Clean Energy Council submission to the New South Wales Department of Planning, Industry and Environment Consultation Paper: Promoting Innovation for NSW Energy Customers

The Clean Energy Council (CEC) welcomes the opportunity to provide feedback on the New South Wales (NSW) Government Department of Planning, Industry and Environment (DPIE) Consultation Paper *Promoting Innovation for NSW Energy Customers*.

The CEC is the peak body for the clean energy industry in Australia. We represent and work with Australia's leading renewable energy and energy storage businesses, as well as accredited designers and installers of solar and battery systems, to further the development of clean energy in Australia. We are committed to accelerating the transformation of Australia's energy system to one that is smarter and cleaner.

We have worked in collaboration with the Electric Vehicle Council (EVC) to develop an agreed response to the issues with respect to electric vehicles. The EVC is the peak body in Australia representing the interests of manufacturers and suppliers of EV charging equipment, software service providers in the field of EV charging orchestration, and electric vehicle manufacturers.

The NSW Government has an important role to play in energy market reform, particularly in the areas where reforms undertaken by the Australian Energy Market Commission (AEMC) have failed. There are significant opportunities for improvement in energy policy, especially as it relates to smart electricity meters and stand-alone power system (SAPS) reforms. These are two areas of energy policy where the AEMC has failed to deliver adequate policy. Indeed, the AEMC reforms have become the main barrier to progress in these two areas.

We would support moves by NSW to derogate from the national framework to allow distribution network service providers (DNSPs) to own and operate generation assets for SAPS and to include these assets in their Regulated Asset Base (RAB).

We would be happy to discuss these issues in further detail with representatives of DPIE. We look forward to contributing further to the development and implementation of this important area for energy policy.

Smart Electricity Meters

The Power of Choice *Competition in metering* reforms have been a major disappointment. The metering rollout is too slow. Consumers are paying for the smart meter rollout without realising the smart meter benefits due to difficulties with data accessibility.

The failure of metering policy in the National Electricity Market (NEM) undermines the prospects for other important reform initiatives, including tariff reform, improving network visibility, and increasing hosting capacity cost effectively.

The AEMC has acknowledged that:

- Outside of Victoria smart meter penetration is about 25% and, at the current rate, full deployment will not be achieved until the 2040s,
- The rollout of smart meters in the NEM has been largely driven by installation of solar PV systems or by new connections. Rollouts initiated by retailers “have been minimal at most”, and
- Current arrangements for negotiating and utilizing data that the meter can provide are inefficient and likely not contributing to the long-term interests of consumers.

The AEMC review of metering services must, at a minimum:

- Ensure that smart meter data is available to consumers (and their authorised representatives),
- Speed up the rollout, and
- Make power quality data available to DNSPs.

If the AEMC fails to make these reforms in 2022 the NSW Government should seriously consider derogating from the NEM metering framework and addressing the problems itself.

Stand-Alone Power Systems

The AEMC’s proposed ‘NEM consistency’ service delivery model is unnecessarily complicated and cumbersome for individual power systems. CEC strongly prefers an ‘integrated service delivery model’, which would involve:

- DNSPs using individual power systems to supply electricity to existing customers wherever that would be cheaper, safer, and more reliable than traditional poles and wires,
- Enforceable standards for reliability and safety,
- Regulatory oversight of prices, and
- Universal access to dispute resolution processes.

The AEMC’s proposed pricing model overcomplicates pricing for SAPS. There is no need or benefit in structuring pricing for SAPS customers so that it reflects costs to supply through the National Electricity Market (NEM). Pricing to customers supplied by SAPS should reflect the cost to supply them, rather than the costs on the NEM.

The exemption cap for generation assets is arbitrary. DNSPs should be allowed to own the generation component of individual power systems used for regulated supply of electricity. Concerns regarding the impact on competition would be better addressed through a framework of regular reporting and review.

We support the proposal for NSW to work with the AER to reclassify SAPS generation through the Framework and Approach process, including classification of specific SAPS services (e.g. fault repair and maintenance to generation assets) as part of a distribution service. We would also support moves by NSW to derogate from the national framework to allow DNSPs to own and operate generation assets and include these assets in their RAB.

Responses to Questions Raised in the Consultation Paper

We have replied directly to the questions in the Consultation Paper that are most relevant to the CEC and its members. We have indicated where the question is either not directly relevant to CEC and its members or where we do not believe we are well placed to provide the information requested.

1a. How are the costs and benefits of smart meter installations currently communicated to customers?

There is very little communication by electricity retailers to customers regarding the costs and benefits of smart meter installations. In its review of metering services, the AEMC has acknowledged that the rollout of smart meters in the NEM has been largely driven by installation of solar PV systems or by new connections and rollouts initiated by retailers "have been minimal at most". According to DNSPs, "retailer or customer led roll outs are in many respects non-existent".

The smart meter rollout is being driven by compulsion, not incentives. The compulsion is in the wrong place. The compulsion sits with owners of new connections and new DER systems. This accounts for more than 60% of new smart meter connections. More than a third of new smart meters are being paid for by customers who are required to as a condition of connecting DER. Very few customers request a smart meter because they want a smart meter per se. They request a smart meter because it is a mandatory requirement of a new connection or for installation of DER.

The private benefits of a smart meter can be better accessed using alternatives provided by inverter suppliers or companies such as Solar Analytics. A customer does not need a smart meter to obtain the private benefits associated with them. However, consumers who have a smart meter should be provided with access to its data. For smart meters to deliver real benefits to consumers the data needs to be able to be automatically and digitally accessed by authorised third parties.

1b. Can electricity retailers provide government with the various cost inputs for smart meters (this information will be treated as commercial in confidence)?

CEC does not have access to the commercial in confidence information being requested and will leave it to electricity retailers to provide this to the NSW Government. We would urge DPIE to publish this data (anonymised and within the constraints of commercial confidentiality). Consumers are paying for the meters, so it is reasonable to expect that they should have some understanding of what they are paying for.

We would recommend that DPIE obtain cost inputs for retailers in Victoria as well as NSW. This would enable benchmarking of the capital and operating costs for use of mobile carrier telecommunications services against radio frequency (RF) mesh networks.

1c. Would it be useful for customers if the cost of a smart meter was included on the details of electricity plans on comparison sites?

Yes. Greater transparency regarding the cost of a smart meter would enable customers to make more informed choices.

1d. What share of customers are on cost reflective pricing tariff options?

CEC does not have access to data regarding the proportion of NSW customers on cost-reflective tariffs. Nevertheless, we know that:

- All customers on cost-reflective tariffs have a smart meter, and
- Almost all customers with a smart meter were required to install it either because they installed a solar PV system, or they were a new connection.

The current approach to the smart meter rollout and tariff reform is inequitable. The requirement to install a smart meter is being selectively imposed on customers who install a solar PV system or are a new connection. To make matters worse, cost-reflective tariffs are being imposed selectively on customers with smart meters. This discourages customers from obtaining a smart meter. As the AEMC has acknowledged, concerns over tariff reassignment are a disincentive to request a smart meter.

It is important to recognise that smart meters and cost reflective tariffs are generally unpopular and inconvenient and most customers only take up a smart meter or a cost reflective tariff when they are required to. The regulatory framework should not single out a relatively small group of customers for the mandatory smart meters and cost reflective tariffs. CEC members report that their customers strongly prefer simplicity over full cost reflectivity – even when a cost reflective tariff could save them money.

1e. What are the benefits and challenges of customers moving onto cost reflective tariffs?

As penetration of rooftop solar PV systems increases, solar energy will become increasingly abundant during daylight hours. Customers should be encouraged to shift their load to daylight hours to utilise the cheap and abundant solar energy available. Time-of-use tariffs are one way to encourage load shifting to daylight hours. However, using the installation of a smart meter as the trigger for tariff reassignment is counter-productive because it is a disincentive for smart meter uptake.

Policy makers should recognise that most customers do not want smart meters and cost-reflective tariffs and it is a false premise to assume they will be enthusiastically adopted by customers. It is more realistic to assume that most customers do not want a smart meter or a cost-reflective tariff and, generally, will only adopt them when they are required to. Few customers want their life to be made more complicated by having to deal with more complex electricity tariffs. This is particularly so for demand-based tariffs, which customers find difficult to understand and use to their advantage.

Published evidence suggests that cost-reflective tariffs do not make a material difference to customer behaviour. Customers quickly tire of tariff-induced behaviour change. They are only attractive to customers if there is an intermediary (e.g. energy retailer or third party) who can handle the complexity on the customer’s behalf. To ensure the success of cost-reflective tariffs they should be introduced alongside home energy management system (HEMS) technology so that customers can program their appliances to automatically respond to price signals with a minimal ‘set and forget’ approach. A HEMS that controls major appliances is the same technology that would enable dynamic export limiting of DER.

1f. Are there any other costs to customers that should be considered?

