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OPTIONS FOR AN EQUITABLE DISTRIBUTED ENERGY RESOURCE FUTURE

A DISCUSSION PAPER

ST VINCENT DE PAUL SOCIETY VICTORIA INC,
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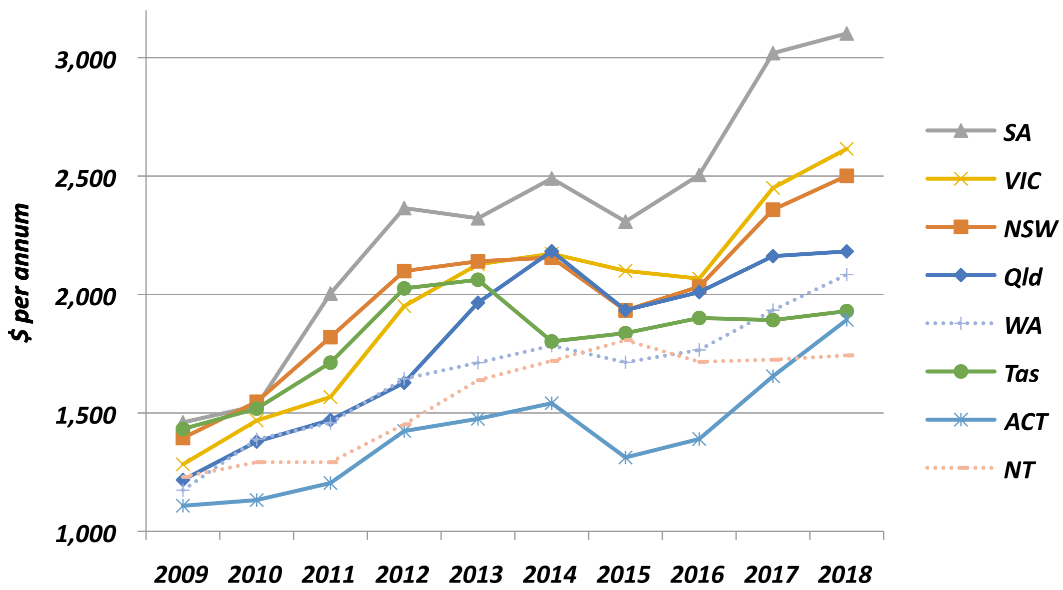
CONTACT: GAVIN DUFTY
MANAGER, SOCIAL POLICY UNIT VICTORIA
ST VINCENT DE PAUL SOCIETY
PHONE: 03 9895 5816 OR 0439 357 129

1. The problem: The inequity of Distributed Energy Resources (DER) policies and regulation

Between 2009 and 2018 nominal electricity prices increased by over 100% in South Australia and Victoria for household customers. In Queensland, NSW and the ACT they increased by more than 70%. In Tasmania, the overall increase has been 35%, much lower than their mainland counterparts due to some price decreases after 2013.

Chart 1 shows electricity bills as annual bills for households consuming 6,000 kWh/annum from 2009 to 2018. It shows that the annual electricity bill for households with this consumption level has risen by $1,640 (or 112%) in South Australia, $1,330 (or 104%) in Victoria, $1,110 (or 79%) in NSW, $965 (or 79%) in Queensland, $785 (or 71%) in the ACT and $500 (or 35%) in Tasmania.

***Chart 1** Electricity bills as annual bills for a household consuming 6,000 kWh/annum from 2009 to 2018, standing offers, single rate, GST inclusive (nominal)*[1]



Simultaneously, state and federal governments have introduced policies and programs that promote and subsidise the uptake of rooftop solar,[2] and an immediate slow-down in this respect seems unlikely. As recently noted in by a solar industry blog:

> ***"2019 will be another positive year for solar rebates across Australia.***
>
> ***The STC value remains high, and the feds aren't likely to abolish the STC this coming year.***

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[1] This chart was first presented in St Vincent de Paul Society and Alviss Consulting, The NEM – No "guarantee' for consumers, Observations from the Vinnies' Tariff-Tracking Project, October 2018
[2] For example, the Small-Scale Renewable Energy Scheme (SRES), Victorian Solar Homes, The NSW Solar Bonus Scheme (closed), Adelaide Sustainability Incentives Scheme, ACT Solar for low income program

> ***A Federal Labour win will see a new battery rebate hit the solar market, should the Labour party win and keep their promise.***
>
> ***South Australians, ACT residents and Victorians can look forward to even greater rebate benefits as their governments appear to be more solar incentive pro-active.***
>
> ***Coupled with the STCs from the feds, residents of these states can look forward to a potential rebate double dip."[3]***

Chart 2 below shows the number of monthly small-scale solar installations in NSW/ACT, Victoria, Queensland and South Australia from January 2018 to May 2019. In regards to Victoria, the shows that the monthly rate of new solar installations was around 3,000 before the Victorian Government's Solar Homes program launched in late August 2018.[4] Post the rebate taking effect, the number of solar installations doubled (although slowing down during the holiday season) before nose-diving in April 2019 when the program was fully subscribed for the 2018/19 financial year, and no further applications were accepted.

