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Paul Simshauser | Tim Nelson | Joel Gilmore

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Cambridge Working Paper in Economics CWPE2305

Paul Simshauser♣♦[1] Tim Nelson♣ & Joel Gilmore♣

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1. Introduction

The rise of rooftop solar photovoltaic (PV) in Australia's *sunshine state*, Queensland, has been remarkable. As of late-2022, 43.3% of households had installed a rooftop solar system – the highest take-up rate in the world. This has had profound impacts on the power system – for utilities, participating households and non-participating households.

The purpose of this article is to examine the cause and effects of Queensland's rooftop solar PV fleet. The conditions which sparked the initial wave of installations comprised a combination of sharply rising household electricity tariffs, stalled household income growth, uncoordinated and overlapping policy subsidies by two levels of government (viz. a Commonwealth capital subsidy, and a State-level Premium Feed-in Tariff), rapidly falling technology costs and ultimately, a very competitive installer market.

The effects of rooftop solar PV are complex. At the whole-of-system level, the production contribution is significant. Queensland's fleet of rooftop PV systems produce ~9% of total demand, and during a critical event peak summer day can be expected to provide 15-20% of maximum demand. At a consumer level, participating households are unambiguously better off. But the regressive nature of the kilowatt hour (kWh) and volumetric electricity tariffs means non-participating households are exposed to hypothecated taxes associated with solar subsidies – and these funded a large component of early system installations. When policymakers become aware of such adverse effects, policy is *necessarily adjusted*. This occurred in Australia, albeit imperfectly.

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The case of Queensland is a fascinating case study in that once a majority of policy subsidies were removed, after a brief period of inactivity, solar PV take-up rates actually accelerated. Solar advocates had feared changes to 'premium' feed-in tariffs (P-FiT) would adversely impact rooftop solar PV market share. But the practical evidence from Queensland is the market was forced to become more efficient, from both a technology cost *and* installation cost perspective.

For utilities, the story is mixed. On balance, near-term impacts of solar PV have primarily been adverse.

- Generation investment opportunities have been curtailed as rooftop solar PV replaces utility plant market share. Although one could also argue, we believe, that generator investors have been spared the risk of stranded investments given the recent acceleration of 'net zero' climate policy in Australia.
- Network utilities now have a more complex set of dynamics to deal with including reverse flows and metering demand (none of which is costless). However, networks are revenue regulated and consequently have not suffered any direct financial impact per se.
- Retail supply businesses have lost material market share as consumers increasingly *'make their own'* electricity. Volumetric losses have been ~30% and in a static sense, retail supply customer asset values may be overly inflated during the privatisations since market start. But the outlook for such businesses may revert because, if there is a *'first law of decarbonisation'*, surely it is 'anything that can be electrified, will be'. So while grid-suppled household electricity demand has reduced, fuel switching is capable of reversing this trend.

We believe the challenge facing all utilities will be how to survive a *'droop period'* – that is, the period by which rooftop solar rises, but before fuel switching and household volume increases dominate.

This article is organized as follows. Section 2 provides a brief overview of industrial organization in Australia's electricity supply industry. Section 3 reviews relevant literature. Sections 4-6 explains the conditions which led to the rapid rise of rooftop solar PV, viz. sharply rising electricity tariffs, overlapping solar subsidies and falling technology costs; and Section 7 then analyses household take-up rates in Queensland from 2009-2022. Sections 8-11 analyse impacts on participating households, non-participating households and the power system, respectively, followed by conclusions.

2. Brief background to industrial organization in Australia's NEM

When the electricity supply industry was first formed in the 1890's, what we now refer to as the four primary industry segments, viz. generation, transmission, distribution and retailing, were constituted as vertically integrated monopolies for reasons of coordination and efficiency. Although one of the leading sectors of the economy from a productivity perspective throughout most of the 20th century (Joskow, 1987), by the 1980s sectoral performance across countries such as the US, Great Britain and Australia was marked by overcapacity and rising prices (Pierce, 1984; Hoecker, 1987; Joskow, 1987; Kellow, 1996; Newbery and Pollitt, 1997).

A global wave of microeconomic reform followed during the 1990s with the British reform being prominent. However, disaggregation of vertical monopoly electricity utilities and the introduction of competitive markets can actually be traced as far back as Weiss (1973) and the first documented reform occurred in Chile from 1978 (Pollitt, 2004). Limits to scale economies in power generation had been identified by Christensen and Greene (1976) and Huettner and Landon (1978). Indeed,

technology changes via the Combined Cycle Gas Turbine meant scale-efficient entry was contracting after more than 60 years of expansion (Joskow, 1987; Hunt and Shuttleworth, 1996; Meyer, 2012). With this backdrop, restructuring plans began to emerge in various jurisdictions. A wave of microeconomic reform swept through western economies during the 1990s, typically involving the vertical and horizontal restructuring of monopoly utilities and the creation of competitive wholesale power pools, often based on the British model (Newbery, 2005, 2006).

In the case of Australia, the pre-reform electricity supply industry structure was comprised of state-based vertically integrated monopoly utilities. During the 1990s, the four vertical monopoly utilities in Queensland, New South Wales, Victoria and South Australia were restructured into 16 portfolio generators, 5 transmission entities and 15 distribution/retail supply entities around state/NEM region boundaries.

In the post-reform era, a series of capital markets-driven mergers and acquisition (M&A) events occurred across horizontal lines (i.e. mergers of retailers to create 'scale') and across vertical lines (i.e. re-integration between retail and generation to create financial stability). Looking back, an *'electricity market arms race'* played-out over the period 1995-2015. The NEM's 'Big 3' retailers (or *gentailers* as they are referred to) emerged as winners from the string of horizontal, vertical and geographic privatisation and M&A events over this 20-year period. Vertical reintegration was the visible trend. Not only did the three incumbent retailers pursue vertical integration with merchant generation, but vertical integration also became the dominant strategy amongst incumbent merchant generators – many of which now have large retail businesses in their own right (albeit without an historically 'sticky' retail franchise customer base). A further 15-20 new entrant *pure-play* retailers form the competitive fringe.

M&A valuations were based on largely 'business-as-usual' metrics with a sticky mass-market customer typically valued at $1000-$1400 on acquisition, as Figure 18 subsequently reveals. Little did the utilities know that these customers, historically consuming ~7000 kWh per annum, were about to radically reduce their grid-supplied consumption levels *en masse*. Far from positive annual consumption growth of ~2-3% per annum, households reduced their grid-supplied consumption by ~30%.

3. Review of literature

Premium solar feed-in tariffs or P-FiT's have been used globally to incentivise residential solar PV, and in theory, rapidly decrease technology costs through economies of scale. At the end of the 2010s there were around 100 jurisdictions with active stimulus or FiT policies (REN21, 2019). Almost all policies were similar to Australian state-level schemes implemented from c.2010, viz. extremely generous FiTs. Critically, the cost of these schemes are usually recovered through levies or 'hypothecated taxes' on all electricity customer bills. In most countries and regions, take-up rates were much greater than expected leading to unexpectedly higher subsidy costs being levied on non-participating households. For low-income households, the financial detriment was predictable (Antonelli and Desideri, 2014; Simshauser, 2016; Winter and Schlesewsky, 2019).

Nelson et al (2011, 2012) observed that P-FiT policies are *regressively funded*. P-FiTs have the effect of gifting private benefits to homeowners through overly generous export rates, and, avoided network costs. Costs to non-participating electricity consumers are non-trivial and include recovery of P-FiT payments to solar households as well as reductions in capacity utilisation that drive higher network charges (viz. where volumetric pricing is used – as Section 8 subsequently reveals). The Australian policy literature focuses on equity impacts of P-FiT policies and tariff design by noting costs are disproportionately incurred by lower income non-solar households (see Nelson at al, 2011, 2012; Simshauser, 2016).

The literature into the motivations of participating rooftop PV households is both rich and geographically widespread. At a high level, research has found financial motivators are just one of many factors relevant for a household's decision to invest in solar PV.

3.1 The primary driver of early installations c.2010: subsidies

Using Australian data, Chapman et al., (2016) found state-funded east-coast P-FiT schemes were the primary drivers of early solar PV take-up rates. The size and number of installations *initially fell* after premium P-FiTs were abandoned (although as Fig.6 subsequently reveals, in Queensland this was only a transient stalling of solar PV take-up rates). Simpson and Clifton (2015) found an announcement about reducing the P-FiT in Western Australia created a surge in installations before it was actually reduced.

In addition to state-based P-FiTs, capital subsidies were also available and delivered through a Commonwealth Government policy, known as the Small-Scale Renewable Energy Scheme (SRES). This national-level policy provided fixed upfront subsidies that, upon initial design, was excessively generous (i.e. providing the equivalent of 75 years of export payments for a household's solar PV output at the time of installation). By considering geographic discontinuities across subsidy factors, Best et al., (2019) demonstrate higher upfront capital subsidies drove solar PV take-up rates across Australia. They found that higher subsidies were correlated with higher installations. Their study also demonstrated a link between installations and state-level P-FiT schemes.

Importantly, studies show that potential adopters of solar PV are driven not just by explicit profitability but by the *expected change* in profitability for installing a solar system. This is an important observation. As our subsequent analysis shows, it was not just the explicit P-FiTs but the relativity of solar PV household income vis-a-vis retail tariffs and network charges. Klein and Deissenroth (2017) found a statistically significant spike in solar PV adoption rates in Germany in the period between i). when a reduction in a paid solar tariff is announced, and ii). when the change comes into effect. This suggests that the reduction in income is perceived as a 'loss' by potential adopters, leading them to take-up the incentive before it ends. In the Australian context, expected higher retail tariffs would drive higher PV take-up rates, and this led to reduced power system capacity utilisation, further increasing retail tariffs in an ongoing cycle (a.k.a. 'the death spiral').

3.2 Secondary and continuing drivers for solar PV installations

The literature indicates financial drivers are the primary motivator for solar PV take-up rates. However, many adopters may not be acting as purely rational economic agents, instead relying on other motivators such as *relative* payback period (compared to other household improvements) and 'gut-feel' (Salm et al., 2016). Evidence also exists to suggest the timing of personal economic circumstances is a factor in a decision by a consumer to install solar PV. Significant events that often prompt homeowners to install solar include planned home renovations, the receipt of an inheritance, home refinancing and retirement (Schelly, 2014; Rode and Weber, 2016; Bondio et al., 2018).

Social context intersects with financial drivers in a number of complex ways. Community expectations and policy incentives can work together or against each other. As an example, P-FiTs in Germany initially drove limited solar PV take-up rates until public opinion reached a threshold. Italian solar PV take-up rates were also low initially, but then surged when awareness increased and community expectations were altered (Candas et al., 2019). This is again an important observation in the Australian context because of the 'wall of noise' around electricity

tariffs from 2010-2015 due to network price increases (see Section 4) and the 'climate change policy wars' that drove climate change policy discontinuity. Electricity had been a low-involvement product for decades but was suddenly on the front page of Australian newspapers for years due to these factors.