DPIE should consider ways to reduce the cost of smart metering to improve the benefit / cost ratio for consumers. Some ways to achieve this include:

- The greatest cost savings for smart meters can be achieved through leveraging economies of scale, which are not achievable under the current one-by-one installation approach by retailers. A mandated area-by-area approach would introduce significant economies of scale, most notably reducing travel times for installers and the need for planned outages.
- The one-by-one installation approach has also meant that mobile carrier provided telecommunications services must be used. These services are higher cost (per unit) compared with the RF mesh-based telecommunications used by a majority of the Victorian DNSPs. An RF mesh network typically requires the density provided by a mass rollout to be effective.
- As the consultation paper recognises, reliance on carrier provided 3G/4G and now 5G mobile technologies automatically introduces obsolescence into the meters. This means that smart meters will need to be replaced much more frequently than a normal meter lifespan and, accordingly, the cost recovery over time will need to be higher. Using RF mesh networks dedicated to smart metering means providers can support the technology for longer periods, reducing obsolescence risk.

2a. What is the average life expectancy of basic meters and smart meters?

The 'life expectancy' of a meter should be considered in the context of whether it remains fit for purpose rather than whether it continues to function as designed. Smart meters are necessary for cost-reflective tariff reform. If it is agreed that tariff reform is necessary and desirable, then basic meters should be considered no longer fit for purpose and already past their 'use by' date.

2b. What are the main operating factors that affect the life expectancy of smart meters?

The 'life expectancy' of a smart meter should also be considered in the context of whether it remains fit for purpose. As noted in the discussion paper, a smart meter installed with 3G communication may need to be retired when the 3G network is switched off. The cost of RF mesh-based networks should be compared with the cost of reliance on 3G/4G or 5G technology, taking account of the risk of obsolescence using mobile carrier telecommunications services.

2c. What is the average cost to a retailer of replacing a distributor's basic meter asset before it reaches its end of life?

CEC does not have access to the data needed to answer this question and will leave it to energy retailers to provide the information requested.

2d. What are the factors to be considered before mandating end of life for basic meters?

The overarching consideration should be the new costs and benefits across the entire energy system and how those costs and benefits are likely to be distributed. The factors to be considered should include (but should not be limited to):

- The cost of the replacement meter and how the cost is passed on to customers,
- The benefits of enabling tariff reform across a larger cohort of customers,
- Whether the voltage data from the meter will be made available to DNSPs and the extent to which that data can be used to increase solar PV hosting capacity,
- The increase in solar generation that is enabled by an increase in solar hosting capacity and the benefits for the owner of the solar PV system, and
- The reduction in wholesale electricity prices brought about by the resulting increase in solar generation that is enabled by an increase in solar hosting capacity.
- Potential impact on waste and landfill and strategies for recycling of e-waste that might be generated as a result.

We understand that the minimum technical specification for 'smart' meters is outside the scope of this review. Nevertheless, we must alert DPIE to the risk that meters currently being installed are not capable of doing what is needed from the device at the connection point.

There is an emerging consensus among policy makers that dynamic export limits will apply at the connection point. Policies, standards, and guidelines for interoperability are under active development and the Common Smart Inverter Profile Australia (CSIP-Aus) is being considered for application to DER. A high priority should be to ensure that the device at the connection point can support use of CSIP-Aus. We urge DPIE to consider whether CSIP-Aus capability should be required of the 'smart' meter or whatever other device might take its place at the connection point.

2e. What are the main challenges to replacing basic meters or smart meters that reach their end of life?

A key challenge relates to the allocation of costs. If the cost of meter replacement is borne by the electricity retailer and if there are limited or no financial benefits for the electricity retailer, then it should come as no surprise that rollouts initiated by retailers "have been minimal at most".

Another challenge arises when a smart meter is larger than the analogue meter it is replacing and there is insufficient space on the metering board. The most straightforward way to address this would be to use compact smart meters that are no larger than analogue meters they are replacing. However, this might not occur due to a misalignment in incentives. The company responsible for ordering smart meters does not bear the additional installation cost due to the size of the smart meter they purchase. This misalignment of incentives could be addressed by placing a requirement on the purchaser of the smart meter to ensure that it is the same size or smaller than the meter being replaced, wherever possible. Alternatively, if the purchaser of the smart meter were liable for a proportion of the costs incurred due to the purchase of a bulky meter, that would help to drive the market toward more compact models of smart meters.

2f. What measures should be included to protect vulnerable customers if their meter needs to be replaced? Would exemptions need to be included to account for implementation challenges at some premises?

It would be unreasonable to force low-income households to undertake asbestos remediation if they were charged directly for remediation that is unaffordable. However, it is our understanding that metering installation and remediation costs are smeared over all customers and over an extended period. Insofar as that is a true reflection of current practice, there is not a strong case for remediation costs to act as a barrier to meter installation. A mandated smart meter rollout would provide the most scope for smearing of costs, especially the costs faced by vulnerable customers. Consumers should be given any relevant information in a document written in plain, simple, and clear terms that is easily accessible. Hardship policies should also be in place to accommodate vulnerable consumers.

3a. Are the current installation timeframes, and the measures to monitor compliance with those timeframes, that are required under the national rules appropriate?

The timeframes required under the National Electricity Retail Rules (NERR) seem reasonable, however there appears to be inadequate compliance and enforcement. CEC members have reported delays of up to six weeks.

3b. Are you aware of any regulatory or non-regulatory barriers that may be contributing to delays in the installation of smart meters?

No.

3c. What additional measures would need to be implemented to unlock these customer benefits?

One of the most significant barriers to better utilisation of smart meter data is the power exerted by electricity retailers regarding data access. The current framework for metering makes the energy retailer the gatekeeper for the smart meter and its data. A customer or their service provider can only access this data via their electricity retailer and only in the timeframe and format determined by the retailer. Electricity retailers are conflicted in this role as they have a financial interest in preventing release of data to third parties where that could threaten their business model.

Access to the data from smart meters should not be dependent on electricity retailers' cooperation. The framework for data access should be regulated. The regulatory framework should limit electricity retailers' monopoly powers over data by enabling customers to easily assign data access to service providers without obstruction by electricity retailers. Customers should have access to their data, and it should be easy for them to assign access to their data to third parties and service providers, such as aggregators. To be useful to aggregators to support future innovations such as dynamic export limiting and two-sided markets, this data should be able to be received by the service providers in an automated near real time manner, with a fully online digital sign-up process or locally via a readily accessible port.

It is important to distinguish between data access via the cloud versus real time local access. Real time local access is important for enabling better coordination of devices behind the connection point. A CSV file four times per year is not fit for purpose in 2021.

Customers and their representatives should have access to the data from their own smart meters now. The Consumer Data Right (CDR) process is taking too long, and the existence of the CDR proposal should not be used as an excuse to delay reforms to data access from smart meters.

4a. Should there be a requirement to replace meter boards that are older than a specified age (e.g. 30 years) as a prerequisite to installing a smart meter?

Replacement of a meter board should be triggered by necessity, based on safety, practical considerations or regulatory requirements. Age should not be a trigger for replacement if the meter board remains fit for purpose.

4c. If a meter board survey service can be provided, how much should customers pay for the service? Can the service be offered for free?

Uptake is likely to be very low unless the meter board survey service is free. Even if the survey service can be offered for free customers are unlikely to take up the offer if they think it could lead to a requirement for a costly free meter board upgrade.

Unless the meter board survey service is linked to a free meter board upgrade, the survey could be a pointless exercise.

4d. Should electricity retailers and/or metering providers receive a report on the state of a customer's meter board? If not, why?

Yes. This could be helpful if it differentiates between individually metered sites and group metered sites as it might help rule customers out for solar before applications are placed and work is done. The report should also be provided to the customer.

4g. What is the best way to provide customers, solar panel installers and electricity retailers with information about meter board upgrades?

The information about meter board upgrades could be linked to the requirements of the New Energy Tech Consumer Code (NETCC). The NETCC requires solar panel installers or retailers to provide quotes to customers that include information about the product's expected life, what is involved in disposing of it at the end of its life and associated costs. In addition, information about meter board upgrades could also be included in a NETCC Consumer Information Product, which is consumer information that is approved by the NETCC Administrator to provide independent information to assist a customer or potential customer to make informed choices.

5a. Are there broader benefits (beyond the financial settlements process) to retaining controlled load profiles in New South Wales?

This approach will become increasingly irrelevant in future. If / when the smart meter rollout in NSW is completed sample meters will not be required. In addition, controlled loads traditionally ran at night. With DER becoming more ubiquitous, these loads will more commonly run in the middle of the day. This will decrease the usefulness of measuring controlled load profiles because the load will be supplied by electricity generated on site rather than supplied by the network.

The approach should shift from controlled load profiles to use of dynamic operating envelopes.

5c. What alternative options should be considered?

The first change made to controlled load profiles is that they should be scrapped and replaced with a daylight hour 'solar sponge' tariff. The example of South Australia is worth considering. We understand there are also some DNSPs considering paying customers for exports during the evening peak. These tariffs should be encouraged. Ultimately, the approach should shift from controlled load profiles to use of dynamic operating envelopes.

6a. Should the same obligations be applied to both manual and remote re-energisation and de-energisation services?

Yes.

6b. Do you foresee any unintended consequences of aligning these obligations?

No.

6c. Do you consider there to be any barriers that may prevent a customer being afforded the same protections if they have been remotely re-energised and/or de-energised?

It is more difficult to ascertain remotely that a site is safe to be re-energised, compared with having a person on site. However, safety can be assured with an appropriate plan in place[1].