***Chart 2** Small scale solar installations by month, January 2018 to May 2019[5]*

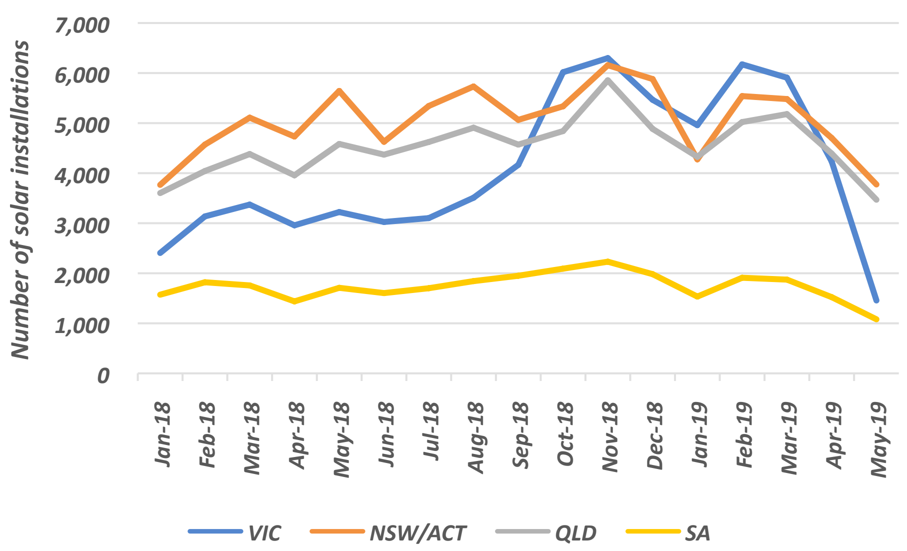
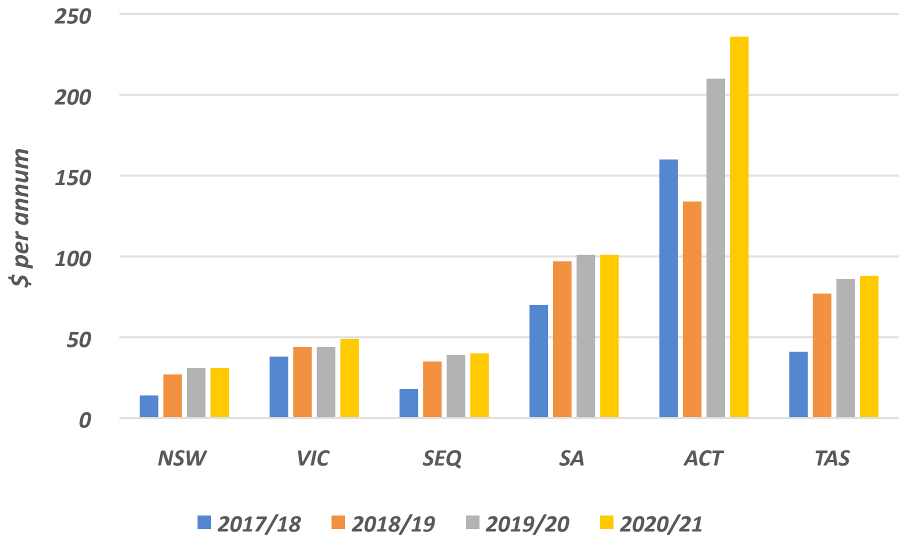


Chart 3 shows the estimated annual cost of the Small-Scale Renewable Energy Scheme (SRES) and Feed-in Tariff (FiT) subsidies on households consuming 6,000 kWh/annum.[6] The ACT has the highest SRES and FiT costs in the country. In 2019/20, these two components are estimated to cost a typical household $210 per annum (up from $134 in 2018/19). The ACT Utilities Concession reduces bills for concession cardholders, and while it is set to increase from 1 July 2019, its increase of $46 per annum (to the annual amount of $700)