Common motivators from of solar PV participant and non-participant from research surveys includes protection from higher electricity prices (relevant in our subsequent analysis given the rapid run up in QLD electricity prices), the desire for energy independence (similarly relevant in our analysis given the rapid reduction in industry trust we identify in the Australian context), and environmental concern, although this is less relevant than the other two factors (Balcombe, Rigby and Azapagic, 2013, 2014; Karakaya, Hidalgo and Nuur, 2015; Korcaj, Hahnel and Spada, 2015; Bondio, Shahnazari and McHugh, 2018). Pro-environmental values drive *interest* in PV but are not the most important determinant of PV *take-up rates*.

The literature indicates household income is a key predictor of solar PV take-up rates (Kwan, 2012; Schelly, 2014; de Groote, Pepermans and Verboven, 2016; Briguglio and Formosa, 2017). In Queensland, there is a strong middle-income effect where middle-income households are the largest relative group of installers (Bondio et al., 2018; Best et al., 2019). For a summary of the research, see Dodd and Nelson (2022).

Another key aspect of the literature likely to be relevant to Australian and Queensland solar PV installation rates is *technology diffusion.* Bollinger and Gillingham (2012) were the first researchers to examine the role of technology diffusion in driving solar PV adoption in California. Solar PV take-up rates were higher in specific geographies (zip or postal codes) where rooftop PV had been previously installed. The diffusion effect was strongest at the local street level, suggesting a concentrated impact. Localised effects have been discovered in several geographies (see variously Graziano and Gillingham, 2015; Rode and Weber, 2016; Curtius et al., 2018; Parkins et al., 2018; Best, Burke and Nishitateno, 2019).

This diffusion process is again an important part of the solar PV story in Queensland and Australia. Solar PV deployment has not been evenly spread throughout Australian networks. Highly localised installation rates result in higher network costs per unit of energy deployed in those location. But these costs are spread across the entire non-solar group of customers.

Long-term relationships may also increase a sense of trust around the technology (Balcombe et al., 2014; Candas et al., 2019). Social dynamics are also likely to play a role in diffusion. Rode and Weber (2016) find a role for imitative behaviour in driving take-up rates amongst neighbours. In a survey of potential adopters in Switzerland, Curtius et al. (2018) find evidence of descriptive norms (what is considered to be typical or normal behaviour) and injunctive norms (what is socially expected) playing a role in the decision to invest in solar PV.

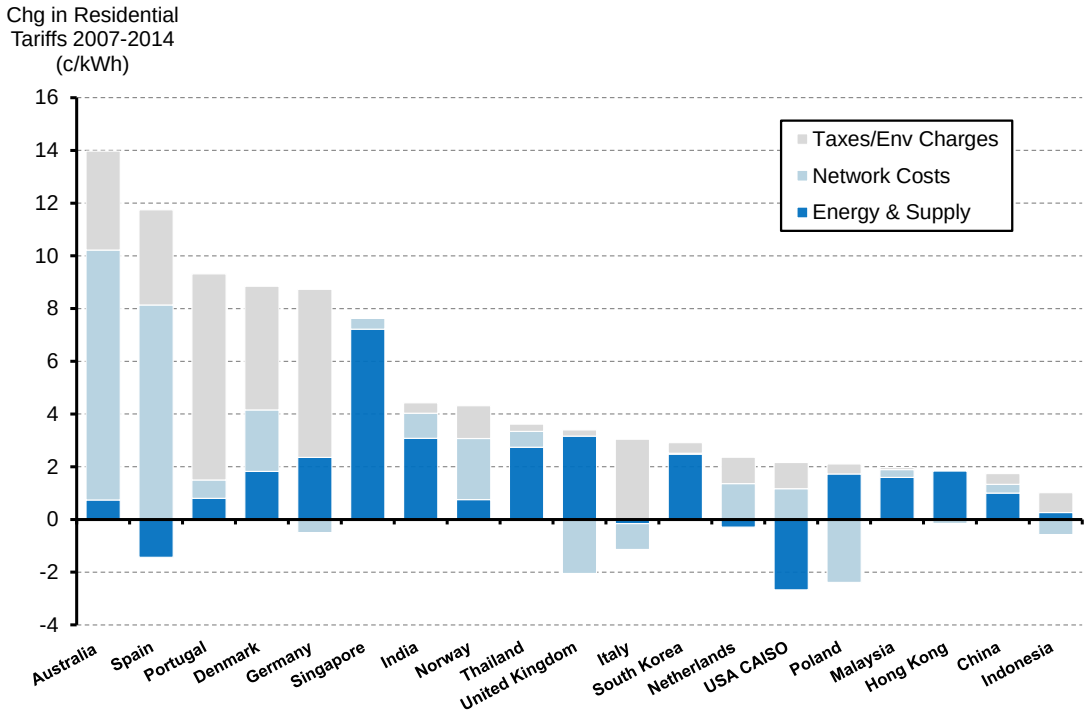
4. Queensland starting conditions: sharply rising retail tariffs

Why is it that Queensland has the highest rooftop solar PV take-up rate in the world? It was a combination of many factors commencing with sharply rising residential electricity tariffs and a commensurate rising level of 'distrust' of electricity utilities.

Queensland electricity consumers had historically enjoyed low electricity prices. Indeed, in 2007 Australia had the second lowest electricity prices in the world and Queensland was the second lowest cost region in Australia (Simshauser et al., 2011). Yet over the period 2007-2014, Australian electricity tariffs surged at the fastest rate in the world as Fig.1 illustrates. Fig.1 charts the change in household tariffs over the period 2007-2014 across various jurisdictions. Australian tariffs had

increased by ~US14c/kWh, and notice primarily by rising network costs and taxes / environmental charges. This would provide an important foundation for rooftop solar PV take-up rates.

Figure 1: Change in household electricity tariffs (2007-2014, USD)



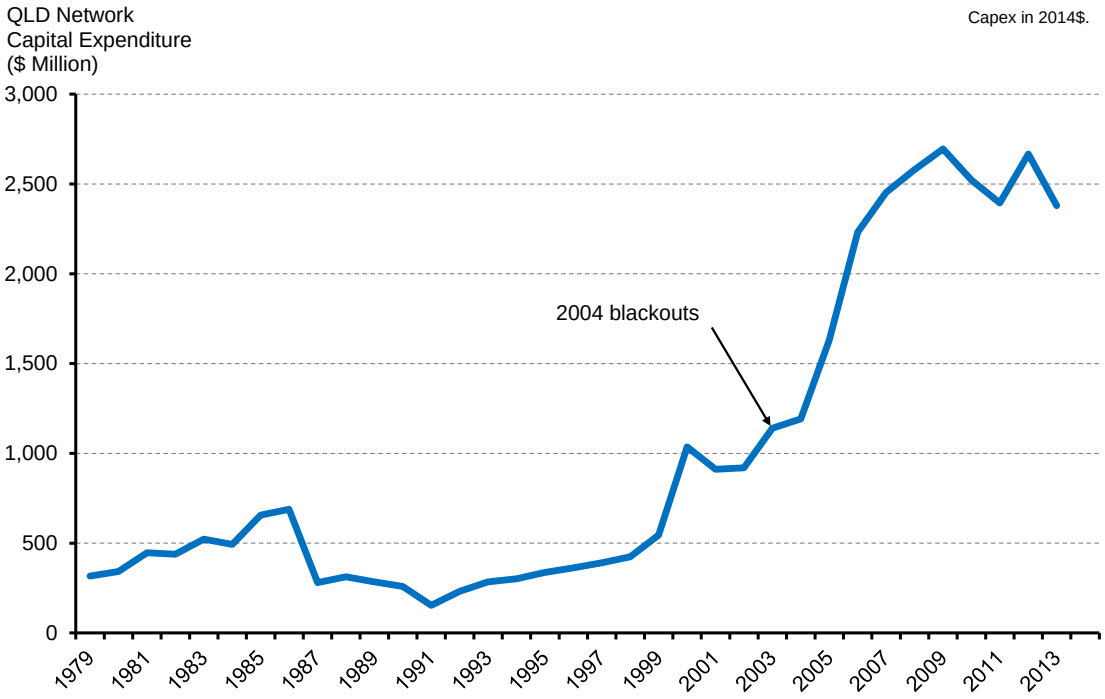
Source: Simshauser (2014).

The cause of these price rises started with a series of distribution network-related blackout events in the capital cities of Queensland and New South Wales (i.e. Brisbane and Sydney) in early-2004. In the case of Queensland, the local distribution network utility had been encouraged to lift profits and dividends to its government owners in prior periods. Capital and operating expenditures were reduced which included lowering vegetation removal expenditures and a thinning of line maintenance crews.

Weather conditions in early-2004 were severe. In late January, five storms hit southern Queensland over a 7-day window. The extent of vegetation damage to network lines was extensive – at one point 330,000 Brisbane households were without power. The cutbacks to line crews in prior periods meant restoration times were delayed. Just as the system was restored in February, the hottest weather in a decade prevailed and Queensland's first episode of 'latent peak demand' from residential air-conditioner installations was revealed.[2] Then in March, an east coast low weather pattern delivered three days of near-cyclonic winds and rain, thus repeating the events of January. Media coverage of blackouts was extensive and "an inquiry" was formed. Many sensible recommendations flowed from the inquiry but a recommendation to shift away from "probabilistic risk-based" network planning to a "deterministic N-1" approach was not one of them. It would result in a wave of capital spending (see Fig.2). This would fuel tariff increases.

[2] Household air-conditioner penetration rates had been rising sharply for years but the quantity of installations was unknown. Hot weather in February 2004 provided the practical evidence of installed units. We now know that in 2001 36.3% of SEQ homes had an air-conditioner and that by 2004 this had increased to 47% (*ca.*750,000 a/c units installed). By 2013, 74% of SEQ households had an air conditioner (*ca.*1.85 million a/c units installed). Almost a quarter of SEQ homes have 3 or more air conditioning units. Outside the Brisbane metro area but within SEQ, 76% of Gold Coast residents, 61% of Sunshine Coast residents, and 84% of Ipswich residents have an air-conditioner. The latest household survey indicates 79% of the population will have an air-conditioner by 2018.