7a. Is it appropriate to require the sale of hot water to be treated as the sale of energy, to allow hot water embedded network customers to be given similar consumer protections as those in traditional common hot water systems?

Yes. Hot water embedded network customers should have similar consumer protections as those in traditional common hot water systems. There would be no reason to exclude hot water embedded network customers as this cohort of consumers would also benefit from access to independent complaint and dispute resolution, limitations on energy interruptions, hardship provisions, customers requiring life support equipment and billing and metering requirements.

7b. Do you foresee any unintended consequences of requiring hot water embedded network operators to bill customers for hot water in the underlying energy source (in cents per megajoule or kilowatt hour), rather than as a separate hot water product (in cents per litre)?

Yes, potentially. How would operators bill for solar heated water? If they can't bill for the solar energy used to heat water will this be a disincentive to installation of solar water heaters?

7c. Do you consider there to be any barriers that may prevent a hot water embedded network operator from billing customers in the underlying energy source?

Yes, potentially. How would operators bill for solar heated water? If they can't bill for the solar energy used to heat water will this be a disincentive to installation of solar water heaters?

[1] See https://www.fairtrading.nsw.gov.au/__data/assets/pdf_file/0003/910380/Guidelines-for-Development-of-Safety-Management-Plans-for-Remote-De-energisation-and-Re-energisation.pdf

8a. Are the suggested guiding principles appropriate and adequate to guide government strategy for enabling high levels of active DER in New South Wales?

The suggested guiding principles are appropriate. In addition we would urge the NSW Government to consider the following principles:

- NSW households and businesses should have the right to connect DER to the distribution network.
- All NSW households and businesses should be able to participate actively in the DER energy market, including low income households.
- Policy should aim to ensure that DER continues to deliver significant emissions reductions and economic growth in NSW.

8b. What practical measures should the government consider to support DER and the suggested guiding principles?

DPIE could commence with a review of DER-related programs in NSW. The review should consider what has worked, what has not worked and why. It should also compare NSW programs with programs in other jurisdictions. The review should, at a minimum, consider the Empowering Homes program and its results compared with the battery subsidy schemes in South Australia and Victoria. The review should also consider restoring the Smart Energy for Homes and Businesses program to provide more equitable access to all DER technology. DPIE could also consult with the Australian Council of Social Services (ACOSS) and consumer groups to better understand barriers to uptake and to improve equitable access.

DNSPs in NSW should have access to voltage data from smart meters either free of charge or for a low, regulated fee determined on a cost-recovery basis. Lack of access to voltage data is a significant impediment to improving network visibility and hosting capacity on distribution networks in NSW.

Smart meters provide the most efficient means for DNSPs to improve the visibility of their low voltage networks. The data already exists and can be made available to DNSPs with a change to correct the mistakes made during the *Competition in metering* proposal and rule change.

In Victoria DNSPs have access to smart meter data and availability of the data allows the Essential Services Commission to regulate voltage management by DNSPs at a level of sophistication that would be unthinkable in jurisdictions like NSW that are subject to competitive metering. In NSW DPIE struggles to fulfil its regulatory role in relation to voltage management because NSW DNSPs do not have access to the voltage data they need at a price they consider acceptable.

The CEC supports the use of the DER Visibility and Monitoring Best Practice Guide and we urge DPI to consider supporting its uptake either through incentives or by obligation.

8c. How can the government support greater demand side participation and flexibility for customers and demand side participants?

The most important role for government will be to ensure that smart meters are installed in all premises as soon as possible. The current AEMC review of metering services is an opportunity to address the failure of the Power of Choice *Competition in metering* reforms. If the AEMC fails to adequately address the failure of metering policy, then the NSW Government should consider additional measures to drive the smart meter rollout in NSW, including the benefits of a mandated smart meter rollout.

Customers must be given access to their own smart meter data in real time.

There is also an important role for government in acting as a trusted source of information. This could include information on the benefits of properly controlled DER and its potential to reduce the need for infrastructure upgrades to the network, which reduces costs for all consumers.

8d. What material concerns and barriers will need to be mitigated to support DER?

CEC supports the development of distribution-level markets, which would include transitioning from the current role of the DNSP to more clearly defined and delineated roles for the Distribution System Operator (DSO) and Distribution Market Operator (DMO). This would provide a long term approach to addressing issues expected to arise as penetration of solar PV on distribution networks increases to high levels. However, the problems created by the failure of the Power of Choice *Competition in metering* reforms should be addressed before more sophisticated approaches are embarked upon in NSW.

8e. What could be done to ensure vulnerable, low income and other 'locked out' households are not disadvantaged by the energy transition?

By reducing the average wholesale price of electricity, rooftop solar is already saving all energy consumers more than $1 billion annually.

Retrofitting solar PV, batteries and EV chargers can be problematic because:

- In rental properites the 'split incentive' problem discourages investment by tenants and landlords,
- Retrofitting is always more expensive than installation at the time of construction,
- Proving access to batteries and solar PV systems can be problematic unless the building was designed to accommodate them.

To ensure that low income households and renters are not excluded from the benefits of the energy transition, the highest priority for the NSW Government to mandate solar PV and EV chargers in all new residential buildings.

The NSW Government should consider fast-tracking and strengthening the proposed amendments to the National Construction Code (NCC) 2022 in relation to the measures to facilitate retrofits of electric vehicles (EV) chargers. The proposed new requirements include:

- Provision of electrical distribution boards dedicated to EV charging,
- In Class 2 buildings, sizing to accommodate a minimum 7 kW EV charger in 25% of car spaces,
- Sizing to accommodate a 7 kW EV charger in 10% of car parking spaces (for Class 5 or 6 buildings) and 20% of car parking spaces in Class 3, 7b, 8 and 9 buildings,
- Provision of charge controllers to ensure that EVs do not charge during peak consumption periods,
- Distribution board requirements for each storey of a car park based on carpark spaces per storey,
- Empty three-phase circuit breaker slots to accommodate future solar PV and battery systems,
- Sizing to accommodate installation of solar PV panels on at least 20% of the roof area, and
- At least 20% of roof space to be left clear for installation of solar panels (with some exemptions allowed).

8f. What can the government do to improve equity of access to the benefits of clean energy solutions?

Continue to retrofit solar PV onto public housing and social housing. Provide incentives for other controlled DER such as hot water, air conditioning, and pool filters, which would also provide a platform for future controlled EV charging and to consider embedding into new home builds by offering incentives to developers.

Fund programs to enable retrofitting of solar PV on low income, rental households (similar to the Queensland Government's *Solar for Renters* trial) and invest in programs such as solar for remote communities, partnering with Aboriginal and Torres Strait Islander Councils.

Use planning laws and building codes to support the installation of solar PV, batteries, and EV chargers when residential buildings are constructed.

Drive the uptake of the [DER Visibility and Monitoring Best Practice Guide] either through incentives or regulation.

Derogate from the NEM framework for regulation of SAPS so that customers at the fringe of grid can benefit and their access is not impeded by the unnecessary complexity of the NEM-consistent pricing model advocated by the AEMC.

Consider more equitable access for low income households and other vulnerable consumers such as those experiencing family or domestic violence, mental health problems, and those experiencing a natural disaster or crisis event.

8g. How can the government help to unlock the full value of DER and load flexibility on the distribution network, and ensure asset owners are properly protected and compensated?

Key issues that need to be addressed are:

- Address the failure of the Power of Choice *Competition in metering* reforms,
- Ensure that DNSPs have access to the data they need from smart meters,
- Support implementation of dynamic operating envelopes,
- Develop distribution-level markets, and the DSO / DMO framework,
- Ensure aggregated DER has access to all markets,
- Transition from requiring grid services free-of-charge as a condition of grid connection to a market-based approach.

8h. What are the most promising clean energy solutions for delivering material private, network and market benefits?

The key to unlocking the benefits of high solar PV penetration on the distribution network is more controllable, market-responsive energy storage on the distribution network. Community batteries and VPPs are promising business models for providing that energy storage. Use of EVs in vehicle-to-grid (V2G) mode and as part of a VPP represents a significant, untapped, low cost storage opportunity.

DPIE should review the Empowering Homes program and compare the extent to which it has delivered material private, network and market benefits compared with battery subsidy schemes in other jurisdictions, such as SA and Victoria.

9a. How can customers be encouraged to only install solar systems that suit their current consumption needs? What would be the most effective measure to achieve this aim?

The Consultation Paper uses the statistics on the average rooftop PV system size in a misleading way. The data on the average size of a rooftop solar PV system is based on data from the Clean Energy Regulator (CER) in relation to all claims for Small-scale Technology Certificates (STCs). This data includes commercial systems up to 100 kW in size. It is wrong to use this data to assert that the average size of a household rooftop solar system is larger than 8 kW. The data should disaggregate household systems and commercial systems if it is to be used to draw conclusions about the average size of household PV systems.

Unless the customer is consuming most of their energy during the day, the question DPIE should be asking is how we can better incentivise the uptake of storage as well. This should include a review and overhaul of the Empowering Homes program.