[3] See https://instylesolar.com/blog/2018/12/05/2019-solar-battery-rebates/
[4] See https://www.premier.vic.gov.au/thousands-of-victorian-homes-save-millions-on-solar/
[5] Based on small generation unit installation data available from the Clean Energy Regulator (CER) at http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations
[6] AEMC, 2018 Residential Electricity Price Trends, Databook (EPR0064) available at https://www.aemc.gov.au/market-reviews-advice/residential-electricity-price-trends-2018

does not cover the increases households are expected to see from the SRES and FiT components of $76.[7] In South Australia, where the SRES and FiT costs are estimated to be $100 in 2019/20 per household, the annual electricity concession is currently (2018/19) $223.01[8] per annum meaning that the cost of the SRES and the FIT almost makes up 45% of the total concession.

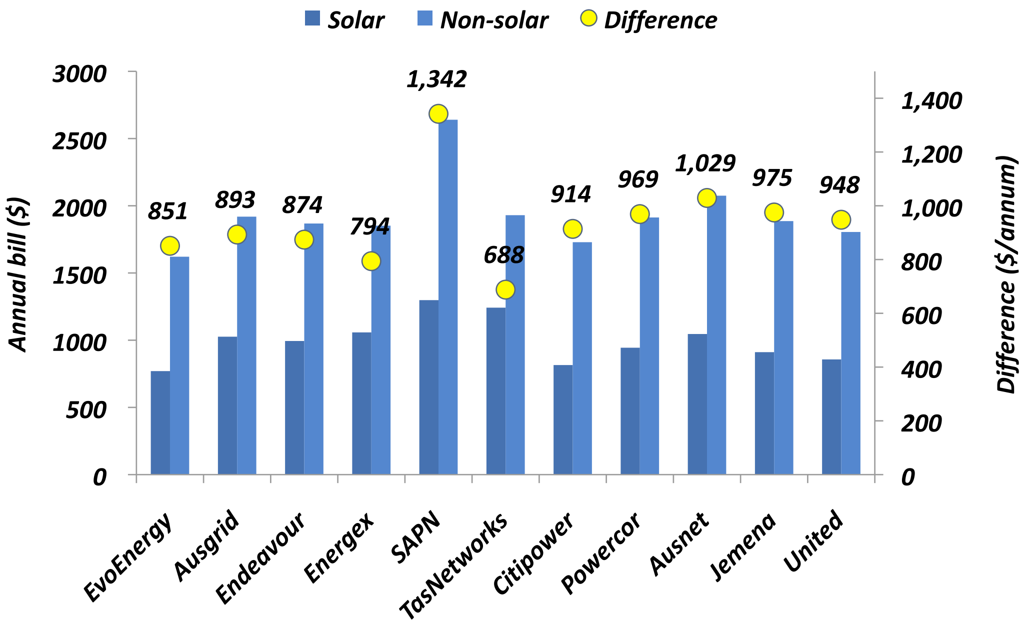
***Chart 3** Annual costs of SRES and FiT for a household consuming 6,000 kWh/annum from 2017/18 to 2020/21*



As of July 2018, the difference in the annual bill between solar (using 6,000 kWh/annum and having a 3kW system installed) and non-solar households (using 6,000 kWh/annum) was from $690 in Tasmania to $1,340 in South Australia (see chart 4 below).

[7] See https://www.revenue.act.gov.au/community-assistance/utilities-concession
[8] See https://www.sa.gov.au/topics/care-and-support/financial-support/concessions/energy-bill-concessions

***Chart 4** Household electricity bills as annual bills for solar and non-solar households consuming 6,000 kWh/annum as of July 2018, market offers inclusive of discounts, single rate, GST inclusive (solar households with 3kW installed)*[9]



A mix of uncoordinated policies, designed to increase PV take-up, and insufficient concessions for the vulnerable is not a sustainable approach to Distributed Energy Resources (DER). While we are highly supportive of DER and the numerous benefits it can deliver in regards to energy affordability, reliability and a reduction in emissions, it needs to be rolled out in a more equitable manner. The Australian Energy Network Association's Electricity Network Transformation Roadmap (ENTR) has projected that more than 40% of energy customers will use DER by 2027, and more than 60% by 2050.[10] St Vincent de Paul Society is therefore extremely concerned about the impact DER will have on energy affordability for non-DER users, given the negative impacts to vulnerable customers that have already been observed, and the projection that this will only become more pronounced. This affordability problem will manifest in two ways, (1) Energy being relatively more expensive for non-DER participants, and (2) Non-DER participants being required to pay more for grid upgrades and/or cross-subsidise DER participants use of infrastructure, more so than the net benefits that DER participants give to Non-DER participants.

