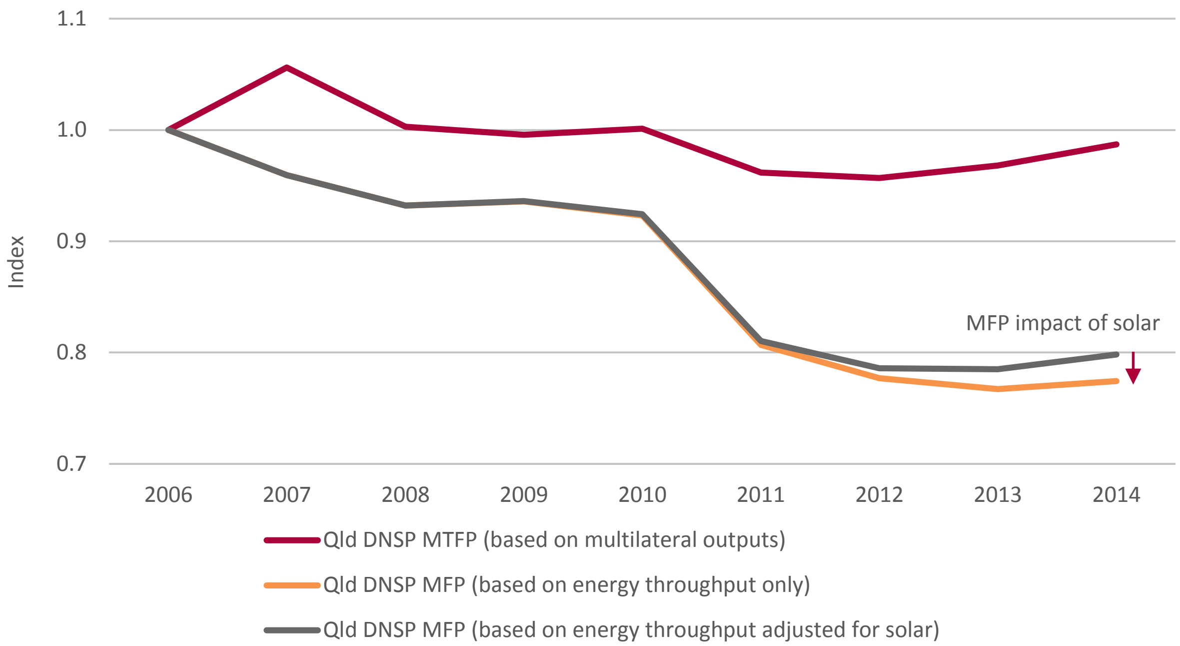
Systemwide information is not available on the magnitude of the cost impacts of solar PV on Queensland's DNSPs — either capital costs or operating expenditure. For the purpose of the MFP sensitivity tests below, it is assumed that the cost increases driven by solar on many feeders are offset by cost benefits on other feeders. Therefore, the change in MFP is driven solely by the output-suppression effect of solar PV on network energy throughput. With strong continued growth in solar PV investment under modelled base case assumptions, this effect will become much more significant over time.

MTFP for Queensland DNSPs has changed little from 2006. Using the same index, but with outputs based solely on energy throughput, results in the index declining to a value of below 0.8 by 2014. As discussed earlier, the 'other' outputs have remained stable or have grown, while energy throughput has declined.

If the reduction in energy demand from the grid that results from solar generation is added back to DNSP energy deliveries, then the resulting decline in productivity is less.

[336] Ergon Energy 2015d, p. 110.
[337] Ergon Energy Corporation, sub. 34, p. 22.

Figure 109: Queensland DNSP productivity with and without solar for 2006–14



Note: The solar adjustment excludes solar generated electricity that is exported to the grid and delivered to customers.

Source: Economic Insights 2015a; ACIL Allen Consulting 2015; QPC calculations.

APPENDIX I: MODELLING THE IMPACT OF WEALTH ON SOLAR INVESTMENT

Description of model/s and variables

To investigate the influence of income (wealth) on investment in solar PV, a range of econometric models were estimated on a single cross-section of Queensland regional areas (SA2s) data. The structure of the models was informed by:

- previous studies using aggregated postal area data, which found that a range of factors in addition to income and the expected financial return have influenced solar investment behaviour; and
- the temporal pattern of solar investment with earlier investments occurring under the SBS and later investments occurring under different feed-in tariff arrangements.

Each of five models estimate two equations, with the first equation having a dependent variable based on the number of SBS installations in a region, SBS installed capacity, or the region's penetration rate (the number of solar installations divided by total dwelling structures). The second equation is specified similarly, but models non-SBS solar installations, capacity or penetration.