Many of the existing three million installed PV systems are small and re insufficiently sized for today's household requirements and will be even more insufficient in future. The electricity consumption profile of many households will change in the short to medium term as electric vehicle (EV) ownership increases. A large PV system is required to power an EV. Assuming average EV energy usage of 15 kWh per 100 km, implies capacity to generate about 10 kWh per vehicle per day for a vehicle that is driven 65 km per day. Average vehicle travel distance will vary by location and will be higher in outer suburbs and regional areas.

DPIE could provide a free, unbiased web-based consumer tool that shows the financial benefit of DER and demand responsive products, tailored to the consumption profile of the individual consumer.

9b. Will changing usage and system demand profiles likely disrupt grid security and reliability in New South Wales, and if so when and how?

The biggest change is likely to come from EVs. The most important role for government will be to enable and encourage EV charging during daylight hours when there is an abundance of solar energy. Key to achieving this will be to ensure EV chargers are available where vehicles are parked during the day. Time-of-use tariffs and adoption of controlled DER would also assist.

In the longer term, NSW will also need to address the challenges of minimum system load. Compared with most other jurisdictions, NSW has a longer lead time to consider the best way to manage the impacts of high rooftop solar penetration. Adoption of controlled DER or use of dynamic operating envelopes would assist with load shifting to address minimum system load.

9c. What can the NSW Government do to mitigate the potential problem of breaching lack of load thresholds?

Support introduction of dynamic operating envelopes.

9d. How can the NSW Government best enable dynamic operating envelopes?

The review should consider the future role of the device at the connection point and the capabilities it will be expected to have. The device at the connection point should be capable of receiving instructions and complying with Dynamic Operating Envelopes, as well as being able to measure and remotely disconnect and reconnect. DPIE should consider the barriers to devices such as home energy management systems or smart inverters being recognised for settlement and becoming the gateway device at the connection point.

To build social license, it is essential that anything other than emergency response measures should be market driven and 'opt in' for customers.

9e. What issues or barriers, including around consumer protections, need to be considered if implementation of dynamic operating envelopes is pursued?

Instead of referring to meters, we should be considering devices that act as the gateway at the connection point to the distribution network. That device at the connection point could be a meter (as it is now) or in future the role of the gateway at the connection point could be filled by other devices, provided they have all the functionality currently required by smart meters.

In future, it will be important for the gateway device at the connection point to be capable of receiving instructions and complying with dynamic operating envelopes. The gateway device could also be responsible for orchestrating DER and controllable load behind the connection point. DPIE should consider how alternatives to revenue meters can enable not only billing, but distribution system operator

(DSO) capabilities such as verification and settlement / payment of non-network services delivered via DER, and payment of wholesale market services delivered by DER.

There are some circumstances under current regulatory arrangements whereby homes and businesses participating in a VPP are required to have two revenue grade meters per site – one at the connection point and one to accurately record output from the solar / solar and battery. This is the case when the electricity from the rooftop solar system is sold to customers in a Power Purchase Agreement (PPA) arrangement. This is an unnecessary cost given that most DER should be as accurate as smart meters.

In the long term, it would make sense for the inverter / gateway device at the connection point to combine its functions with metering.

It is unclear why, in future, all inverters will be required to be capable of communicating using a protocol compliant with IEEE 2030.5, but smart meters will not. It means that the device that acts as the gateway between the grid and the home will be significantly dumber than the devices behind the meter.

10a. How can solar installers and DNSPs ensure all inverters (new and legacy) are set correctly and have the correct capabilities activated?

Solar installers are best placed to ensure that new inverters are correctly set at the time of installation. The role of installers with respect to legacy inverters is limited unless the system is being upgraded or replaced.

Under the legacy inverter standards known as AS/NZS 4777.2:2015 there was an unlimited number of combinations of Volt-Watt and Volt-var settings (also known as power quality settings). Each NSW DNSP had its own power quality settings which were different to every other NSW DNSP. This made the job of the installer more complicated and increased the likelihood of mistakes. The new inverter standard is known as AS/NZS 4777.2:2020 and became mandatory for all new connections in NSW commencing 18 December 2021. Under AS/NZS 4777.2:2020 there are only four regional power quality settings and all NSW DNSPs have opted for the 'Australia A' regional setting. This change should simplify the process for installers and should significantly reduce non-compliance. Before taking any further action, it would be appropriate to monitor the impact of the introduction of AS/NZS 4777.2:2020 on compliance with respect to power quality settings. In future, inverters standards could mandate the capability for remote access, which could vastly simplify the process for monitoring compliance for power quality settings.

10b. Is there value in DNSPs being able to remotely access or communicate with DER assets on their network to check and dynamically manage settings in accordance with changing conditions on the network?

There would be significant value in DNSPs being able to remotely check inverter settings of DER assets on their network. This would be consistent with existing customer agreements. It could be incorporated into the commissioning process.

Dynamic management of settings in accordance with changing conditions would involve an additional level of complexity and would require consideration of consistency of this approach with existing connection agreements and how to address any issues that might arise when settings are dynamically managed. More detailed consideration would be warranted before proceeding with the proposal to dynamically manage settings.

DNSPs should not be remotely switching DER off and on. NSW should preference an approach that has DNSPs sending signals to aggregators to control devices rather than directly intervening in the device itself.

10c. If an additional check of the inverter setting is required, who would be best placed to carry this out?

An additional check could be conducted remotely by the original equipment manufacturer (OEM) if the capability exists or by the DNSP, possibly with assistance from the OEM. If this approach were applied to new installations, it could be mandated as a condition of grid connection approval. An incentive structure would likely be required for this approach to be successfully applied to legacy systems.

10d. Should New South Wales fast track mandating that all new DER installed must be active (i.e. visible and controllable)? What approaches should be considered to ensure these assets are active?

Yes. As noted in the Consultation Paper, work is already being undertaken by AEMO and others to establish communication standards and protocols such as the Australian Common Smart Inverter Profile (CSIP-Aus) for IEEE 2030.5. The Government of South Australia (SA) proposes to mandate use of inverters capable of supporting CSIP-Aus from July 2022. To avoid duplication, rather than initiating its own 'fast track' we would encourage DPIE to participate in the SA Office of the Technical Regulator (OTR) Dynamic Export Limits Committee.

DNSPs should have visibility of conditions on the low voltage network via access to data from smart meters. If DNSPs have sufficient visibility of conditions at the connection point, there is no need for them to have additional visibility of devices behind the connection point.

10e. What frameworks or measures should the government consider putting in place to ensure installed DER systems are compliant with the relevant technical and quality standards?

A logical series of steps that DPIE could consider include:

- Join the OTR Dynamic Export Limits Committee and understand progress to date in this area,
- Assess the capability of NSW DNSPs to support CSIP-Aus compliant servers,
- Assess the capability of manufacturers to communicate with their inverter fleet and to report on settings of inverters,
- Monitor the progress in the OTR Dynamic Export Limits Committee, and
- Consider setting a date from which to mandate the capability to remotely communicate with inverters and verify technical and power quality settings.

11a. Is the AEMO DER register the best way to improve the visibility of DER in New South Wales? What better approaches should be considered?

This register is useful, but it is a static record at point of installation. Real time DER operational status information would be more useful.

The quality of data for NSW in the DER Register is not as good compared with other jurisdictions. Given the importance of improving visibility of DER as part of the energy transition it is worthwhile considering how NSW's performance can be improved, or whether there is a better way to achieve this outcome. Such a review would need to consider the current regulatory overlap around DER, how electrical installations are inspected and certified, the various options for increasing visibility, including the register, as well as the costs and benefits of implementing any different or existing approaches, including NSW Fair Trading and the NSW DNSPs changing the connection application process. For example, other alternatives to the current Register's approach would be collecting this information as part of a certificate of compliance for electrical work (CCEW) that the installer is required to submit as part of the Clean Energy Regulator rebates for solar (noting their intention to ramp up compliance in this space).

NSW's current approach places the onus for completion of detailed DER data on installers following the initial application and often post installation. This contrasts with other states where the solar retailer provides this information as part of the connection approval process on behalf of their customer, which is verified by the installer after installation.

NSW DNSPs should adopt the approach used in all other states to improve the quality of information available on NSW installations on the DER Register. The NSW DNSPs should:

- Better integrate their grid connection approval process with the data required to be collected under the DER Register,
- Require the person making the connection application provide as much as possible of this information for the DER Register as part of the grid connection approval process,
- Following installation, require installers to verify the information supplied by retailers as part of the grid connection approval process, and
- Provide the information collected to the Australian Energy Market Operator (AEMO).

This is the procedure used in all other states and territories in the NEM. Only NSW DNSPs place the onus on the installer to provide detailed information to AEMO after installation.

The absence of a system of inspection and certification of electrical installations in NSW is another reason for the lower rate of compliance in NSW compared with other jurisdictions.

11b. What should the NSW Government do to help improve the visibility of changing operating conditions across the distribution network? Are behind the meter DER assets a viable and cost-effective solution?

The best approach would be to ensure that voltage data from smart meters is available to DNSPs. This might be achieved by the AEMC's review of metering services. If the AEMC review fails to make voltage data from smart meters readily and usefully available to DNSPs then the NSW Government should consider derogating from the metering framework.

Behind the meter DER assets can also provide visibility of changing operating conditions. However, conditions at the DER asset behind the meter might not reflect the conditions at the connection point. Data from the connection point will be more useful to DNSPs. The data is already available, but regulations prevent it from being readily accessible by DNSPs.