In our view, we cannot move forward with DER policies and market designs that may further split the community into an energy underclass and an energy upper-class, as Transmission and distribution network cost are reallocated to benefit one group at the expense of another. We already have a stark divide between asset rich and asset poor in relation to homeownership in Australia and as most DER technology is asset driven (a

[9] The average market and solar offer bills in this chart are based on all retailers with an offer in each network area. This chart was first presented in St Vincent de Paul Society and Alviss Consulting, The NEM – No "guarantee' for consumers, Observations from the Vinnies' Tariff-Tracking Project, October 2018
[10] CSIRO and Energy Networks Australia, The Electricity Network Transformation Roadmap, Final report, April 2017

house for rooftop solar, land for microturbines or electric vehicles that can be used for storage) we need to be mindful of how current DER policies may shape future inequities in relation to energy affordability and access.

The St Vincent de Paul Society Victoria is of the view that the National Electricity Rules (NER, Rules) must ensure that the direct beneficiaries of DER also directly contribute to the use of and upgrades to electricity networks required to deliver the benefits that DER unlocks. The Rules should enable a pricing framework that delivers equitable outcomes for various customer groups, promotes the uptake of DER, and encourages the release of new technologies and services to support consumer decisions and choices in the energy market as it evolves.

This paper focuses on what the Rules and the network pricing framework should deliver to promote equitable consumer outcomes.

2. Challenges arising from DER

Enabling high DER penetration, and unlocking the benefits DER provides, presents technical challenges as well as additional costs to the energy system. The proliferation of DER is not only an issue for the distribution networks as it also creates challenges for the transmission system and the ability of the market operator to maintain system security.

2.1 Transmission issues

Several market bodies have been involved in addressing DER challenges for the transmission system. The Energy Security Board (EBS) has been tasked with working on future market design.[11] The Australian Energy Market Operator (AEMO) has developed the Integrated System Plan (ISP) which has "modelled and outlined targeted investment portfolios that can minimise total resource costs, support consumer value, and provide system access to the least-cost supply resources over the next 20 years to facilitate the smooth transition of Australia's evolving power system".[12] The ISP also identifies a number of highly valuable renewable energy zones (REZ) across the NEM, while the Australian Energy Market Commission (AEMC) is currently working on the coordination of generation and transmission investment (the COGATI review).[13]

All these workstreams contend with the issue of who pays for what service. A benefit test is being used to model who benefits (e.g. consumers, generators or government) from allowing generators firm access to the transmission system.

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[11] See http://www.coagenergycouncil.gov.au/publications/post-2025-market-design-national-electricity-market-nem
[12] See AEMO, Integrated System Plan, For the National electricity Market (NEM), July 2018, 3 at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Integrated-System-Plan-2018_final.pdf
[13] See https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and

As these workstreams address the transitioning of the energy system, similar conversations are needed for the sub-transmission level. In our view, the sub-transmission level is based on a similar framework, and the same benefit tests used for firm access to the transmission system may be suitably applied to DER participants and firm access to the distribution network.

2.2 Distribution issues

A high uptake of DER technologies can create voltage issues as well as network congestion. Regulations stipulate that distribution networks must maintain network voltages within a set range as spikes on low voltage lines can damage the network as well as consumers' equipment.

We have sought information from the network businesses about the magnitude of the problem DER currently presents for network stability, and while all those who responded to our request have detected issues, they did not have high-quality data that they could share at this point. Furthermore, they all stressed that while DER is already presenting issues for network stability, the focus is on solutions to integrate a greater uptake of DER in the future. As such, the challenge is to ensure that there are efficient network-wide solutions to deal with a high uptake of DER.

While there are various ways the network businesses could seek to improve management of voltage issues as well as network congestion, the key issue, from our point of view, is that all remedies will come at an additional cost.

As the cost of DER technologies such as rooftop solar is likely to decrease, we can expect to see an increase in uptake, both in terms of the number of installations and the size of the systems installed. We, therefore, need to create a framework that can address these issues in the long run.

Increased uptake in DER technologies should be a positive development, however as some consumers will be unable to participate a sustainable framework must ensure that not everyone pays the same when the greatest benefits are returned to some. To date, no such framework exists, but rather the opposite has arisen as noted above in section 1.