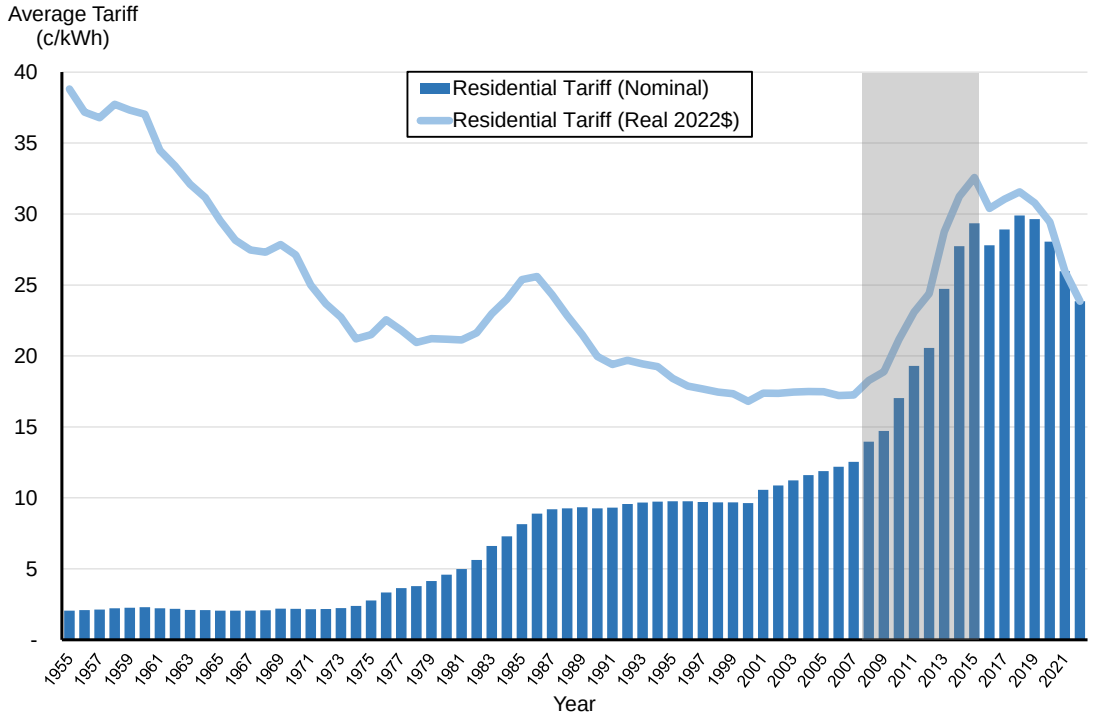
Figure 2: Queensland Network Capital Expenditure – 1979-2014



Source: Simshauser (2014).

The aftershock arising from this episode of capital expenditure is aptly captured in Fig.3, which illustrates Queensland's residential electricity tariff over the period 1955-2022 in real (line series) and nominal (bar series) terms. The grey-shaded area highlights the rapid run-up in prices following the capital expenditure surge outlined in Fig.2.

Figure 3: Queensland household electricity tariff (1955 – 2022)



What did this mean for the average Queensland consumer? Simply put, households that were spending $940 per annum for electricity supply in 2007 would be asked to pay $2,200 in 2015 – an increase of 134% in nominal terms while equivalised household incomes increased by just 22%. To put this into perspective, incomes

increased by (on average) 2.5% pa while electricity tariffs increased by 11.2% pa – and this pattern lasted for 8 consecutive years.

5. Overlapping rooftop solar PV subsidies

Policies to support rooftop solar PV can be traced as far back as 2000 with the Commonwealth Government's solar PV Rebate Program, which offered a $4,000 rebate for 1.5 kW systems. In 2007, this policy was renamed the Solar Homes and Communities Program with the rebate doubled to $8,000. Perhaps unsurprisingly, from this point the policy was constantly over-subscribed and amendments were made to include 'means testing' in order to limit the eligibility of households to those with a taxable income under $100,000. Applications increased tenfold during 2008 and 2009 due to the overlap with state P-FiT subsidies, which were introduced at that time.

As far back as 2007, individual Australian state governments began to develop policies to support the installation of rooftop solar PV even though the Commonwealth Government had an existing (and relatively generous) policy. South Australia introduced the first P-FiT in 2008 with a 54.0c/kWh net tariff (cf. retail tariff of ~20c/kWh and generation component ~7c/kWh). In practice, this 'net' FiT structure meant any solar PV export would be paid 54c/kWh while any self-consumed solar PV output avoided the prevailing 20c/kWh tariff. The only avoided cost was the 7c generation component. In contrast, the gross FiT structure which existed in New South Wales would pay the relevant rate to the entire PV unit output (i.e. both exported PV output, and self-consumed PV output). All east coast Australian jurisdictions introduced a P-FiT between 2008-2011. A brief description of the varying policies is provided in Tab.1.

Table 1: Feed-in Tariffs in Australia during 2008-2011

State	Max installation size	Rate c/kWh (gross or net payment)	Duration of PFiT	Comment
Vic	5kW	60c (net)	15 years	Commenced in 2009 – FiT credited on account or paid cash.
SA	30kW	54c (net)	20 years	The rate was capacity-determined with reduced rates for larger capacity increments.
NSW	10kW	60c (gross)	7 years	By far the most generous scheme announced, the scheme was very quickly reviewed, amended and then closed to new participants.
QLD	30kW	44c (net)	20 years	The rate was capacity-determined with reduced rates for larger capacity increments.
ACT	30kW	45c (gross)	20 years	The rate was reduced after a review by the independent regulator concluded a payback period of 7 years was acceptable

Source: Nelson et al, 2011.

The overlapping nature of these state policies with the Commonwealth $8,000 rebate resulted in an *explosion* of solar PV installations. This caused the Commonwealth Government to discontinue the rebate policy 'effective immediately' due to the significant strain on the Commonwealth's balance sheet from paying out rebates.

Because of the popularity of solar PV, the Commonwealth Government determined that a substitute policy was necessary. Amendments to the then 2% Renewable Energy Target (RET) were introduced that effectively transferred the very significant costs associated with supporting solar PV from the Commonwealth Government's balance sheet to electricity consumers (i.e. as a form of hypothecated tax on the electricity bill), with the resulting impact of driving electricity prices even higher.

Under the RET, Renewable Energy Certificates (REC) were issued to new renewable energy production, including small-scale solar PV. With the purpose of minimising transaction and administrative costs, RECs from rooftop solar PV were created 'upfront' through a deeming process. The deeming process effectively made an estimate of the first 10 years of electricity generation from each PV unit. The 'deeming' process had historically provided installers with $1,000 for a 1.5kW system.

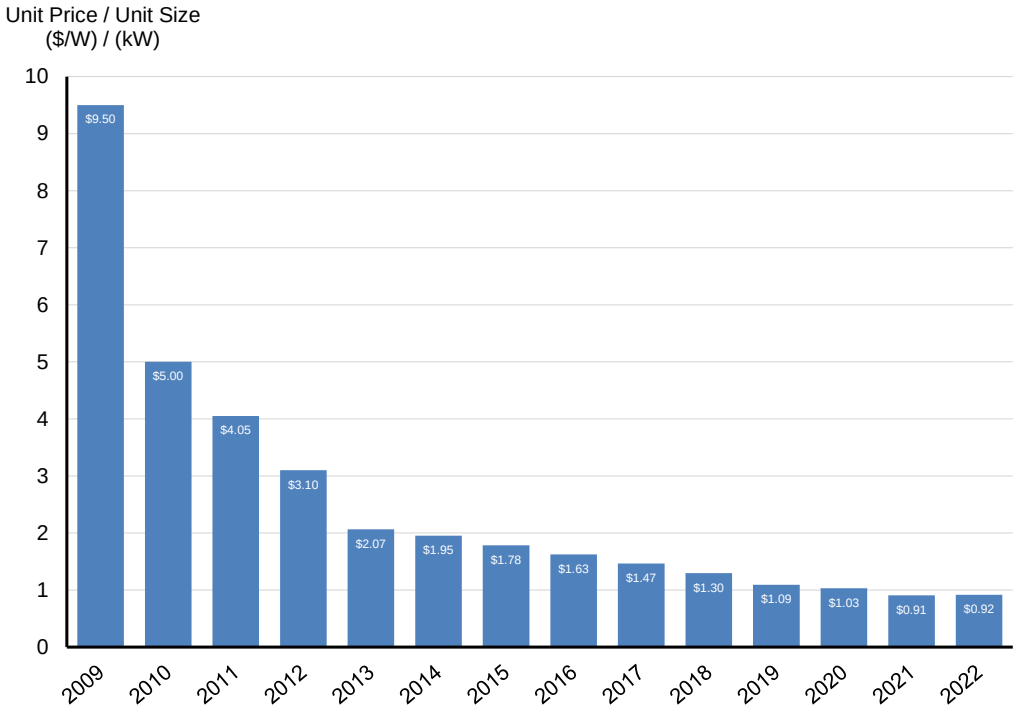
The RET was transformed into a 20% Renewable Energy Target (20RET) in 2009. The Government effectively transferred support for solar PV from the $8,000 taxation-system funded rebate to the 20RET through introduction of a 'Solar Credits Multiplier' within the new policy framework. The Solar Credits Multiplier (set to a *5-times* multiplier) increased the effective subsidy to rooftop solar PV from around $1,000, to ~$5,000 upfront for a 1.5kW system.

The continuation of overlapping Commonwealth and State Government subsidies for PV resulted in paybacks for solar PV being some of the most attractive of any investment option available to households across all asset classes. Nelson et al (2011) estimate that the payback in NSW was as low as 2.1 years and less than 10 years in Queensland. But crucially, all subsidies were now being recovered through higher network and retail charges for all customers, including non-participating households. This led to 'death spiral' conditions for utilities.

6. Falling costs of rooftop solar PV

Another important factor in Queensland's success vis-à-vis rooftop solar PV was the fall in technology costs and the competitiveness of the installer market. Fig.4 illustrates the fall in cost of installed rooftop solar PV ($/kW installed). Note in 2009 the observed market cost of rooftop solar PV was ~$9.50/kW but fell rapidly thereafter to current levels of ~$0.90–$1.00/kW.