We also urge DPIE to consider use of the DER Visibility and Monitoring Best Practice Guide and how best to drive its uptake.

11c. What would an ideal system, data collection and notification process look like to have the best oversight of these assets? Who should be responsible for this system?

The DER Visibility and Monitoring Best Practice Guide would be a good starting point.

11d. Should there be different notification requirements based on the size or capacity of the EV charging or other DER infrastructure not already captured by the DER Register (i.e. 7 kilowatt or 50 kilowatt chargers)?

Knowledge of which locations are experiencing above average EV uptake would allow DNSPs to better plan their network. EV charging equipment could be included in a DER register. However, experience in overseas markets indicates that a significant proportion of customers are likely to charge their EV from an existing power outlet in their garage. A DER register-style approach to identifying the presence of new load at the household level will not be able to capture this situation, because there is no electrical installation being undertaken. Even if an electrical installation is required, it is unclear how the reporting requirement would be enforced if there is no DNSP connection requirement for the charger. The customer cannot be expected to report it, and most home chargers are installed by general electricians who are unlikely to report it.

If the main policy objective is to assist DNSPs with network planning, an alternative approach could involve data provision between Transport for NSW and DNSPs, noting that there could be privacy implications unless data is anonymised.

Most EV charging equipment deployed in homes today is not 'smart' or externally controllable. If the policy objective is to facilitate orchestration of EV charging, then the NSW Government should consider a scheme like the SA Government's Smart EV Charging program.

11e. How can installers of DER be supported to ensure robust reporting of DER data to networks and AEMO? How should compliance be enforced?

Require retailers to provide information as part of grid connection approval rather than requiring reporting by installers after the installation has taken place. Require installers to verify rather than do all data entry. Make the data entry process simpler, less administratively burdensome and less time-consuming. Consider use of the DER Visibility and Monitoring Best Practice Guide.

11f. What should the NSW Government consider in working with AEMO to expand the DER register to incorporate new controllable loads not already captured by the register?

The NSW Government should consider how it would enforce compliance with reporting procedures. The quality of data for NSW in the DER Register is poor compared with other jurisdictions because the reporting is not as well integrated with the connection approval process as it is elsewhere. Compliance would be even more problematic if the reporting requirement is extended to appliances that do not require connection approval.

DPIE should address the problems in the existing reporting processes in NSW before it considers how to extend the system into more challenging areas.

12a. Are there any concerns about community batteries (or other similar DER innovations) from a system or customer perspective that should be considered as part of any future strategy or reform?

Opportunities to add more energy storage on distribution networks are welcome because it will assist with network management, improve customers' access to cheap solar energy and will increase solar hosting capacity of low voltage (LV) networks. Virtual Power Plants (VPPs) is the business model most likely to be in direct competition with the community batteries. This competitive tension is welcome, provided the two business models are treated in a competitively neutral way. VPPs and community batteries should be treated in a 'competitively neutral' way, which could include consideration of Distribution Use of System (DUoS) charges and connection charges.

Further consideration needs to be given to the tariff structures and connection fees for DNSP-owned community batteries, community batteries owned by third parties and VPPs. The tariffs and fees should be based on the principle of 'competitively neutrality'.

From a consumer perspective, some consideration should also be given to ensuring that community battery offers are fit for purpose for customers, with appropriate pricing plans or subscription models, with no upfront costs or lock-in contracts.

12b. What technical and regulatory changes that have not already been addressed should be considered to enable the full value of community batteries and other DER solutions to be unlocked?

It is unclear at this stage whether VPPs in NSW will be subject to DUoS payments:

- once when they import from the grid and again when they export to the grid, or
- only when they import from the grid.

It also remains unclear whether community batteries in NSW:

- will be subject to DUoS payments once when they import from the grid and again when they export to the grid, or
- will be subject to DUoS payments only when they import from the grid, or
- will be exempt from payment of DUoS charges.

Whichever DUoS regime applies to community batteries should also apply to VPPs and vice versa. The DUoS charging regime need not be nationally consistent or even consistent across NSW, but it must be competitively neutral within the same network. DNSPs should not be permitted to give their own community battery a competitive advantage over a VPP with which it is competing.

12d. Are community batteries an economically effective solution to managing the increasing amount of generation from rooftop solar PV on the distribution network? If not, what other solutions should be considered?

The conclusions of studies of the economic merits of community batteries will depend on the assumptions underlying the analysis. Crucial to the analysis are the assumptions regarding payment of distribution use of system (DUoS) charges and whether community batteries would be required to pay DUoS on imports and exports. Assumptions regarding the cost of real estate and planning approvals will also be important in determining the relative benefits of community batteries versus VPPs.

VPPs are an alternative approach to community batteries and are likely to be in competition with them. VPPs could be based on household batteries behind the meter or controllable EV charging infrastructure.

12e. What are the barriers for developing and implementing a community battery project, and then connecting and operating the battery?

Familiarity and experience of the process is probably the main barrier at this early stage. There is a role for government in supporting dissemination of education materials based on the experience of community battery projects to date. Increasing the energy literacy, knowledge and understanding amongst the community (e.g., having open days or information sessions) would help to reduce barriers to developing and implementing a successful project.

12f. What other emerging solutions could enable locked out demographics to participate in the energy transition and benefit from clean energy solutions?

Allume Energy, an Australian solar technology company, has commercialised a technology (called Solshare) which allows one rooftop solar installation to be safely shared by multiple apartments in the same building. Allume is in the early stages of its rollout, with 47 buildings and 758 apartments serviced to date. Allume is expanding in NSW and has interconnection approval from all three NSW DNSPs. This technology also helps residents in multi-unit social housing benefit from rooftop solar. The first installations of Solshare in NSW were on community housing, with residents enjoying electricity bills that were 30% lower due to being connected to shared solar.

Revisions to DNSPs' Service and Installation Rules are needed to accommodate new technologies for behind-the-meter services such as Allume Energy's Solshare.

Western Power has also rolled out a trial using the 'PowerBank' battery that is being used in community battery trials with Synergy, where selected participants can store excess energy and draw on it when needed.

12g. Are there any other ways the NSW Government can support broader rollout of community batteries and other promising DER solutions that can enable locked out demographics to access the benefits of clean energy solutions?

Yes. The NSW Government should build upon other state government programs designed to enable low-income households, renters and apartments to access DER solutions. For example, the SA Government has supported battery installation and VPP participation in public housing in SA. The Queensland Government has recently rolled out a *Solar for Renters* trial in several Local Government Areas.

Victoria's Solar Homes program has been exceptionally successful at extending the benefits of rooftop solar to means-tested recipients. The Solar Homes program has a stream dedicated to community housing that has had extensive take-up by community housing providers, including for multi-unit buildings. The Solar Homes program is also providing grants and finance for residential battery energy storage. The Solar Homes program has not been adequately designed to accommodate strata schemes, and this is an area of program design that could be improved upon in NSW.

13a. How can the NSW Government support the residential deployment of electric vehicles and associated charging infrastructure?

One of the most important steps the NSW Government can take is support for EV charging infrastructure in the places where vehicles are parked during daylight hours. This will encourage load shifting to the middle of the day when there is an abundance of cheap solar energy available. High power DC charging equipment in shopping centres and government buildings and car parks is part of the solution. There is also the potential for the installation of kerbside EV charging in these settings. The NSW Government should consider mandating EV chargers in all new car parks. The NCC 2022 proposes to exempt Class 7a buildings (stand-alone car parks) from any requirements for an EV charger.

Other approaches to driving uptake of EV charging could include:

- Requiring new local council vehicles, buses, taxis and rideshare vehicles to be an EV,
- Exemptions from road charges,
- Incentives for businesses (e.g., tax offsets),
- Provision of information on the benefits associated with EVs.

Established apartment complexes

The key challenges regarding deployment in established apartment buildings are:

1) They are not designed to support the easy retrofit of EV charging equipment,
2) They are heterogenous, so there is not a 'one-size-fits-all' solution.

This creates a barrier to the deployment of EV charging equipment in allocated parking spaces in apartment complexes. For example, before it is possible to install an EV charger in an allocated parking space, it might first be necessary to modify the main switchboard and run new electrical wiring from the main switchboard to the car parking area, at a cost of tens of thousands of dollars. This one-off expense would then enable the future installation of many EV chargers, but it needs to be paid for upfront.

The barrier of the one-off expense could be addressed, at least in part, by an interest free loan facility made available to owners' corporations for deployment of EV charging equipment for established apartment blocks. The loan facility could be used to finance:

- Bringing existing apartment buildings up to the EV readiness standard defined in the NSW apartment design guide. This level of readiness enables individual dwelling owners to install EV charging in their allocated parking spaces at their cost as and when they choose to do so.
- Deploying EV charging equipment in shared parking areas (such as visitor parking spaces) for use by all residents and visitors.
- A shared EV, plus supporting charging infrastructure, for the use of the residents.

<u>New apartment complexes</u>

The cost to retrofit EV chargers is about five to ten times higher than installing them during construction. The highest priority should therefore be for the NSW Government to mandate provision of EV chargers in new buildings.