3. Status quo: Inverters tripping and constraining injections

Currently, solar system inverters trip if there are voltage issues. This means that the amount of electricity generated is reduced and that the solar system is delivering below its capacity. Many solar system owners may not register that the inverter has been tripping while others will notice that their electricity generation is reduced as they forego earnings from the feed-in-tariff (FIT) that the exported energy otherwise would have attracted.

Energy networks can also constrain export from solar generation if there are congestion or voltage issues. Most networks do only allow automatic connection of solar systems up to

a maximum size (e.g. 5 kW) while systems larger than the maximum threshold will be assessed on a case by case basis to ensure that the local network conditions can incorporate the system. This process is lengthier than an automatic connection and can involve additional costs.

Households in rural areas also typically face more constraints than urban households. In the Essential Network in NSW, for example, there is an automatic connection for rooftop solar systems of up to 5 kW in urban areas while the threshold in rural areas is 3 kW.

The AEMC views export limits as a blunt approach to network issues arising from DER. The AEMC has stated: "Restricting export is unlikely to be efficient or meet consumers' expectations. Where this restriction applies only to consumers who are connecting to the network at a later time, this raises issues of equity and is likely to be inconsistent with the 'open access' nature of the regulatory regime".[14]

It is clear that the current arrangements are sub-optimal for both DER participants and society more broadly as renewable energy can fail to be harvested despite the investments that have been made. If the level of inverters tripping was to increase, we are also likely to see an increase in complaints to networks and retailers, which again increases the cost of supply to all consumers. Furthermore, there are inequities between urban and rural DER participants.

It has been broadly recognised that there is no "silver bullet" to efficiently integrate a high penetration of DER into the networks, and there are likely to be a suite of measures required.[15] A key issue is, therefore, to ensure that DER participants (and thus direct beneficiaries of DER integration) pay their fair share for the measures implemented.

We realise that there are many low-income consumers that have been, and will continue to be, direct DER participants and that some will struggle to afford additional costs. Conversely, there are many low-income consumers that are unable to be direct DER participants, and who are therefore unable to reduce their energy costs or afford additional costs. Just because the additional cost is lower, per household, when smeared across all consumers does not mean it is more equitable, or affordable, than allocating additional costs to those directly participating in, and benefiting from, DER.

4. Proposed solutions

4.1 Network upgrades

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[14] AEMC, Economic Regulatory Framework Review, Promoting Efficient Investment in the Grid of the Future, July 2018, xi

[15] See, for example, AEMO, Technical integration of Distributed Energy Resources, A report and consultation paper, April 2019, Distributed Energy Integration Program (DEIP), Overview/DEIP at a glance, February 2019, Australian Energy Networks Association, Embedded Generation Project, Final Report, Marchment Hill Consulting November 2015 and the AEMC's forward looking work program at https://www.aemc.gov.au/our-work/our-forward-looking-work-program/system-security/lower-emissions

Network improvements such as pole and line replacements, network augmentation, including new substations, and 'flexible grid' technology to monitor and control networks in real-time are all capital expenditure projects that the networks are likely to consider.[16] *The networks have, however, been accused of an 'expenditure bias'*[17] *towards capital expenditure (capex) and the above improvements would be largely capex based. While analysis undertaken by the AEMC was unable to produce conclusive evidence that the networks' investment decisions exhibit a bias towards capex, it also noted that incentives are strongly biased towards capex if the networks expect to source funds at a rate lower than the regulated rate of return.*[18] *In relation to DER, the AEMC noted:*

> *"[T]he Australian electricity system is likely to be more decentralised in the future, and DER are likely to be able to provide plausible alternatives to traditional network solutions. The Commission is concerned that the potential for bias would be greater under such a scenario, especially when combined with a high interest rate environment.*
>
> *Separate operating and capital expenditure assessment and remuneration is not likely to be suitable for a future with high DER penetration"*[19]

We have seen modelling undertaken by various networks that propose DER solutions that will cost consumers well under $10 per annum, and while opex solutions may be less expensive for consumers in the long run than capex solutions, we are strongly opposed to the costs being allocated under standard network expenditure method only.[20]

4.2 Connection charges

The Rules currently allow networks to charge a connection charge for solar exporters, and this is most often determined by inverter size. While we recognise that a connection charge can recover costs from active DER participants, it is a blunt instrument. A connection charge does not give DER participants options, or incentives, to change self-consumption, install batteries or engage third parties in managing electricity export. Similar to the traditional fixed supply charge, a connection charge can work as a simple cost recovery tool, but it does not provide the dynamic / temporal price signals over time required for an efficient DER future.