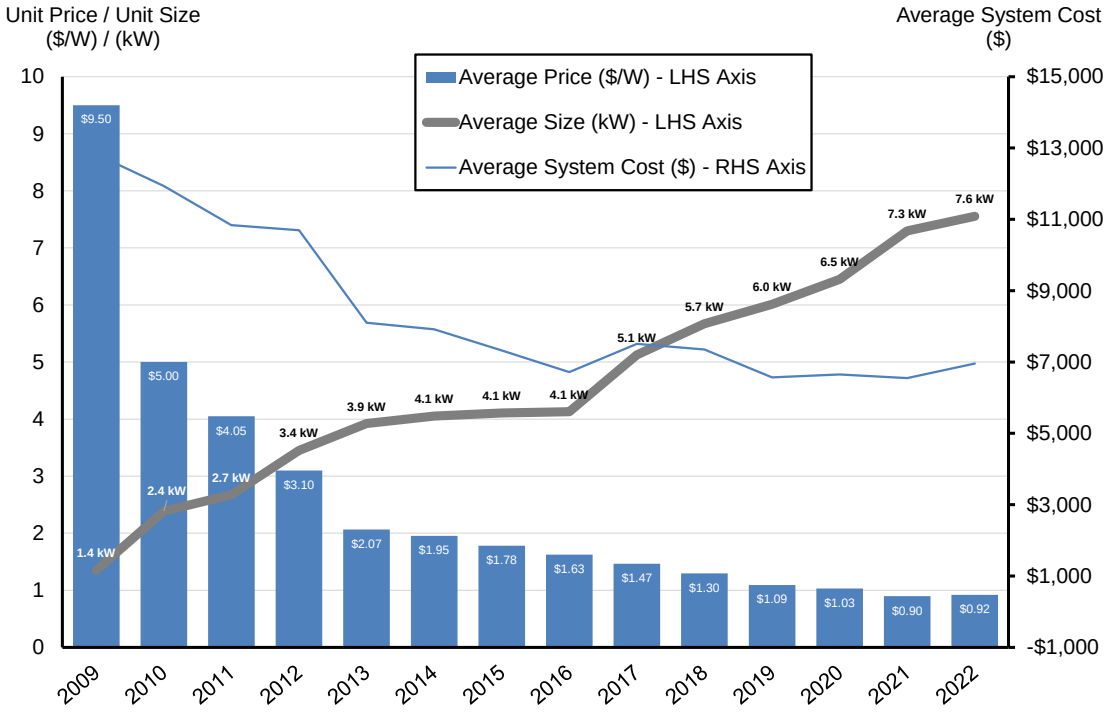
Figure 4: Queensland rooftop solar PV – installation cost/price per kW



Source: BNEF.

Most important was the step-reduction that occurred between 2012 and 2013, when installed costs fell to ~$2/kW. At this rate, and given the average (marginal) installation size at the time of 3.4kW, the installed cost had fallen to ~$7,000 gross or circa $5,500 (~USD$4,000) after the Commonwealth Government's upfront subsidy – low enough to fit on the family 'Visa Card'. Fig.5 shows marginal installation sizes (LHS axis) and the average system cost (RHS axis). Solar PV installations have become larger, and cheaper, over time with marginal installations currently averaging 7.6kW – facilitated by the size of Queensland's housing stock.

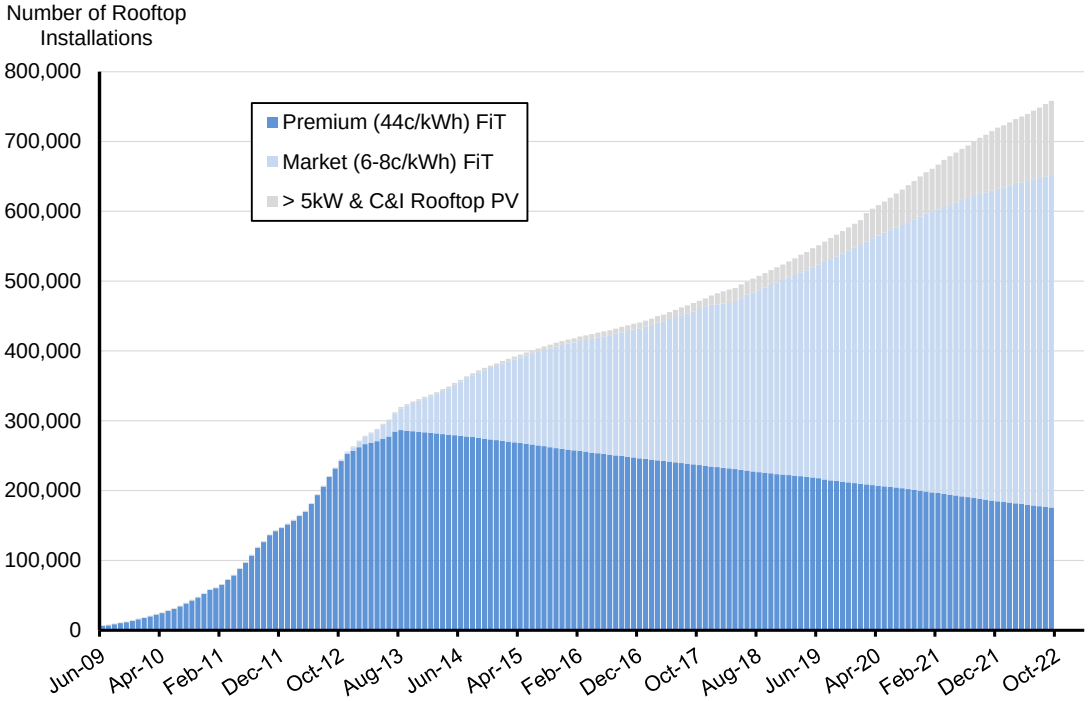
Figure 5: Queensland rooftop solar PV– installed size (kW) & cost ($) by year



7. Queensland household take-up rates

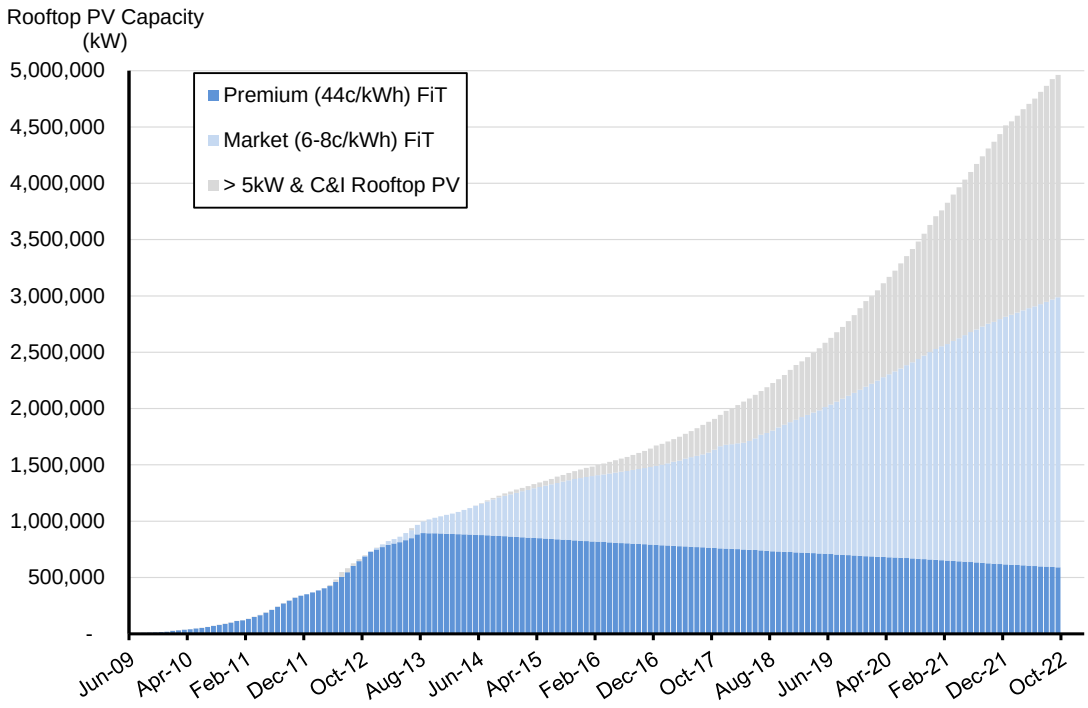
The combination of subsidies (Section 4), rising electricity prices (Section 5) and falling installation costs (Section 6) would produce a sharp runup in household take-up rates. Fig.6-7 present solar PV installations according to three distinct segments. The first segment represented by the dark blue bars are households who secured the Premium Feed-in Tariff of 44c/kWh. This segment declines over time in the event of a housing sale – the new owners are *not* entitled to remain on the premium FiT. The light blue bars represent households on a market-based FiT, which is currently ~6-8c/kWh (it is a competitive market). The grey bars represent commercial and industrial (C&I) customers who, axiomatically, install significantly larger systems.

Figure 6: Queensland rooftop solar PV – number of installations by segment



Source: Energy Queensland

Figure 7: Queensland rooftop solar PV – installed capacity by segment



Source: Energy Queensland, APVI.

How the household data in Fig.6-7 translates into take-up rates is illustrated in Tab.1 (along with data for all other Australian states). Queensland has the highest rooftop solar take-up rate at 43.3%. Installed capacity is 4,967MW and the output of these systems has a total energy market share of 9.0%. South Australia has the highest output market share of 17.0% (owing to its smaller industrial base and lower state-wide energy demand of 13,940GWh pa).

Table 2: Australian household Solar PV take-up rates (by State)

State	Population (millions)	Solar PV Takeup Rate	Energy Demand (Total - GWh)	Residential Dd (Grid - GWh)	Rooftop PV (MW)	Rooftop PV (GWh)	Rooftop PV Market Share
Queensland	5.2	43.3%	60,204	12,004	4,967	5,776	9.6%
South Australia	1.8	42.4%	13,940	3,767	1,987	2,365	17.0%
New South Wales	8.2	28.8%	72,348	20,972	4,807	5,353	7.4%
Victoria	6.7	24.1%	47,262	13,467	3,577	3,688	7.8%
Tasmania	0.5	18.3%	11,381	2,057	238	247	2.2%
NEM Total	22.3	31.6%	205,135	52,267	15,576	17,429	8.5%
Western Australia	2.7	37.5%	20,975	5,436	2,191	3,214	15.3%
Australia Total	25.0	32.2%	226,110	57,703	17,767	20,643	9.1%

Source: APVI, OpenNEM

8. Impacts on participating (solar) household

How rooftop solar PV impacts household energy demand is complex and depends on the location of the household, the size of the household, the appliance mix and the relative size of the rooftop solar PV system. Fig.8a-8b presents the typical Queensland household final demand during 'critical event' summer and winter days before the impact of a solar PV system installation. Consumption is measured at the customer circuit switchboard level (i.e. general power, air conditioning, electric hot water, lights and oven circuits). Total annual energy demand is ~7500kWh per annum and maximum demand is ~2.15kW. Note summer final demand (Fig.8a) is dominated by cooling loads, whereas winter (Fig.8b) is a combination of hot water and the air-con operating on reverse cycle.