The NSW Government should consider fast-tracking and strengthening the proposed amendments to the National Construction Code (NCC) 2022 in relation to the measures to facilitate retrofits of electric vehicles (EV) chargers. The proposed new requirements include:

- Provision of electrical distribution boards dedicated to EV charging,
- In Class 2 buildings, sizing to accommodate a minimum 7 kW EV charger in 25% of car spaces,
- Sizing to accommodate a 7 kW EV charger in 10% of car parking spaces (for Class 5 or 6 buildings) and 20% of car parking spaces in Class 3, 7b, 8 and 9 buildings,
- Provision of charge controllers to ensure that EVs do not charge during peak consumption periods,
- Distribution board requirements for each storey of a car park based on carpark spaces per storey,
- Empty three-phase circuit breaker slots to accommodate future solar PV and battery systems,
- Sizing to accommodate installation of solar PV panels on at least 20% of the roof area, and
- At least 20% of roof space to be left clear for installation of solar panels (with some exemptions allowed).

<u>Terrace housing, and homes without off street parking.</u>

Standalone homes with off street parking present very little challenge in terms of deployment of EV charging infrastructure. In many cases, the consumer can use the existing power point on the wall, and installation of a dedicated EV charger is usually a straightforward process. For consumers who park their vehicle on the street, however, a known risk is that the driver will pull an extension lead across the footpath between the car and the home, creating a trip hazard for pedestrians.

The NSW Government also consider the SA Smart EV Charging incentive program as an example of a state scheme trying to incentivise the uptake of smart charging equipment.

13b. What are the roadblocks to the installation of EV charging infrastructure in apartment buildings?

In low rise apartment buildings, it may be simplest to supply the charger from downstream of a resident's energy meter. In this situation, the resident is charged for the energy they consume for their EV without need for additional billing infrastructure or management.

In high rise apartment buildings, it might not be practical to run the wiring from the individual energy meter to the car parking spaces. In these cases, the energy supply for EV charging needs to come from the common property supply. The best way to do this will typically be to install new distribution board(s) in the car park and feed the EV chargers individually from there. Installation of cabling and new distribution board(s) and any associated upgrade costs would be a shared expense. Under this approach, each unit holder pays for their own charger when they want it installed.

On strata boards a vote is usually required for any significant expenditure, and this requires buy-in from owners who might be reluctant to authorise the expenditure because they are unfamiliar with the technology or because they do not see a direct benefit for themselves.

Lack of physical space and the size of the network connection can also present barriers. Retrofitting an EV charger will always be more expensive than installing one during the construction of a building. Therefore, it is important to require EV chargers in all new apartment buildings, along with the physical space for rooftop PV. The proposed new requirements in NCC 2022 relating to EV chargers are for electrical distribution boards and cable trays dedicated to EV charging, and a charging control system. We support these proposals and recommend a ratio of at least 40% of distribution boards to car parking spaces, rather than the 25% proposed by the Australian Building Codes Board (ABCB).

If the chargers are supplied from common property power, some form of cost allocation is needed. The approach to cost allocation will be a decision for the owners' corporation and will require updates to strata bylaws and could also require consideration of the regulations around the sale of electricity. Changes to strata decision making processes implemented by the *Strata Schemes Management Amendment (Sustainability Infrastructure) Act 2020* should be interpreted so that EV charging infrastructure falls under the "sustainability infrastructure resolution" definition. This requires a supporting vote by a majority of a quorum, rather than a majority of all lot owners. This has greatly eased decision making around other DER investments.

13c. Of the three methods listed above, what is the preferred method for connecting EV charging infrastructure in apartment buildings?

Connecting the EV charger to the individual dwelling power supply will generally deliver the cheapest and simplest result. It will deliver a user-pays approach to energy consumption. This would also be desirable for apartments that have their own solar PV system.

Where the energy meters for the dwellings are spread out through the building (typical for high rise), the wiring arrangement for EV charging should be a dedicated EV charger, supplied by common property power. An account linked to the vehicle could enable EV chargers to be shared while charging the user for the energy their vehicle consumes.

13d. Do owners' corporations or strata managers have any concerns about residents contracting licensed electricians to install private charging infrastructure in their parking space and connecting it to their apartment's electricity meter?

Yes. There are two issues of potential concern:

- Wires connecting the EV charger to the energy supply may need to run through common property, and
- The additional load could overload the circuit breaker supplying multiple dwellings.

13e. Should there be different connection requirements based on the size or capacity of the EV charging infrastructure (i.e. 7 kilowatt or 50 kilowatt chargers)?

DNSPs should aim for uniform connection requirements wherever possible, noting that a 7 kW charger can be operated on a single phase connection whereas a 50 kW charger would require a three phase connection.

13f. Who would be best placed to own and operate EV charging infrastructure in apartment buildings?

Apartment owners may choose to own and maintain their own charging infrastructure, much like homeowners will. Strata committees will increasingly see the value of installing and owning EV chargers to make their buildings more attractive places to buy or rent. Owners' corporations might contract a third-party service provider to manage EV charging infrastructure in much the same way that they would contract out the management of an elevator, for example. It is also possible that a third party will own the charging equipment and that it will be made available to residents on a contractual basis.

An aggregator, retailer or VPP operator would likely be responsible for any bidirectional trading of energy.

13g. How should the costs of the EV charging infrastructure in the apartment building be accounted for?

There are a range of possible approaches. We anticipate that many different business models for ongoing management and billing will emerge. It would be prudent to leave room for the market to evolve.

It is reasonable to expect that energy costs will be borne by the person charging their EV. This implies that the costs of installation and maintenance should be accounted for separately to the cost of energy.

Installation and maintenance will likely be treated as part of the normal cost of owning an apartment building. Individual chargers will likely be paid for by its owner.

Shared infrastructure will incorporate any necessary upgrades to the building main switchboard, the addition of new distribution boards and supporting wiring in the car parking area. It could also include shared EV charging equipment in visitor parking spaces. Costs for shared infrastructure should be shared across owners, rather than being paid for by the first adopters. However, it is a significant expense and would require majority support of the owners' corporation. Access to a zero-interest loan facility would assist investment in shared infrastructure.

13h. Do electricity retailers or any other entities offer any specialised plans or discounts to incentivise EV charging infrastructure in apartment buildings?

Many organisations are offering EV charging solutions for apartments and more providers will emerge as the market develops. A risk against which the NSW Government might wish to guard through policy intervention is that of consumer lock-in. Choices made by a developer or an owners' corporation could limit the ability of apartment residents to easily change suppliers.

13i. Would it be fair to charge EV charging infrastructure users fees for installing, maintaining, and operating EV charging infrastructure in strata schemes (in addition to energy consumption charges)? Who should pay for these and why?

As EV uptake increases, EV charging infrastructure will be viewed as essential infrastructure for apartment buildings. Ultimately, decisions about when to install EV charging infrastructure and the type of infrastructure installed will be made by the owner's corporation and will add to the value of the apartments. It therefore seems reasonable for the infrastructure costs to be borne by the owners' corporation or the owners of the apartments.

13j. Should energy consumption from EV charging infrastructure on common property be paid for by users or borne by the owners' corporation?

A user-pays system for charging for energy consumption is likely to be perceived as the most equitable approach.

13k. Who should be responsible for managing and controlling the use of EV charging infrastructure on common property?

Management and control should be the responsibility of whoever owns the common property. The owners' corporation will need to set bylaws governing the use of EV charging infrastructure supplied by assets held as common property. The owners' corporation may also elect to outsource its management responsibilities to a third-party service provider.

14a. What are the stakeholder views on the AEMC's proposed service delivery model?

Remote, fringe-of-grid customers are likely to be the main beneficiaries of SAPS reforms. Providing remote, fringe-of-grid customers using SAPS is where the largest cost savings will be made. It is highly likely that individual power systems, rather than microgrids, will be the most appropriate form of alternative supply for remote, fringe-of-grid customers.

The AEMC's proposed service delivery model is unnecessarily complicated and cumbersome for individual power systems. By prioritising retention of the role of the retailer and the retail contract, the AEMC has over-complicated the model to the point where some distribution network service providers (DNSPs) have expressed concern that the complexity of the proposed service delivery model will lead to very low uptake of SAPS. In addition, by maintaining the link to wholesale electricity prices, the national framework inadvertently reduces the incentive for the creation of innovative SAPS products and services for the relatively few SAPS customers (compared to the size of the customer base) which are aligned to the optimum use of the system. Reduced innovation in products and services for SAPS customers will reduce customer choice and limit the cost savings available for consumers.

In 2017 the NSW DPIE identified the need to review consumer protection frameworks to ensure that regulations meet the needs of customers of new energy products and services and to determine whether and what type of regulatory reform may be needed, particularly with respect to protection of customers served by DNSP-led SAPS.

CEC's submission to the DPIE discussion paper, *Protecting consumers in a changing energy world*, made the case for the following energy reforms to protect customers on DNSP-led SAPS:

- DNSPs should be permitted to own and operate SAPS and to supply electricity to existing customers using SAPS wherever that would be cheaper, safer and more reliable than traditional poles and wires.
- To ensure that consumers supplied by SAPS continue to receive safe and reliable electricity supply there should be:
    - Enforceable standards for reliability and safety,
    - Regulatory oversight of prices by the Independent Pricing and Regulatory Tribunal (IPART), and
    - Universal access to dispute resolution processes.