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[16] See, for example, Powercor's Draft Proposal for the 2021-2025 Regulatory Reset, 18 at https://talkingelectricity.com.au/wp/wp-content/uploads/2019/02/Powercor-Draft-Proposal-2021-2025.pdf

[17] Both the Finkel report and the AEMC's Economic Regulatory Framework Review (July 2018) discuss stakeholders' concerns about the networks' 'expenditure bias'. See AEMC report at https://www.aemc.gov.au/sites/default/files/2018-07/Final%20Report.pdf

[18] AEMC, Economic Regulatory Framework Review, Promoting Efficient Investment in the Grid of the Future, July 2018, viii

[19] AEMC, Economic Regulatory Framework Review, Promoting Efficient Investment in the Grid of the Future, July 2018, ix

[20] The modelling of network investments required were based on three options (where option 1 is the most expensive and option 3 the least expensive): 1) All customers can export up to 5kW at all times, 2) All customers can export up to 5kW most of the time, and 3) Most customers can export up to 5kW most of the time. From Powercor, Citipower and United Energy, Building the network of the future, Slide pack, April 2019

4.3 Institutional views and processes

The AEMO published an Integrated System Plan (ISP) for the National Electricity Market (NEM) in July 2018 which noted that it would be important to coordinate DER to capture the benefits it can provide to market and system operations. AEMO stated: "Enabling DER to respond to both market and network signals could also deliver financial savings to consumers".[21] In terms of next steps, AEMO noted that they would continue to "investigate the requirement for increased coordination of DER, the infrastructure to support and integrate those resources, and their impact on the operation and cost of the distribution system."[22]

For the AEMC's 2018 regulatory framework review, the terms of reference directed the AEMC to examine the impact an increasing penetration of DER will have on the economic regulatory framework. The review, therefore, focused on "the distribution level and considered whether changes are required to the economic regulatory framework to support the continuation of the electricity sector's transformation".[23]

While the AEMC acknowledged that the future model for efficient integration of DER is uncertain, it identified and discussed various *static* ***and*** *dynamic* ***strategies that the distribution networks can utilise to manage an increase in DER penetration.***

Static strategies that can be implemented in the short term to address, albeit with limitation, economic and technical issues arising from DER include:

- ***Cost reflective network tariffs to incentivise consumers to use the network more flexibly***
- ***Using network connection agreements to introduce export limits on solar systems***
- ***Adopting power management strategies (i.e. rebalancing low voltage phase connections and close monitoring of the low voltage network).[24]***

Due to the limitations posed by static strategies in the medium to long term, the AEMC is recommending more dynamic strategies to be adopted. Initial steps to be adopted by the network businesses include:

- ***To develop a better understanding of the impact a higher level of DER penetration will have on their networks and the constraints, it will place on their low voltage network (e.g. concerning voltage limits)***
- ***To quantify and publicise the DER hosting capacity of their networks.***

It is typically difficult for external parties, consumers as well as regulators, to ascertain the extent of a problem flagged by a distribution business and the solutions that may be

[21] AEMO, Integrated System Plan, For the National Electricity Market (NEM), July 2018, 66 at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Integrated-System-Plan-2018_final.pdf
[22] Ibid, 99
[23] AEMC, Economic Regulatory Framework Review, Promoting Efficient Investment in the Grid of the Future, July 2018, iv
[24] Ibid, x

required. The network businesses know their networks best, but they may also have an incentive to overestimate problems and/or favour certain solutions over others. As such, we recommend that the distribution networks need to closely monitor and publicly report on the impact DER has on the networks.

Furthermore, as the transformation will in all likelihood require network expenditure (whether it is in the form of capex or opex), we recommend the time is right to add another aspect to this discussion. Who should pay for and how are these costs allocate when enabling of a higher DER uptake?

5. Approaches that open up for DER participants paying their fair share

The below discusses two options that can ensure that DER participants contribute to the expenditure in the short and medium-term.

5.1 Require networks to charge generators for using networks

This option would require a change to Rule 6.1.4 (a) which currently prohibits networks from charging DER participants Distribution Use of System (DUOS) charges.

> *"A Distribution Network Service Provider must not charge a Distribution Network User distribution use of system charges for the export of electricity generated by the user into the distribution network."*[25]

The Rule was created with a one-way flow of electricity (from generators to consumers) in mind and at a time when the uptake of DER was negligible, while DER has opened up for two-way flows. In our view, there is, therefore, a mismatch between the prevalent and growing two-way flow of energy currently taking place and the antiquated one-way charge for using the system.