Figure 8: QLD household demand (switchboard circuit level) pre Solar PV

Fig.8a – Critical Event Summer Days (average of 10 event days)

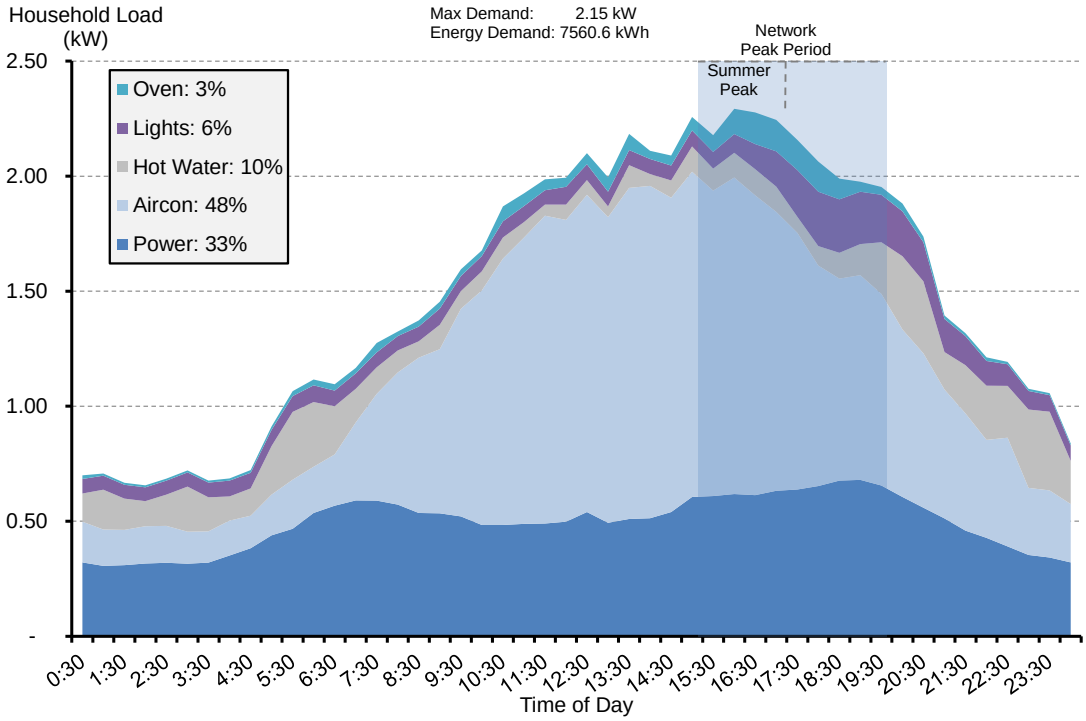
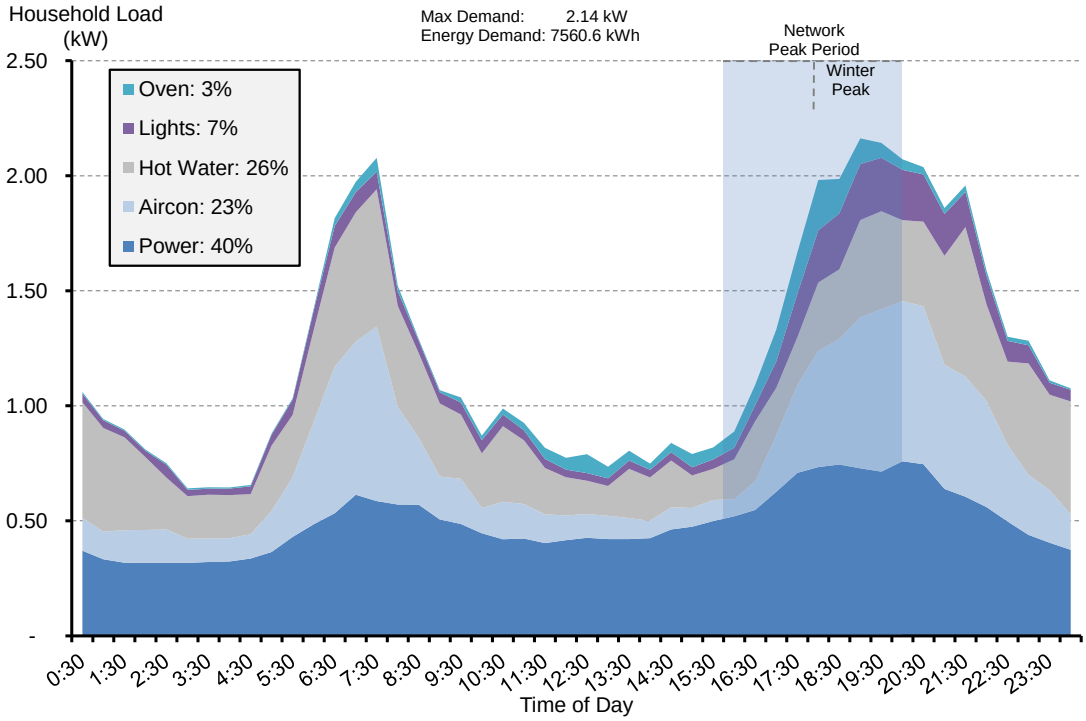


Fig.8b – Critical Event Winter Days (average of 10 event days)



The impact of rooftop solar PV of such households is illustrated in Fig.9a and 9b. The first point to note is that power flows reverse during the day (i.e. exports to the grid). Second, total household load is still 7500kWh per annum, but grid-supplied consumption reduces by 41% to 4480kWh per annum, and the solar unit exports 2750kWh pa back into the grid. The household therefore consumes 3080kWh of self-produced solar PV.

Figure 9: QLD household demand (switchboard circuit level) post-Solar PV

Fig.9a – Critical Event Summer Day (average of 10 event days)

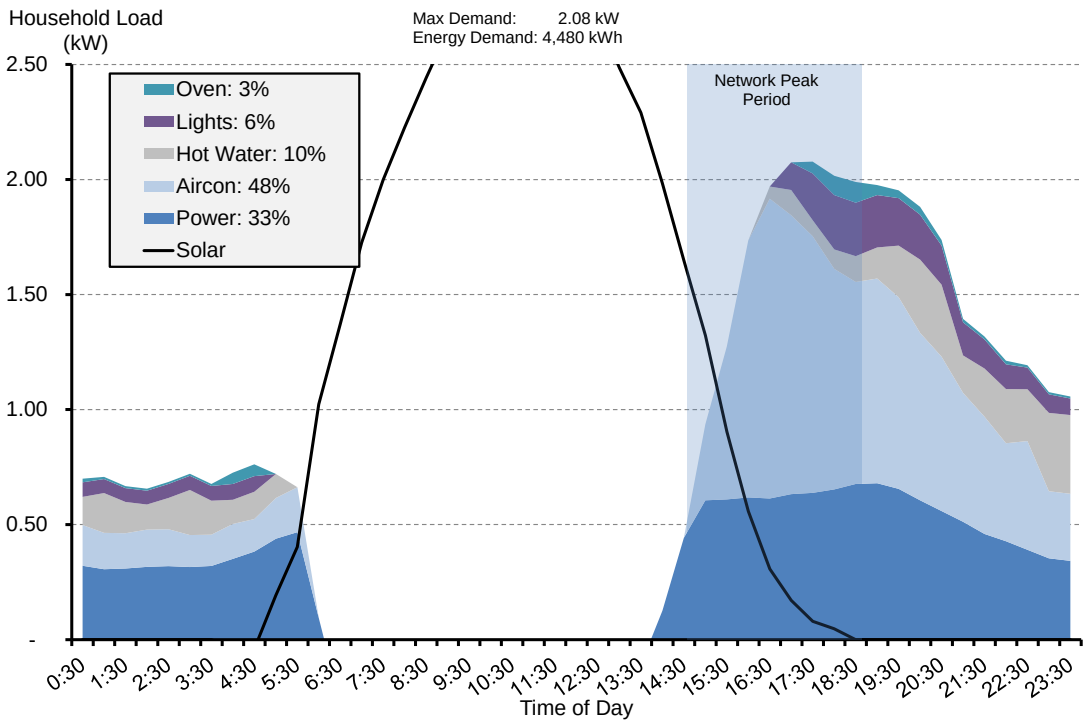


Fig.9b – Critical Event Winter Day (average of 10 event days)

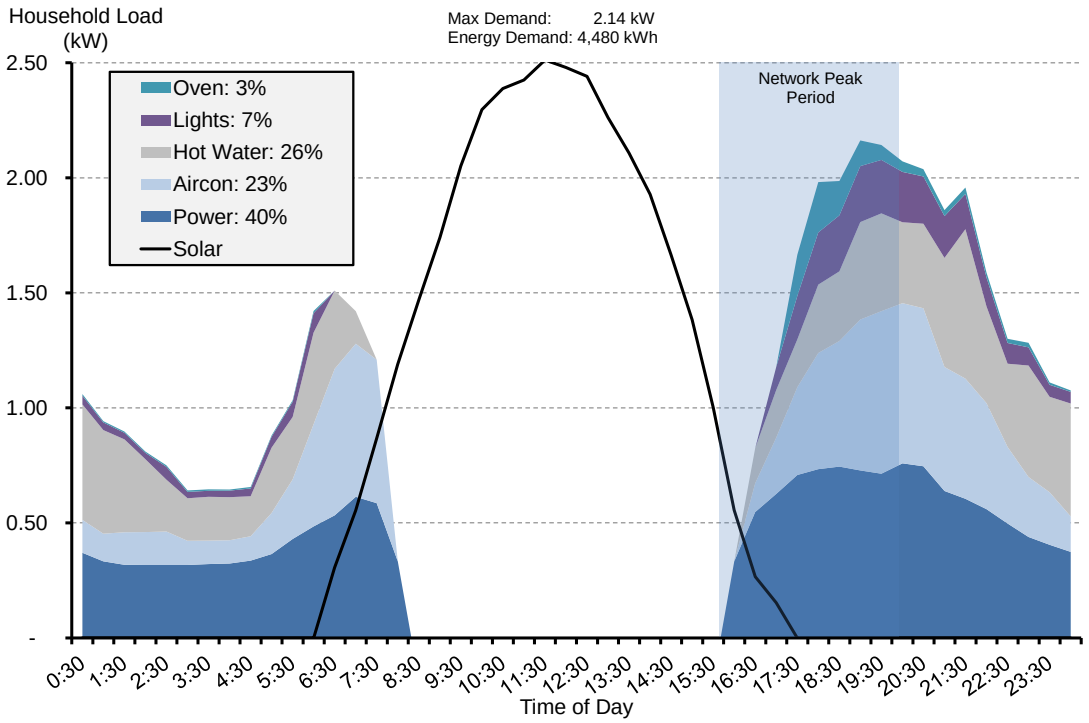


Fig.10 illustrate the impact of how solar PV size impacts on the 7500kWh household. Installing a 1.5kW system reduces grid consumption to 5570kWh pa (with virtually no exports to the grid. At the other extreme, a 6kW system reduces grid consumption to 4333kWh per annum, and solar PV exports back to the grid rise to 5500kWh pa.