We restated this position in our submissions to the 2018 AEMC Issues Paper on SAPS. In our submission to the AEMC's 2019 Draft Report on SAPS, CEC opposed the proposed 'NEM consistency model' and stated our preference for the 'integrated service delivery model', especially for management of independent power systems and small microgrids. For more than four years, the AEMC persisted with developing its 'NEM consistency model' for DNSP-led SAPS.

Sadly, that work has unnecessarily complicated matters, has delayed the uptake of SAPS and has set back the prospects for the use of DNSP-led SAPS. Under the AEMC national framework, there is a greater likelihood significantly less SAPS likely to be installed, which will not be in the long-term interests of customers. In the absence of NSW specific SAPS reform, the national framework is likely to fail to deliver optimal customer experience and pricing outcomes for NSW customers, particularly those who live in regional and remote areas. In addition, DNSPs will lose the ability to embed resilience in the network and meet environmental objectives.

14b. Should DNSP-led SAPS customers always be required to contract with an energy retailer?

No. It is illogical to attempt to disaggregate generation, distribution and retailing functions for the purposes of regulation of individual power systems provided by DNSPs. This unnecessarily complicates the business model for very little apparent benefit. The requirement for DNSP-led SAPS customers to contract with retailers will create customer service quality and other issues that arise through the multiple contact points involved in responding to a faults / general SAPS enquiry. When a fault occurs, a customer would have to contact their retailer which must then determine which DNSP must be contacted and initiate a response accordingly. Information and updates must then be relayed back through the retailer so that the customer can be informed of restoration times and progress. These multiple contact points add complexity, the opportunity for customer confusion and the likelihood of additional delays and costs. From a service offering perspective, customer outcomes would be better met through a 'one stop shop' where there is direct accountability (and regulatory remedy) with the DNSP SAPS service provider.

14c. Or is direct retail contracting with the relevant DNSP appropriate where the customer provides explicit informed consent? If so, under what circumstances?

Direct retail contracting with the relevant DNSP is appropriate when an individual power system is used by the DNSP for regulated power supply. Regulatory oversight of prices will be necessary to ensure that consumers supplied by a DNSP using an individual power system pay a fair price for their electricity where there is a lack of competitive tension. Prices could be regulated by IPART or by reference to an accepted benchmark such as the standing offer price.

Regulatory oversight would ensure delivery of the policy principle that customers would be "no worse off" because of being transitioned to a SAPS and would continue to maintain their existing customer protections with respect to the prices they pay. This option is likely to deliver the greatest savings for customers and offer the most flexibility and customer choice, without impacting their customer protections.

Removing a retailer from the SAPS customer relationship is unlikely to have a significant impact on the retail market, given the anticipated low volumes of SAPS customers. Removing the role of the retailer would not mean that customers would lose their National Energy Customer Framework (NECF) protections either. These can be provided by the DNSP with appropriate regulatory oversight.

It is also worth noting that in any transition to a SAPS solution DNSPs would already be undertaking the bulk to active customer consent and engagement activities to ensure SAPS benefits are realised. This is because SAPS are generally located on the customer's property and DNSPs need to work closely with customers to understand their load profiles and technical requirements. In return, customers, particularly those in remote areas experience improved reliability outcomes and aesthetic benefits through the removal of existing poles and wires on properties. Direct contracting is a natural extension of this pre-cursor work and engagement.

14d. Should the same service delivery requirements be applied for both individual power systems (SAPS supplying single customers) and microgrids?

It would make more sense to consider generation, distribution and retailing as separate functions in microgrids, where there are two or more customers. Where there are two or more customers, the retailer would provide a relevant service – separate billing. In the case of an individual power system, insisting on the insertion of a retailer into the business model provides no material benefit to the customer and makes the service delivery model unnecessarily cumbersome.

14e. Which service delivery model do stakeholders prefer?

CEC strongly prefers the 'integrated service delivery model' to the 'NEM consistency model'. This is especially so for the case of DNSP-led SAPS based on individual power systems.

The most appropriate service delivery model for DNSPs to use individual power systems for regulated supply would involve:

- Allowing the DNSP to own and operate the individual power system as generator, distributor and retailer,
- Regulating for pricing, reliability, and safety, and
- Providing access to independent dispute resolution.

The AEMC's preferred "NEM consistent' service delivery model could have advantages for large, town-sized microgrids. However, it will be an impediment to the efficient use of DNSP-led individual power systems for regulated supply of electricity.

14f. Are there other options the NSW Government should be considering?

The 2017 DPIE discussion paper, *Protecting consumers in a changing energy world*, also considered consumer protection in a situation where a community decides to be off-grid using a microgrid. Regulatory frameworks for microgrids that are owned and operated by entities other than DNSPs should be considered in the longer term. However, the priority for regulatory reform should be with respect to DNSP-led use of individual power systems for regulated electricity supply.

We anticipate that the Energy and Water Ombudsman NSW would be the most appropriate body for independent dispute resolution.

15a. What are stakeholder views on the AEMC's proposed pricing model?

The AEMC's proposed pricing model overcomplicates pricing for SAPS for no apparent benefit. It is unclear why it would be desirable for SAPS customers to face electricity charges that reflect the cost of supply on the National Electricity Market (NEM). Under the national SAPS framework, the linkage to the wholesale market does not reflect the cost to supply a SAPS customer and therefore there is no clear pricing signal to the customer to optimise the system. For instance, in summer months, NEM wholesale prices tend to peak during the day – this is the inverse of the cost structure of generation in a SAPS as solar output is highest during the day. Prices in a SAPS environment should therefore be low during the day to leverage the output of the solar panels and minimise draw on the battery. A wholesale linked SAPS price would signal the opposite with high prices during the day. As a result, there is a risk that SAPS will be over-engineered to accommodate the historical energy usage patterns of the customer. This can lead to higher costs that could otherwise be avoided.

Pricing to customers supplied by SAPS should reflect the cost to supply them, rather than the costs on the NEM. This will provide customers with efficiently size SAPS systems and will lower the costs borne by all network customers.

15b. To what extent is non-cost reflective pricing a barrier to the roll-out of SAPS systems?

There is no need or benefit in structuring pricing for SAPS customers so that it reflects costs to supply through the NEM. The absence of pricing reflective of NEM costs presents no barrier whatsoever to the roll-out of SAPS systems. Costs to supply on the NEM should be irrelevant to pricing for SAPS customers. Insisting that SAPS customers must face pricing reflective of costs on the NEM is misguided and ideological. Indeed, the required linkage to AEMO settlement systems to give effect to a SAPS wholesale settlement price, requires system investment and updates from AEMO system teams, which will potentially further delay the roll out of SAPS in the NEM. Given the small number of SAPS systems expected, a more pragmatic approach is needed.

15c. Given the limited number of expected SAPS customers in New South Wales, would it be more practical to maintain NEM consistent pricing?

No. It would be far more practical and sensible for pricing to SAPS customers to be reflective of the cost to supply the SAPS customers using the SAPS system, and subject to pricing oversight. Options could include a subscription model, a SAPS TOU tariff, reward-based pricing, and even potentially individualised product offering based on customer preferences. Under all options the policy principle that customers would be "no worse off" as a result of being transitioned to a SAPS could be maintained through appropriate regulatory oversight.

15d. To what extent is the pricing model likely to affect the efficient sizing of the SAPS system and the customer's experience?

The pricing model will affect the sizing of the SAPS system and how customers use it. The AEMC's proposed pricing model would prevent customers from facing pricing that would encourage them to optimise the use of the system supplying them. A much simpler approach to cost reflectivity for SAPS systems could involve co-contribution by users to the cost of diesel generation as back up.

16a. Do stakeholders feel the AEMC's proposed service classification arrangements are suitable?

No. The AEMC's proposed service classification arrangements are overly complicated.

16b. Do stakeholders feel the AER's final ring-fencing guidelines adequately support DNSPs to provide generation services in the absence of a market for third-party provision of SAPS generation services?

The AER's final ring-fencing guidelines were an improvement in that they provide an exemption that allows DNSPs to own and operate generation services for DNSP-led SAPS. However, the exemption cap for generation assets is arbitrary and concerns regarding the impact on competition would be better addressed through a framework of regular reporting and review.

16c. Should consideration be given to an increased exemption cap above that provided by the AER's national exemption cap?

CEC's submission to the AER review of its ring-fencing guidelines argued against setting prescriptive exemption caps. Use of SAPS by DNSPs is likely to start with relatively small numbers of installations, with numbers growing over time as the technology is better understood and as the economics improve. The difficulty with setting prescriptive exemptions now is that they are not based on experience and there is very little real-world data on which to base decisions. Rather than beginning with a large set of narrowly defined exemptions, we recommend a generic exemption approach supported by a framework of reporting and review. This would enable regulators to review the impact of DNSP decisions on competition and whether changes are needed. This would also allow time for the Australian Energy Market Commission (AEMC) to continue the development of the policy framework for third-party SAPS (priority 2). The delays in progressing the reforms for third-party SAPS are likely to be a more material barrier to competition than the thresholds for exemptions.