If the networks were required to charge DER participants a charge per kWh for DER exported back via the grid, this revenue could be used to upgrade networks to limit constraints and enable future DER penetration.

Importantly, we are not necessarily advocating for an approach where DER participants have to pay for using the networks. Rather we are proposing to explore a solution that allows DER generators to choose between paying or being constrained. This is an important distinction as some DER participants may prefer being constrained rather than paying a DUOS charge for export.

For example, if a network experiences congestion on a specific zone-substation, it can set a DER export price for that specific zone-substation. The generating consumer would then determine whether they would a) accept constraints, b) accept the cost of the export or c)

[25] National Electricity Rules, 6.1.4 at https://www.aemc.gov.au/sites/default/files/content//NER-v66-Chapter-06.PDF

explore other options such as batteries and coordinated export reductions (including the involvement of 3rd party services).

Naturally, the cost of injecting energy into the network will vary significantly between locations and, to enable cost reflective pricing, a nodal DUOS export charge would be required.

Nodal DUOS export pricing is a price put on the table for connections to the network (households) and third parties to take up where they choose instead of being constrained or have other intervention applied.

The level of constraints differs significantly from sub-station to sub-station. In Victoria's Powercor network, for example, solar is currently constrained almost 20% of the time in Drysdale (the DDL sub-station) near Geelong on the Bellarine Peninsula while it is constrained less than 5% of the time in Corio (the CRO sub-station) east of Geelong.[26] This is not a case of one size fits all, and to promote cost-reflective price signals, nodal pricing for exports would be necessary.

We acknowledge that this may be considered inequitable as some DER participants will be offered a lower export DUOS than others, however, the suitability of the location and available infrastructure should be an issue to consider for small-scale DER participants just like it should be for larger-scale generators. As highlighted in the AEMC's Coordination of Generation and Transmission Investment (COGATI) report:

> ***"Currently, there is a significant amount of generation capacity that is seeking to connect to the network. Private sector investors are planning generation where transmission has limited or no capacity to connect it. This is not sustainable and is increasing costs in the sector. Given that a significant amount of this new capacity is seeking to locate at edges of the network, there is an increasing need to invest in and build transmission to reliably connect generators".[27]***

Similar to the principle expressed by the AEMC concerning COGATI ("Building transmission to benefit generators, means that generators should pay for this transmission investment"[28]), we believe upgrading distribution networks to benefit DER participants means that DER participants should pay for this network investment.[29]Conversely where non DER customer are deriving a benefit from DER participants they should pay for these benefits.

[26] Powercor, Citipower and United Energy, Placemat, Solar enablement, 7 August 2019
[27] AEMC, Coordination of Generation and Transmission Investment, Final report, December 2018, vii
[28] Ibid.
[29] Note that we are not necessarily endorsing the AEMC's proposed solutions in the COGATI report. These references merely reflect the similarity of issues and principles relevant to large scale generators and transmission systems as well as small scale generators and distribution networks.

Networks are currently modelling costs and benefits of enabling future solar uptake. Their options, however, are largely indifferent to individual customer preferences. Rather, the networks are exploring costs and benefits from constraining, network investments and dynamic controls on substation levels.

While we acknowledge that networks require, or at least strongly prefer, revenue certainty and that individual customer decisions do not offer the same certainty as regulated cost recovery, the networks can undertake modelling of nodal DUOS charges for export as well as take-up rates to project revenue.

As the networks seem prepared to work with individual customers where removing constraints is regarded infeasible (from a cost-benefit perspective) by exploring battery storage options, coordinated export reductions and Flexible Grid initiatives, they should also be able to develop and offer individual customers a nodal DUOS export charge.

Furthermore, we believe the market design should encourage and enable energy management services. A high DER penetration future is likely to operate more efficiently if there are opportunities for energy management services to develop solutions that can benefit DER participants as well as the networks. Importantly, a DUOS charge for export will produce a price signal that can incentivise DER participants to engage with such energy management services.