As well as varying the dependent variable across models, a number of other features of the models differ, in particular:

- Model 1: This model explains regional differences in installed solar capacity. It is specified to include an indicator of average solar PV system sizes (kW), as capacity can be calculated as a function of installation numbers multiplied by average system size. The system sizes were calculated from Energex and Ergon Energy data. A range of factors thought to influence installation numbers is included in the equation in place of actual installation numbers, such as the percentage of dwelling structures that are rental properties.
- Model 2: This model also explains regional differences in solar capacity, but the initial set of variables prior to testing did not include average system sizes. Further, the equation for non-SBS capacity includes SBS capacity as an explanatory variable. As SBS investment preceded investment under existing feed-in tariff arrangements, regional differences in non-SBS capacity might partly be explained by prior regional differences in SBS capacity.
- Models 3 and 4: These models explain regional differences in solar penetration rates. In model 3, the equation explaining non-SBS penetration rates includes SBS penetration rates as an explanatory variable. Model 4 explains non-SBS penetration using the same set of dwelling structures variables as the SBS penetration equation.

The objective of different model specifications is not to identify a single preferred model, but to investigate whether the effects of the variables, particularly relative disadvantage and access to economic resources, are consistent across alternative models.

A description of all dependent and explanatory variables is provided in Table 55.

Table 55: Description of variables

Name	*Description*
sbsinstall	Number of solar installations with a SBS feed-in tariff
nsbsinstall	Number of solar installations with non-SBS feed-in tariffs
sbscapacity	Aggregate capacity of SBS systems based on inverter rating
nsbscapacity	Aggregate capacity of non-SBS systems based on inverter rating
sbspr	Number of SBS installations as a percentage of total dwellings structures
nsbspr	Number of non-SBS installations as a percentage of total dwellings structures
tdwstruc	Total dwelling structures in an SA2
ohousesemi (# or %)	Number or percentage of total dwelling structures that are owner occupied separate houses and semi-detached dwellings
rental (# or %)	Number or percentage of total dwelling structures that are rental properties
sbsavgsz and nsbsavgsz	Average system size (kW) based on inverter for SBS systems or non-SBS systems. Installed solar capacity is a function of the number of installations and average system size.
irsd3(%)	Percentage of population in bottom three deciles of the Index of Relative Socio-Economic Disadvantage. This index is a general socio-economic index that summarises a range of information about the economic and social resources of people and households within an area (e.g. low income, low education, high unemployment and unskilled occupations). As this index focuses on disadvantage, only measures of relative disadvantage are included. This means that a high score (or decile) reflects a relative lack of disadvantage rather than relative advantage.
ioecores	Index of Economic Resources score. This index reflects the economic resources of households within an area. Fifteen variables are included, such as: household income, housing expenditures (e.g. rent) and wealth (e.g. home ownership). A high score indicates relatively greater access to economic resources. For example, an area may have a high score if there are: many households with high income, or many owned homes; and few low income households, or few households paying low rent.

Notes: Solar data is sourced from Energex and Ergon Energy. Other regional indicators are based on the ABS 2011 Census of Population and Housing, with data accessed through the Queensland Regional Database of the Queensland Government Statistician's Office. Solar installations and capacity data is as at October 2015.

Modelling results

Factors that influence the expected financial returns to solar investment, such as changes in subsidy policies and trends in the price of solar PV panels, could be expected to explain changes in solar investment within a regional area over time. But, as these factors apply similarly across regional areas, they will not explain regional differences in solar investment.

The number of owner-occupied houses and semi-detached dwellings has a significant, positive influence on installed SBS capacity and penetration rates, while the number of rented dwellings has a significant and negative influence (Table 56).

For the SBS capacity equations, testing of various income or wealth measures generally did not provide strong evidence of a statistically significant effect. As the models are estimated on aggregated SA2 data and not on household data, this may be a reason why the effect of wealth, and the ability to borrow to fund capital purchases, is difficult to isolate. In addition, the owner-occupied dwellings indicator may also be picking up differences across regions in capacity to borrow, where borrowing to purchase solar PV is against equity in home loans (or the taking of new mortgages). With that qualification, model 2 does provide an acceptable model where advantages in access to economic resources is significant and positively associated with higher levels of investment in solar. The result is consistent with the penetration rate models.

Table 56: Solar investment, wealth and neighbourhood effects

	Model 1	*Model 2*	*Model 3*	*Model 4*
Dep. variable =	*sbscapacity*	*sbscapacity*	*sbspr*	*sbspr*
tdwstruc	1.071 *** (0.029)	1.001 *** (0.033)		0.078 * (0.041)
ohousesemi(%)	0.330 *** (0.036)	0.273 *** (0.037)	0.389 *** (0.042)	0.353 *** (0.045)
rental(%)	–0.380 *** (0.045)	–0.380 *** (0.048)	–0.302 *** (0.055)	–0.343 *** (0.059)
ioecores		0.081 * (0.043)	0.274 *** (0.044)	0.228 *** (0.052)
sbsavgsz	0.944 *** (0.099)			
Intercept	–2.298 *** (0.225)	–1.116 *** (0.187)	0.257 * (0.148)	0.269 * (0.148)
Dep. variable =	*nsbscapacity*	*nsbscapacity*	*nsbspr*	*nsbspr*
sbscapacity		1.029 *** (0.033)		
sbspr			0.875 *** (0.018)	
tdwstruc	1.040 *** (0.036)			0.056 (0.040)
ohousesemi(%)	0.351 *** (0.043)			0.359 *** (0.044)
rental(%)	–0.286 *** (0.054)			–0.262 *** (0.057)
ioecores	0.071 ** (0.029)	0.070 *** (0.024)	0.034 ** (0.013)	0.201 *** (0.051)
irsd3(%)	–0.215 *** (0.031)	–0.205 *** (0.029)	–0.219 *** (0.027)	–0.214 *** (0.028)
nsbsavgsz	0.283 ** (0.144)			
Intercept	–2.436 *** (0.285)	–0.835 *** (0.112)	–0.160 ** (0.070)	0.031 (0.142)
Statistics				
# observations	512	512	526	526
R^2 1st equation 2nd equation	0.848 0.839	0.860 0.949	0.454 0.858	0.457 0.441
B-P Test of independence^	0.823 (0.000)			0.866 (0.000)