Figure 10: Effect of solar PV on Queensland household grid consumption

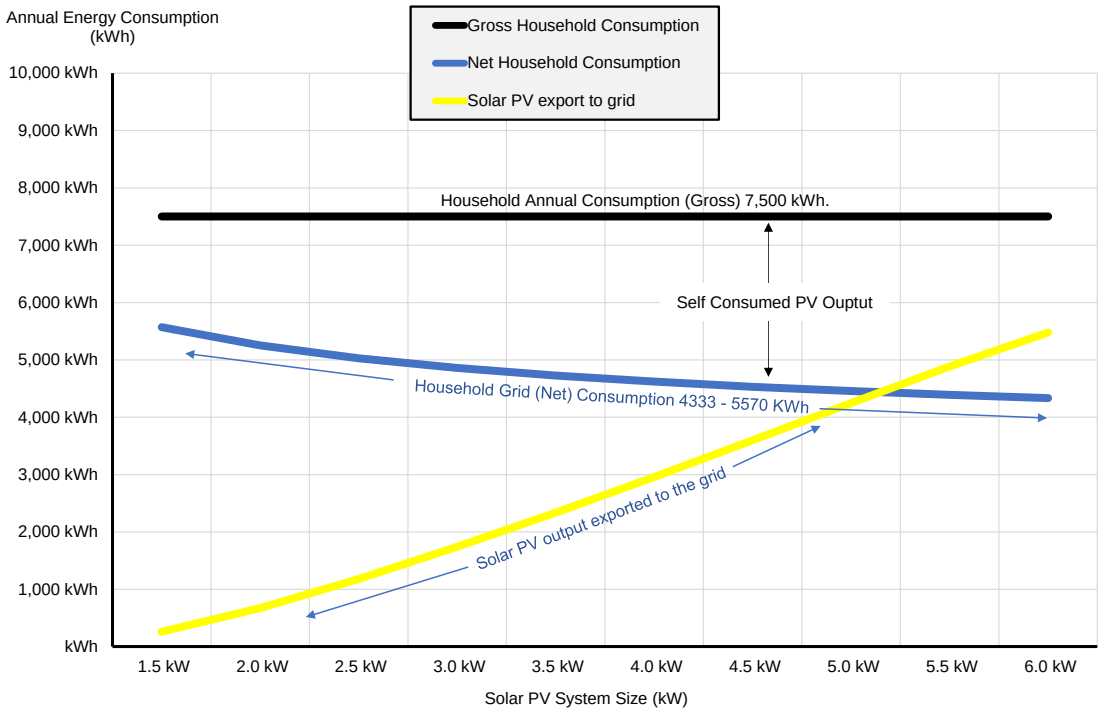
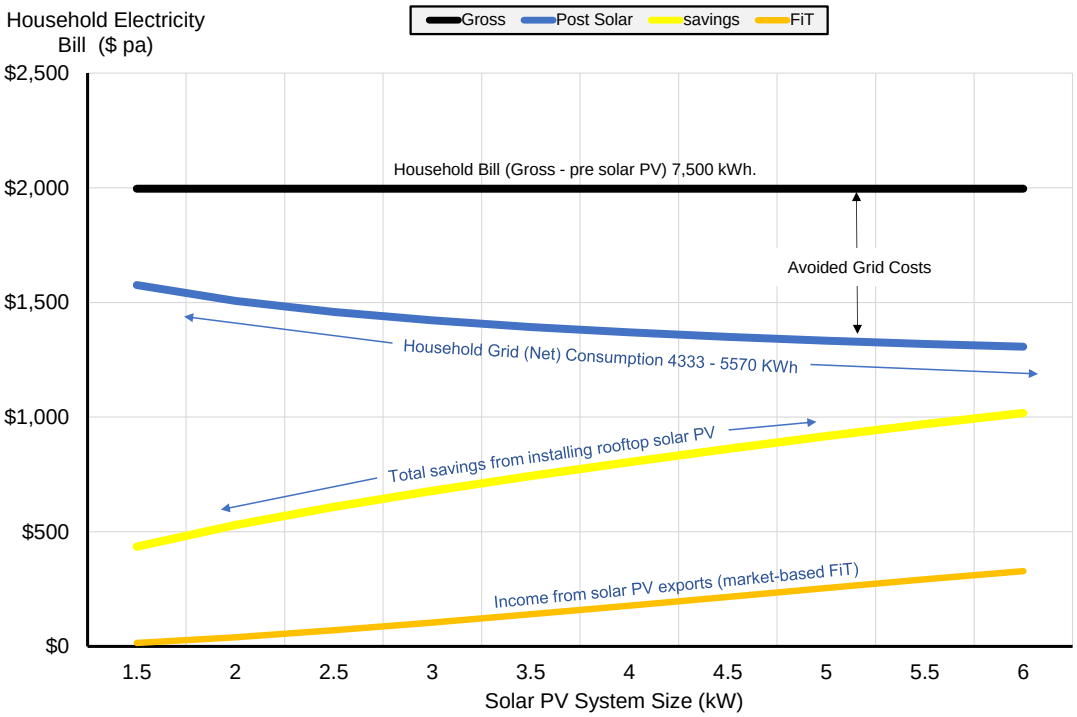


Fig.11 presents the same data translated to electricity costs and revenues, with exports assumed to be paid at 6c/kWh.

Figure 11: Household benefits arising from installing rooftop solar PV



To summarise the financial implications of our average Queensland household, at 7500kWh the annual electricity bill equates to $1976. Adding a 4kW solar PV system collapses the bill down to $1306 (down 34%). In addition, at 6c/kWh for solar PV exports, the unit generates ~$165 in rebates which is deducted from the bill (i.e. $1306 - $165 = $1141). In aggregate, the household avoids $835 per annum.

Participating solar PV households are unambiguously better off. Grid supplied electricity is reduced by 41% from 7500kWh to 4480kWh and solar exports of

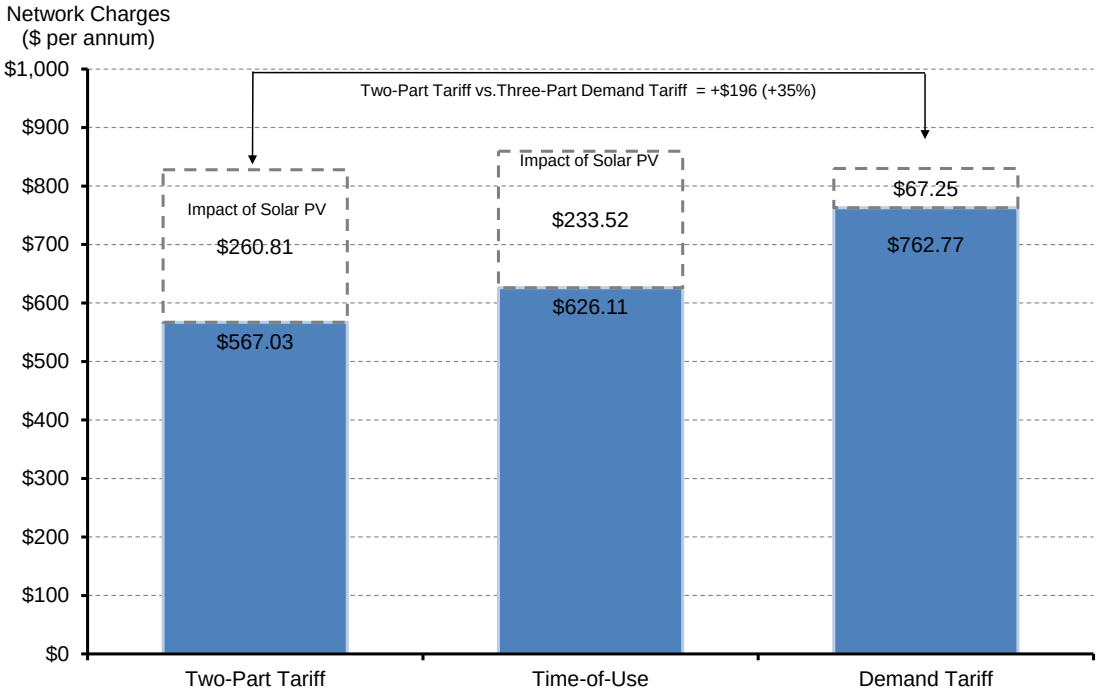
3080kWh generate additional rebates of $165. And the annual bill is reduced by 42%, from ~$1976 to $1441 (including the $165 rebate). What about non-participating households?

9. Impacts on non-participating (i.e. non-solar) households

The relationship between non-participating households and participating solar PV households is a complex one. For generation, initial studies suggested solar PV would produce merit order effects (McConnell *et al.*, 2013) but there is evidence that such effects are both complex and capable of reversing (Simshauser, 2020; Bushnell and Novan, 2021; Gonçalves and Menezes, 2022). In Queensland, the rooftop fleet has led to avoided generation plant of ~1500MW, and in this sense can be considered welfare enhancing (see Section 10 and Simshauser, 2022). For network charges, because the poles and wires businesses are 'revenue regulated', any avoided network charges by participating households will be disproportionately recycled to non-participating households. This can be estimated by benchmarking against a (*more cost reflective*) demand tariff (Simshauser, 2016). Consequently, whether sustained electricity supply-chain benefits exist to non-participating households remains an open question because the variables involved are dynamic and change over time.

For network charges, Fig.12 shows a comparison for the 7500kWh household examined in Section 8. Working from left to right, the first bar shows network charges after solar PV (~$567) and the avoided network charge (~$260) under prevailing two-part tariffs in Queensland. A time-of-use tariff is more cost reflective (second bar series) but the ideal charging structure is a demand tariff – and this shows that the avoided network charge should be ~$67 per annum, not ~$260 per annum. Consequently, non-participating households are essentially subsidising participating households by ~$193 per annum. For those requiring additional explanation vis-à-vis the intuition behind this result, and of detailed tariff design options, see Simshauser (2016).

Figure 12: Network tariff cross-subsidy

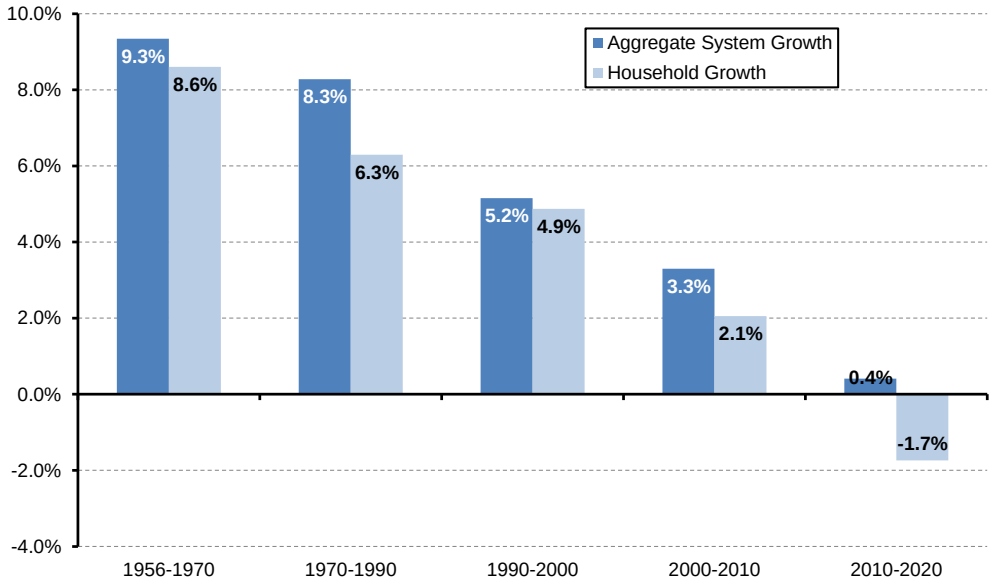


10. Impacts on the power system

With the ongoing take-up rates of solar PV, power system load growth has separated into two speeds, the residential segment in 'reverse gear', with commercial and industrials in 'low growth'. This is illustrated in Fig.13, which collates year-on-year load growth over the 65-year period 1955-2020.