As highlighted in a report by Marchment Hill Consulting for the Energy Networks Australia, networks can develop partnerships with technology and service providers, as well as retailers, to pursue DER opportunities and solutions.[30] The report states:

> ***"Partnerships will be crucial to ensure that customer are presented with persuasive product offers that promote mutually beneficial EG outcomes. Bundling of product and pricing offers to minimise the impact on customers from the introduction of new tariff structures (e.g. maximum demand tariffs), while at the same time supporting efficient operation of EG to maximise its benefits, will be crucial under a future market state with high levels of EG."[31]***

Other parties, such as local governments, may also wish to be involved. Local governments can, for example, offer ratepayers storage options to avoid these charges. This would complement the policies in place where local governments are pursuing decarbonisation strategies.[32]

5.2 Reflect the cost of network export in the Feed-in-Tariff

[30] The report acknowledges current regulatory and policy barriers that provide a disincentive for networks to pursue this approach.
[31] NSP refers to Network Service Providers and EG refers to Embedded Generation. See Energy Networks Association, Embedded Generation Project, Final Report, Marchment Hill Consulting November 2015, 235
[32] The Greenhouse Alliances, for example, are formal formal partnerships of local governments driving climate change action across 70 of Victoria's municipalities. See www.victoriangreenhousealliances.org

DER participants typically receive a Feed-in-Tariff (FiT) for electricity exported. Currently, DER participants may receive a premium FiT (paid by the electricity distribution business and its cost recovered from all customers) or a retailer FiT. The retail FiT can be regulated or non-regulated. In Victoria, the Essential Services Commission (ESC) sets a minimum retail FiT for every financial year. In determining the minimum FiT rate the ESC takes the following approach:

> ***"Calculating the minimum FiTs requires us to estimate prices retailers avoid paying on wholesale electricity purchases when a small scale generator exports electricity to the grid… Other costs are also included in the FiT. These are the avoided:***
>
> - ***cost of market fees and ancillary service charges***
> - ***value of distribution and transmission losses***
> - ***value of the social cost of carbon"[33]***

The ESC does not have the mandate to take broader policy objectives, such as promoting the uptake of rooftop solar, into account when setting the minimum FiT rate.[34]

A FiT rate is a potential tool that could be used to ensure that DER participants contribute directly to network-related solar enabling solutions. In the case of the ESC's determination, the minimum FiT would then have to be determined based on:

- ***Minimum FiT = (Avoided wholesale price + Avoided fees and charges + Avoided network losses + Avoided social cost of carbon) – (Cost of distributing export).***

The cost of distributing export would then be network revenue to be allocated towards solar enablement projects. In jurisdictions where the FiT rate is not regulated, the electricity distribution business would propose the 'cost of distributing export' rate.

As there are significant differences between distribution networks in terms of the challenges, and costs, they face to enabling an increasing uptake of rooftop solar, the minimum retail FiT should vary between the distribution networks. Due to the complexity, it would add to retail offers (and thus the risk of reduced retail market comparability). However, we do not envisage nodal network pricing to be applied through this model.

Furthermore, we note that a network cost applied to the FiT rate does not have to be a mandatory solution applied to all DER participants. DER participants accepting a reduced FiT rate in exchange for not being constrained can still sign a contract with their electricity distribution business.

6. Broader benefits and challenges

The solutions proposed in this paper are not aimed at penalising households with rooftop solar installed. We recognise that these households have made investment decisions

[33] ESC, Minimum electricity feed-in tariffs to apply from 1 July 2019, 2
[34] ESC, Minimum electricity feed-in tariffs to apply from 1 July 2019, 13

based on the information (and in some cases, subsidies) made available to them. We are, however, of the view that consecutive governments' policies promoting the uptake of rooftop solar have created an imbalance in favour of solar and, potentially, at the disadvantage of other technologies, such as storage. If these policies continue, the network problem is likely to exacerbate. Furthermore, there is evidence (see section 1) to suggest these policies have come at the cost of vulnerable customers.

DER is central to a lower emissions energy future, and it is therefore imperative that we can achieve a high DER penetration without allowing electricity to become inexpensive for some and unaffordable for others. Inefficient and inequitable allocations of costs and benefits will not deliver the desired outcomes in the long run.

Non-DER participants have already subsidised this initial shift to a DER future, and while this has incentivised the DER uptake, largely in the form of rooftop solar, this does not justify ongoing subsidies from non-DER participants to DER participants into the future. Rather, we need to deliver price signals that can incentivise DER participants to engage with energy management services as well as other technologies, such as storage, to deliver a sustainable DER future.

We, therefore, recommend:

- ***that serious consideration is given to a rule change proposal for Rule 6.1.4.; and***
- ***The Tariff Structure Statement introduces efficient network pricing signals for DER customer exporting to electricity distribution networks.***