*Notes: Standard errors in brackets. *** Denotes significance at 1 per cent confidence level. ** Denotes significance at 5 per cent. * Denotes significance at 10 per cent. ^ Breusch-Pagan test of statistical independence. Correlation between equation residuals presented with p-value in brackets. Null hypothesis is that residuals are independent. The null is rejected in each of the models (models 1 and 4) where the second equation does not include the dependent variable from the first equation.*

All equations estimated in natural logs. The models were estimated using Seemingly Unrelated Regression (SUR). SUR takes advantage of the correlation between the contemporaneous errors of the estimated equations to produce more efficient estimates. SUR with FGLS also allows for the joint testing of the significance of explanatory variables across equations. Where variables are included in both the first and second equations, a joint test rejected in each case the null of the coefficient on the variable being equal to zero.

Source: QPC modelling.

Since the closure of the SBS scheme, solar penetration rates have continued to rise under a less-generous subsidy regime. Regional variation in installed SBS capacity (model 2) and SBS penetration rate (model 3) is significant in explaining subsequent regional variation in non-SBS solar capacity and penetration. As SBS penetration rates are well below potential solar saturation levels, there is scope for investment to be relatively greater in regions that already have relatively high investment. A plausible explanation is the presence of neighbourhood or social network effects, such as: neighbours may raise awareness of the option of solar investment and reduce risks associated with large capital investments in new technology; localised scale effects where installers are able to achieve economies of scale by operating on nearby houses; and regional differences in the intensity of the marketing efforts of retailers and installers.

Access to economic resources is highly significant in explaining regional differences in non-SBS capacity and penetration rates (models 1–4). A higher index score on the ABS Index of Economic Resources is positively associated with higher levels of non-SBS solar capacity and penetration rates.

The proportion of a region’s households in the three lowest deciles of the ABS Index of Relative Socio-Economic Disadvantage is negatively associated with the level of non-SBS solar capacity and penetration rates (models 1–4). A higher proportion of the most relatively disadvantaged households is associated with lower solar investment. Inclusion of the bottom three deciles in the indicator focuses on regional differences in the proportion of the population that are most relatively disadvantaged (compared to, say, including the average index score in the models).

Model testing

To produce best linear unbiased estimates, Seemingly Unrelated Regression (SUR) has the same requirements as Ordinary Least Squares (OLS) estimation — in particular, that all explanatory variables are exogeneous. The inclusion of the contemporaneous value of a dependent variable from one equation into another equation as an explanatory variable would violate this assumption. However, lagged values of the dependent variable, in the case of data with a time dimension, can be included, as the system of equations is recursive rather than the contemporaneous values being simultaneously determined.

While the regional modelling in this appendix is based on cross-sectional data, the relationship hypothesised between SBS investment and subsequent non-SBS investment is recursive in the same way. Nonetheless, models 2 and 3 were also estimated using OLS with each equation estimated separately. The magnitudes of estimated coefficients changed little and the direction of effects was unchanged. The models were also estimated with three-stage least squares with little change in the results.

In model 1, OLS estimation does not alter the estimates for the main variables of interest, but it results in the average system size variable becoming statistically insignificant in the SBS capacity equation, and the owner-occupied house and semi-detached dwellings variable becoming insignificiant in the non-SBS capacity equation. As the errors of the equations are strongly correlated, SUR may provide more efficient estimates.

Model 1 is specified as capacity being a function of installation numbers and average system size, with installation numbers replaced with a range of variables thought to influence installation numbers. A simple estimation of solar capacity on installation numbers and average system size in natural logarithms produces coefficient estimates at or very close to 1.0 (as would be expected given how the capacity variable is constructed). Model 1 was re-estimated imposing the constraint that the coefficient estimates on the average system size variables are equal to 1.0. In the SBS capacity equation, there is almost no change to the magnitude of the estimated coefficients on the variables of interest (the coefficient in model 1 for the unconstrained regression was 0.944 in any case). In the non-SBS capacity equation, the coefficient on ioecores is reduced from +0.071 to +0.056, with the other coefficients of interest largely unchanged.

Overall, the presented model results and the testing of those results suggest that the effects on solar capacity and penetration rates of relative socio-economic disadvantage for the least well-off is negative, and access to economic resources is positive.

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