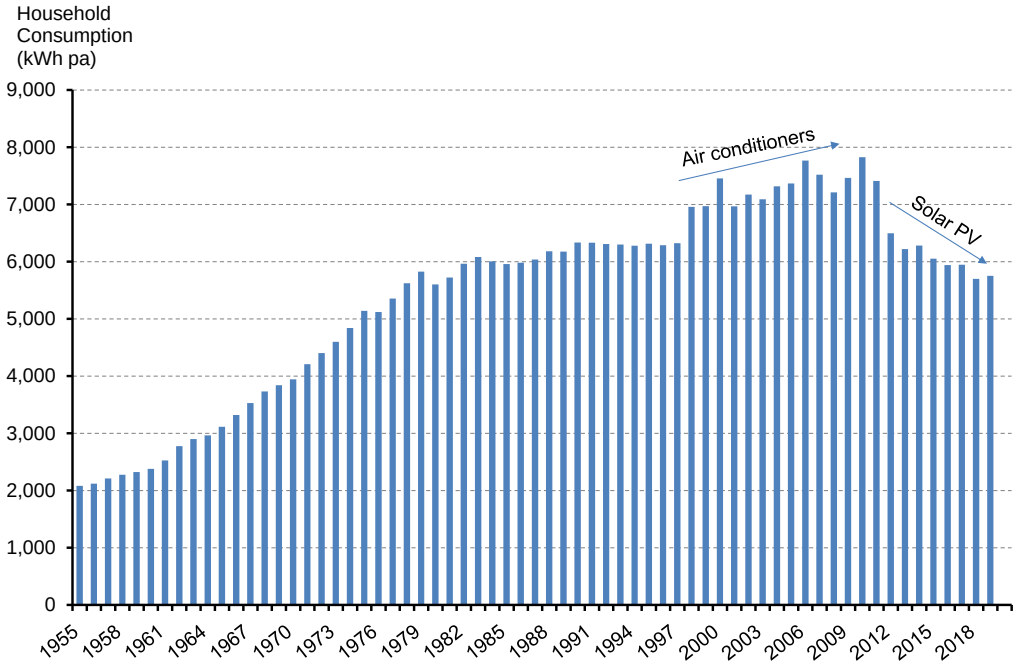
Notice that during the 1950s to 1970, load growth at the system level was 9.3% and the household segment was 8.6%. Over time, system and household load growth moderated – but of special importance to the present exercise is the data for 2010-2020. System growth has been +0.4% (i.e. the power system has experienced 'net growth') but the household segment has experienced compound annual declines in growth of -1.7% per annum, on average.

Figure 13: Trend growth in Queensland (grid) consumption 1955-2020



The trend in Queensland household (grid-supplied) electricity demand is illustrated in Fig.14 and highlights the run-up in air-conditioning loads, and the decline from solar PV.

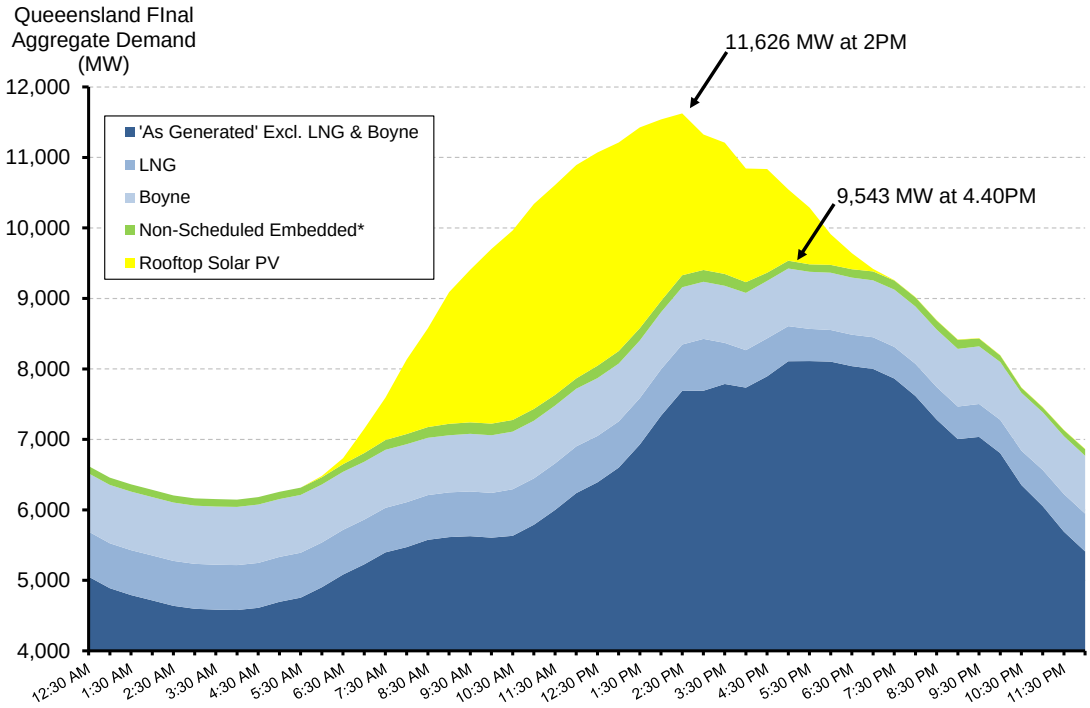
Figure 14: Queensland average annual household consumption



Source: AEC.

Rooftop solar PV impacts on the plant stock have been, perhaps unsurprisingly, material with approximately 1000-1500MW of utility-scale plant avoided. The reason for this is best illustrated through an analysis of total electricity consumption vs. grid-supplied consumption during a critical event summer day. This is illustrated in Fig.15.

Figure 15: Impact of rooftop solar PV on maximum demand (1-Feb-2022)



Note in Fig.15 that maximum final demand occurs at 2pm, at which point volumes consumed register 11,626MW. However, the grid-supplied peak demand of 9,543MW occurs much later, at 4.40pm. The difference between these two points is embedded generation (i.e. distributed renewable resources) but most prominently, behind-the-meter rooftop solar PV. As an aside, maximum grid demand occurred a month later at 10,180MW. Nonetheless, there is approximately 1500MW of avoided

generation comprising approximately 750MW of avoided base plant and 750MW of avoided peak plant (see Simshauser, 2022).

At a broader system level, resulting reductions in system capacity utilisation have been nowhere near as pronounced in Queensland as in other parts of Australia. This is shown in Figure 16.

Figure 16: Capacity utilisation across east-coast Australian markets

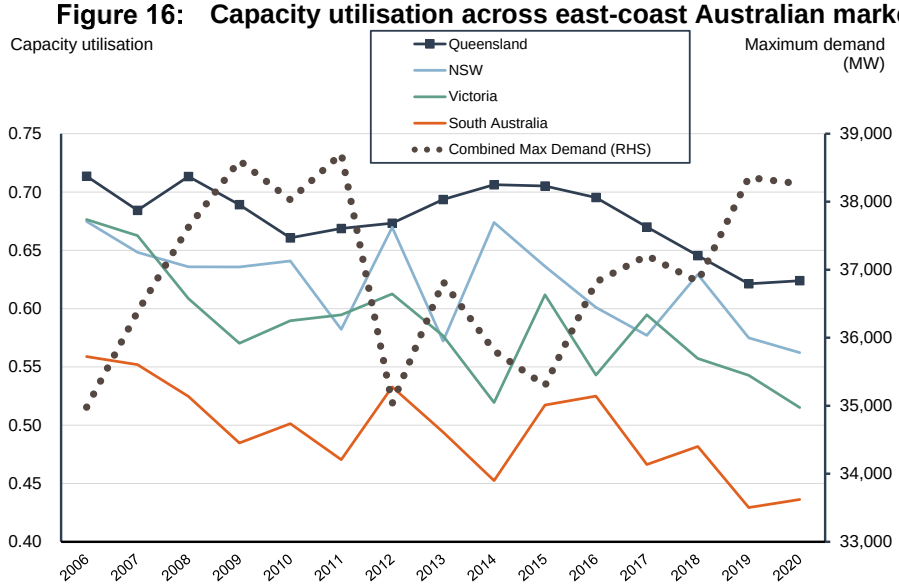
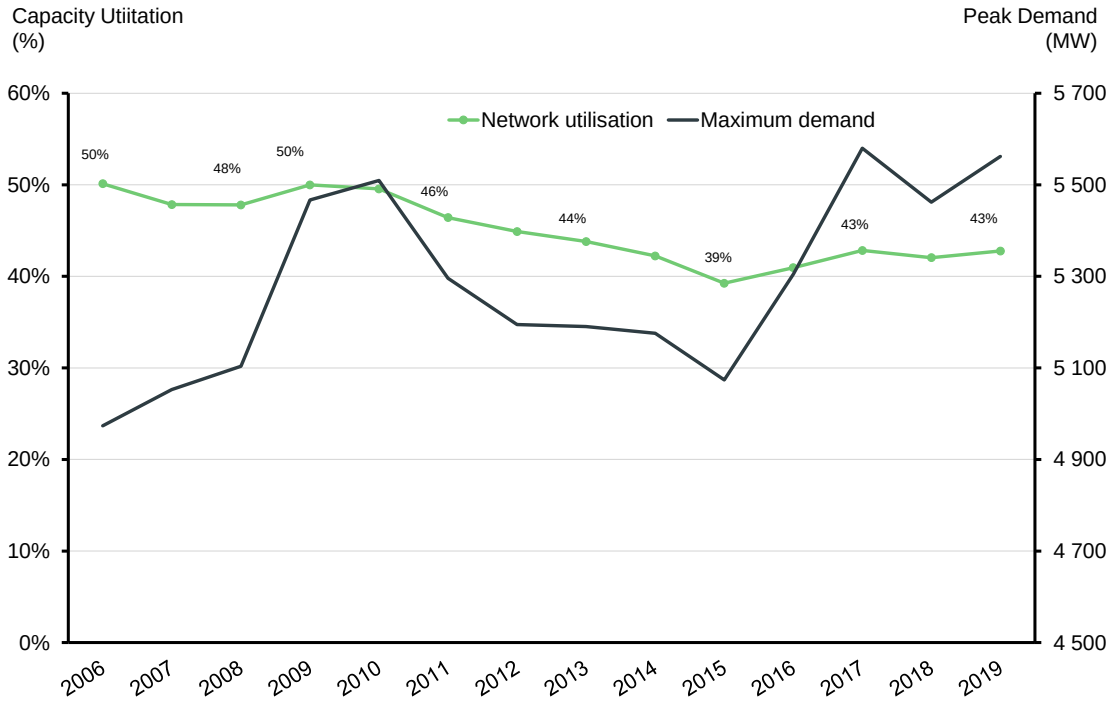


Figure 16 shows that capacity utilisation in Queensland has fallen from 70% to 63% since 2015. The relatively high-capacity utilisation in Queensland compared to other states is due to the emergence of new industrial electricity loads coming online over the past decade (i.e. coal seam gas and associated compression loads for LNG exports). When considered at a more granular (i.e. geographical) level, reductions in utilisation have been far more pronounced as shown in Figure 17.