Rather than focusing on where to set exemption thresholds, the focus should be on the processes that DNSPs use for procurement of SAPS-related goods and services. In a future review process, it would be helpful to have the following information:

- How many SAPS has each DNSP installed, what was the total value and average cost per system?
- What selection criteria were used to identify suitable locations for DNSP-led SAPS?
- What were the procurement processes used? Was any of the work awarded to the DNSP's affiliated entity? If so, what proportion?
- What was the rationale for the selection of procurement process?
- How competitive was the process and what plans are there to open the process to more competition?

16d. Are stakeholders of the view that some form of change is needed to enable network ownership of SAPS generation assets?

Yes. DNSPs should be allowed to own the generation component of individual power systems used for regulated supply of electricity. Ownership of generation should not be limited by an exemption cap and instead should be subject to a process of reporting and review.

16e. Which service classification option do stakeholders prefer?

As a first preference, we support moves by NSW to derogate from the national framework to allow DNSPs to own and operate generation assets and include these assets in their Regulated Asset Base (RAB). This would guarantee that the benefits SAPS systems could be provided to select NSW customers within the current 2019-2024 regulatory control period. These derogations could be easily made at the same time as the NSW Government opts into the SAPS national framework which we understand is scheduled to occur in mid-2022.

As a back up option, we would also support the proposal for NSW to work with the AER to reclassify SAPS generation through the Framework and Approach process, including classification of specific SAPS services (e.g. fault repair and maintenance to generation assets) as part of a distribution service. Nonetheless, noting that that service classification is an AER led process, this is no guarantee this would occur. This reform pathway would also mean SAPS solutions couldn't be offered to NSW customers until the 2024-2029 period at the earliest.

17a. What kind of information, or which topics, do customers find most challenging or confusing to find information about in relation to smart meters, DER and/or other energy technologies?

Consumers find it confusing and complex to understand what DER they should get (other than solar) and why it should be smart.

It is extremely difficult for a consumer to decide whether they should get controlled hot water, a heat pump, a battery or take some other action. Furthermore, there is no trusted information on why they should opt for smart DER rather than passive DER.

Consumers generally would like to understand the risks associated with DER and energy technologies, and any anticipated savings and other benefits of their purchase. They want access to clear and independent information and how to make the right purchasing decision, and to understand government initiatives and any rebates available.

Different levels of energy literacy, influenced by different levels of consumer vulnerability, will affect what customers find challenging or confusing. It can be a challenge to access clear, plain, easily understood information in an industry that is highly technical and prone to jargon.

Assessing the suitability of energy technologies for the home is an area that consumers find challenging.

17b. Are customers likely to access the information on a website using a dedicated desktop browser or a mobile device?

Both. It depends on the demographic. A significant proportion still use desktop (or laptop) computers. Installers are more likely to use a mobile device, particularly when they are on site.

17c. Would customers prefer to focus their research journey by learning about the various technologies available to them, or by learning about their specific dwelling type?

They want to know which technology type will be best for them. They are not interested in general information about technology. They want information to assist them with making their purchase decision.

The most suitable technology for a customer will depend on the customer's dwelling type. Customers living in a free-standing house that they own could be adequately serviced with generic information about various technologies. Information tailored to the customer's dwelling type would be valuable for customers with specific circumstances, such as those who rent, those living in an apartment, and those who are in a fringe-of-grid location, for example.

18a. Would customers prefer to review emissions performance based on the electricity retailer (i.e. the business) or based on the electricity plans offered?

It would be preferable for customers to have access to data on the emissions performance of the business and the electricity plan offered. However, only about 10% of customers prioritise emissions when they select an energy plan. Most care about costs. This is why solar is so popular.

18b. Where would customers prefer to see information about retailer emissions (e.g. on a bill, on the retailer website, on a retail plan comparison site, or a combination)?

Both. However, it's more important that customers have access to advice on what action they can take for themselves, such as installing smart DER.

The key issue is first to require retailers to disclose data on the emissions performance of their business and the electricity plans they offer. Data on the emissions performance of the businesses should be published on a DPIE web page. Once that information is published, it is likely to be used by retail plan comparison sites and for the purposes of marketing. The NSW Government should focus on mandating publication of the data rather than getting distracted by discussions about the best way to present it.

18d. What information do retailers already collect about the generation sources when purchasing electricity; for example, to meet internal targets or the RET?

CEC does not have access to the data needed to answer this question and will leave it to energy retailers to provide the information requested.

18e. What offset programs do electricity retailers currently participate in? Are the programs in Australia or international?

CEC does not have access to the data needed to answer this question and will leave it to energy retailers to provide the information requested.

18f. What actions, if any, do electricity retailers take to promote GreenPower? Do electricity retailers offer GreenPower at a competitive market rate, or absorb any of the costs? How many of your customers opt-in to GreenPower?

CEC does not have access to the data needed to answer this question and will leave it to energy retailers to provide the information requested.

18g. Do retailers foresee any complexities or challenges reporting on the draft criteria?

CEC does not have access to the data needed to answer this question and will leave it to energy retailers to provide the information requested.

18h. How often should the information about retailers' emissions performance be reported: monthly, quarterly annually (by calendar year or financial year)?

It should be reported at least annually.

19a. Are customers and energy retailers aware of new, energy efficient or emerging life support equipment that are not eligible for the NSW LSR?

Yes. Battery back-up for life support equipment should also be eligible for the NSW Life Support Rebate (LSR).

Priority should be given to provision of smart meters for life support customers. This would assist DNSPs with prioritising life support customers in the event of an outage. It would also eliminate the need for meter reading visits to medically vulnerable customers during COVID-19 outbreaks or lockdowns. We support the proposal put forward by Essential Energy that DNSPs could be given an enhanced role in supporting the rollout of smart meters to life support customers.

19b. How often do energy retailers reject an application for the NSW LSR based on equipment type (if this data is available)?

CEC does not have access to the data needed to answer this question and will leave it to energy retailers to provide the information requested.

19c. Can electricity retailers advise how many of their customers have notified it of life support equipment requirements but do not receive the LSR in New South Wales.

CEC does not have access to the data needed to answer this question and will leave it to energy retailers to provide the information requested.

19d. How often should the NSW Government review its list of approved life support equipment?

The list should be reviewed regularly, possibly every two or three years, so that it can take account of new product development and include the most suitable, cost effective and energy efficient equipment available on the market.

19e. How can medical declarations that support a customer's need for life support equipment be automated to reduce the burden on impacted customers?

CEC does not have access to the data needed to answer this question and will leave it to others to provide the information requested.

20a. Would customers and DNSPs benefit from greater digitalisation of communication between them?

Yes. Use of SMS and text messages to notify of outages is very beneficial.

Customers want simple digital communications and the ability to make all their data available to innovative third parties to provide the information and services they want.

20b. Are there current barriers to DNSPs communicating to customers electronically?

DNSPs are not suited to communicating with consumers. They are not a customer facing organisation. This should be done by the energy retailer, or a consumer authorised third party who specialises in customer services.

20c. Would the development of systems that support customers opting-in to receive electronic communications and notices from their DNSP be of value?

If consumers could choose whether they receive electronic communication that could improve service delivery and help to build trust in the DNSP. However, a better way may be for consumers to authorise third parties to interpret this information for them.

21a. If embedded network operators were required to report on their 'child' connection points, should this reporting be done to the AER or their local distribution network?

The NSW Government has the power to introduce a regulatory requirement for DNSPs to request information from their customers about whether they are embedded network operators and report this to government. The NSW Government cannot unilaterally change the reporting requirements to the Australian Energy Regulator (AER) under the National Electricity Rules (NER). If the NSW Government sees this reform as a priority, it should regulate directly, rather than hoping the AER might do it.

21b. Other than status as an embedded network, and the number of 'child' connection points, what other data reporting requirements would be of value?

In January 2022 an expert panel appointed by the Victorian Government recommended banning embedded electricity networks in new apartment buildings and reforming existing networks to ensure all Victorians have access to the same competitive retail offers and consumer protections. The panel recommended reforms for new and existing embedded network customers in apartment buildings, supporting the Government's proposal to ban new networks from 1 January 2023 with exemptions if operators can show that 50% or more of a site's electricity consumption is met by on-site low-cost renewable energy.

With a view to enabling similar reforms in NSW in future, DPIE could consider requiring embedded electricity networks to report whether 50% or more of an embedded electricity network's consumption is met by on-site low-cost renewable energy.

22c. Are there any new or emerging customer needs in the energy space that government should explore?

Yes. The NSW Government should consider banning high pressure sales tactics, such as door-to-door sales or cold-calling. These harmful energy sales tactics are banned by legislation in Victoria, and the ban applies to solar sales as well as electricity and gas retail offers. Door-to-door sales are often the source of bad consumer experiences when high pressure sales tactics lead to poor decisions by consumers.

It seems likely that in future there will be a requirement on DER to either be smart or export limited and there could be a role for DPIE in assisting with this change.

The NSW Government should also consider providing an independent, trusted tool for consumers to understand what smart DER can provide for them in the context of their personal circumstances.

Increasingly, consumers are also concerned about recycling initiatives and the impact of any e-waste that might end up in landfill. The NSW Government should also consider the end of life implications of its energy initiatives.