Figure 17: Maximum demand & network utilisation in Southeast Queensland



Driven by population growth and air-conditioning installations, peak electricity demand in south-east Queensland distribution networks had increased markedly while utilisation of the network slowed through to 2015 (see Fig.17). Peak demand increased by ~12% while overarching utilisation fell from 50% in 2005 to 43% by the end of the decade.

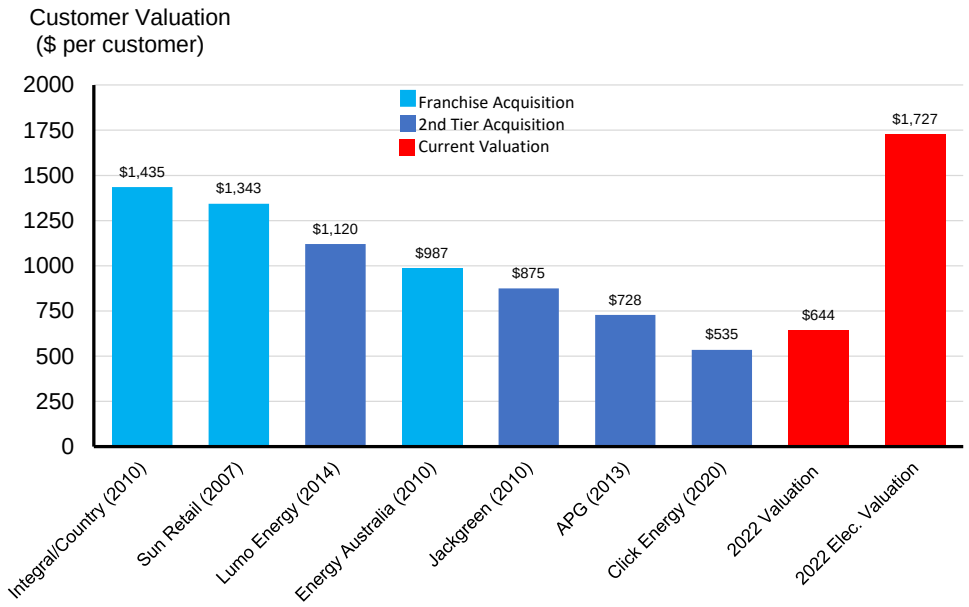
Networks are built to satisfy maximum demand occurring during hot summer evenings. The significant uptake of PV has had no meaningful impact on network peak demand, which is being driven by air conditioning installations. In fact, high solar take-up rates have increased network costs in some areas as localised congestion and voltage issues emerge in geographic pockets of concentrated solar.

11. Policy implications - impact on utilities

The impact of solar PV on energy retailers is relatively simple to calculate. During privatisation processes during the first decade of reforms, utilities would generally bid ~$1,000-$1,400 per customer (light-blue bars, Fig.18). This was based on assumptions that franchise customers were *relatively sticky* in the contestable market, and consumed ~7,000kWh per annum (7500kWh per annum in QLD). Solar PV and broader energy efficiency measures resulted in households consuming less energy from the grid with the Australian average now ~5,500kWh. In 2022, it is estimated that retail electricity customers are worth ~$644 (first red bar, Fig.18).

Prima facie, this suggests very material shareholder losses on the value of acquired retailing businesses. However, over the longer run, we believe households will invariably 'electrify'. Griffiths (2022) estimates electrification of Australian households may increase consumption from the current 5,500kWh to ~13,500kWh. If so, this would clearly reverse any current mark-to-market losses, with consumer valuations rising to $1,727 per customer (far right bar, Fig.18).

Figure 18: Customer valuations during retailer sales processes



Source: Market transactions, Griffiths (2022).

One challenge facing the conventional energy retailer is customers seeking energy independence (i.e. regardless of the cost/benefit of doing so). Third-party aggregators are also seeking to dis-intermediate retailers in order to access the flexible loads and embedded generation of end-use consumers. However, the vast majority of such resources are still managed directly or indirectly by energy retailers. Opportunities for new retailer business models, such as risk-sharing with customers

or installing and managing assets in the household in exchange for a flat fee, will no doubt emerge over time.

For generation investors in Queensland, the rise of rooftop PV has resulted in the loss of ~1500MW of plant through displacement. Using conventional metrics for base and peak plant, this equates to ~$3bn investment, or ~$200m pa in returns to equity under equilibrium conditions. However, one could argue generation investors may have been spared from potentially stranded generation investments (i.e. if investments comprised conventional plant in an environment now on a 'net zero' trajectory).

Vertically integrated retailers which have historically relied on coal plant to supply portfolio customers have seen the value of those assets decline sharply. Rooftop solar adversely impacts coal plant (vis-à-vis minimum loads) and hastens their exit. What role rooftop solar PV has played (cf. utility scale VRE) is difficult to isolate.

Finally for the regulated network utilities – there is little notable financial impact, and thus far no known episodes of stranded network assets. Queensland has two distribution network companies and regions, Energex (Southeast Queensland including the capital city of Brisbane, Gold Coast and Sunshine Coast), and Ergon Energy which services the rest of Queensland.

The Energex and Ergon networks have at times struggled to manage a higher number of, and more complex, connection applications, as well as managing new administrated, technical, and contractual structures. For networks, high production from rooftop solar has also resulted in measured voltages during peak solar periods rising to 265v (versus the old 240v standard). Energex and Ergon networks reported serious increases in customer complaints, damaged electrical appliances (e.g. garage doors, TVs) and rising insurance claims for damaged goods. Networks responded with better tools (curtailment) and the voltage standard was dropped from 240v to 230v, which provided 'headroom'.

Relatedly, transformers have experienced reverse flows – thus networks now need to lower the theoretical rated voltage more than designed due to constant operation. For example, traditionally, a 10MVA transformer could be run in overload during a critical peak event *provided* they had time to 'rest during the day' (i.e. low load operation during the day, high load operation during the evening peak). Now however, solar PV results in high load operation during the day (i.e. flows in reverse) and are therefore unable to cool down before the evening peak. Consequently, plausible maximum ratings need to be re-thought. Operations, maintenance and replacement costs have led to networks limiting new rooftop PV installations (or at least exports) in some areas, which was not well received by consumer groups.

To help manage these issues, recent national rule change proposals have opened the possibility of charging households for any solar exports – although it has been met with deep resistance[3] . While efficient, the policy proposal is deeply unpopular with participating households. In parallel, new "solar sponge" tariffs are emerging, with lower prices for consumption during daytime periods and higher prices during evening peaks. Who should pay for variations to network infrastructure, as well as the costs and benefits of advanced metering systems, remains an open question.

Planned work on the network also becomes more difficult as solar PV take-up rates rise. Energex for example could remove a network feeder from service for

[3] See for example Byrne (2022) at RenewEconomy: Here comes the sun tax for rooftop PV – and it's not alright | RenewEconomy

maintenance from 9am to 4pm without households noticing. However, in our discussions with Energex employees, complaints about feeders out-of-service rose sharply during loss of FiT payments (especially those on the 44c P-FiT).

12. Concluding remarks

Solar PV take-up rates in Queensland now exceed 40% of rooftops – the highest in the world. Rising prices and overlapping subsidies sparked the rise of rooftop solar PV, but recovery of these subsidy through hypothecated taxes applied to all electricity bills began to adversely impact non-participating households and were curtailed or abandoned. As subsidies were unwound, the market cost of installation began to fall sharply and take-up rates actually accelerated. Participating households, that is, those with a solar PV, are unambiguously better off. Non-participating households remain adversely impacted by the nature of a two-part tariff dominated by the volumetric charge – it is not an ideal structure as solar PV rises.

For utilities, we find that overall, the *financial* impact has been surprisingly mild given the scope of the transformation. Oversupplied markets and underutilised networks have been a short-term outcome. And while there is evidence that the value of individual customers have declined, in the context of the broader energy transition and decarbonisation process it may only be transient. Many utilities evolved to install, or even own and operate, rooftop solar PV systems – acknowledging that rising take-up rates were inevitable and therefore should be brought in house. Meanwhile, planned investment in fossil fuel plants were avoided, giving time for climate policy to catch up and avoiding stranded assets.

One concern with the pace of change associated with rooftop solar PV take-up rates has been the challenge for utilities, including network and market operators, to adapt. The installation of hundreds of thousands of individual systems, most with limited telemetry and few of the sophisticated controls installed on large-scale systems, is creating new challenges, many of which are still being identified. How to maintain grid stability in neighbourhoods, or entire regions, with low or negative net demand remains a work-in-progress. The operation and behaviour of large numbers of systems following a fault can also create new risks and modes of failure which may be costly to mitigate.

The rapid rise of rooftop solar PV in Queensland, while dramatic, is unlikely to be unique. Such a shift in consumer behaviour will likely be seen in any market with good solar resources. How utilities should prepare for other widescale, distributed technologies such as behind-the-meter batteries and electric vehicles, and the electrification of natural gas appliances represents the next frontier. As with the growth of rooftop solar PV, these trends have the potential to be highly beneficial to consumers and can create growth opportunities for utilities. However, as the Queensland experience demonstrates, subsidies or targets combined with rapid technology cost reductions can quickly render what were considered “high case sensitivities” obsolete.

If there is a warning from the Queensland experience, it is that care must be taken vis-à-vis non-participating households. Renters or low-income households, or those living in apartments, have constrained or no access to rooftop solar PV. They are also likely to be lagging participants with behind-the-meter batteries and electric vehicle charging infrastructure. The challenge for policymakers is to ensure facilitation policies *‘do no harm’* while helping to drive power systems towards net zero.

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