Submission to the AEMC Approach Paper: *Distribution Market Model*

(AEMC Reference: SEA0004)

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January 2017

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About the authors and the CONSORT project

*The authors of this submission are involved in the **CONSORT Project**, also known as the **Bruny Island Battery Trial**. The CONSORT project team is made up of industrial partners Reposit Power and TasNetworks, and researchers from the Australian National University, The University of Sydney and the University of Tasmania.*

CONSORT is an ARENA funded research project and field trial, which is addressing how batteries can be used by householders to manage their energy while simultaneously being used to help manage the network. During the trial, up to 40 battery systems are being installed in homes on Bruny Island in Tasmania's south-east. Working in conjunction with rooftop solar generation, these batteries will be coordinated to alleviate congestion on Bruny's undersea power supply cable and to reduce the reliance on costly and polluting diesel generation during peak season. More on the CONSORT project can be found at: http://brunybatterytrial.org/

*Although the authors all share an affiliation with the CONSORT Project, this submission reflects their own opinions and perspectives. Specifically, **this submission is not a reflection of a CONSORT Project-wide consensus view on the matters raised in the approach paper.***

1. Introduction

The University of Sydney (USyd) and Australian National University (ANU) welcome the opportunity to contribute to the Australian Energy Market Commission's (AEMC) project on Distribution Market Mechanisms, and thank the Commission for initiating this program of work.

We feel this project provides a timely and important opportunity for stakeholders to contribute to the ongoing work of facilitating the uptake of distributed energy resources (DER), particularly those embedded in distribution networks and "behind the meter." We believe that continued efforts to harness the full potential of DER will contribute towards the long-term interests of consumers in the NEM.

In the past, distribution networks were treated as passive components in the power system. The recent development and uptake of economical options for local generation, such as residential photovoltaics (PV), and increasing use of high-power devices, such as air conditioners, has lead to significant changes in residential feeder load profiles. Subsequently, this lead to increased investment in distribution network assets, and a commensurate increase in the costs of providing, and prices charged for access to, distribution networks.

In particular, current NEM arrangements (and those of almost all electricity industries around the world) do not provide economically efficient means for consumers to actively participate in distribution network management to reduce costs, be that their own private energy costs or electricity system-wide costs. More generally, the role that a wide range of distributed energy options - such as local generation, storage and flexible loads - might play in delivering network services, while understood in theory, is only just being realised in practice. Specifically, the advent of controllable technologies, such as residential battery storage and flexible loads, presents itself as an outstanding technical solution to mitigating the above mentioned drivers of distribution network cost increases, as well as contributing the flexibility required to complement variable sources of renewable energy supply. However, given the continued evolution of technological developments in this space, it comes as little surprise that designs for the institutions and market arrangements that enable and facilitate the delivery of these services, and their integration into existing energy market and frameworks, are not settled.

Within this context, in order to advance the National Electricity Objective (NEO), the AEMC have stated that they will use this project to explore:

- the technical opportunities and challenges presented by distributed energy resources;
- what, if any, new roles, price signals and market platforms are required to optimise the development, deployment and use of distributed energy resources;
- how the role of distribution network service providers (DNSPs) may need to adapt to facilitate a transition to a more decentralised market for electricity services;
- whether the existing electricity regulatory framework impedes or encourages innovation and adaptation by DNSPs to support the efficient uptake and use of distributed energy resources; and
- whether changes to the existing distribution regulatory arrangements, or the design of a new market, are necessary to address any impediments to business model evolution.

We are largely satisfied that the AEMC have developed a project scope that captures identifies many of the key issues regarding the development of decentralised markets for electricity and network services at the distribution level, covering relevant aspects of future distribution network operation and development.

Nonetheless, the remainder of this submission provides detailed feedback on the approach paper, including extensions of the project's scope and definitions.

In particular, we encourage the AEMC to continue to focus on longer term considerations of dynamic efficiency in energy service provision, in addition to obvious roles of that market forces play in delivering allocative and productive efficiency. This should include consideration of ways to facilitate investment in and development of new technology by networks and other parties, the evolution of new business models, and the consistency of network pricing and cost recovery methods over time. These considerations stand in contradistinction to a focus on the regulatory and market arrangements that deliver short-run allocative and productive efficiency only.

The structure of this submission is as follows: First, a technical background is provided, outlining key recent development and transitions in the electricity sector. Section 3 then considers alternative ways mathematical models can be constructed for distribution markets. This section focuses on the methods employed in the CONSORT project, as a way of explaining what is possible. Section 4 then provides detailed responses to the consultation questions posed in the approach paper.

2. Background

Power systems are undergoing a major transformation driven by the emergence of cost-effective behind-the-meter DER, including onsite generation, energy storage, and flexible loads, and the technological advancement in the sensor, computer, communication and energy management technologies are changing the way electricity users source and consume electric power. The concurrent uptake of variable renewable energy sources (RES) at the supply side is further complicating this transition.

The flexibility of the demand side has been recognised as a valuable system resource for a long time. Historically, various demand response (DR) and demand side management (DSM) programs have been used as a reliability and capacity resource to manage emergency and peak load events, respectively. Under the old generation-following-load operation paradigm, DR was an effective way of managing predictable discrete events. The increasing variability and dispersal of supply, however, will require a more generation-like resource to provide balancing services, and more active control of low voltage networks.

However, the structure of existing DR and DSM programs is not fit for the purpose of distribution network management. Existing methods predominantly rely on large industrial customers with electricity-intensive processes that can be used as curtailable loads. These loads are relatively easy to aggregate, and they are often connected at the medium voltage level and above.

In contrast, the bulk of customers on distribution networks consist of residential and small commercial and industrial buildings, with fast, flexible and continuously responsive DER connected "behind-the-meter." They also present the largest untapped pool of DR resources, which makes them a key enabler of future grids with high penetrations of renewable generation.

These devices are highly granular and therefore well suited for distribution network management. There are, however, significant technological challenges associated with tapping the flexibility of DER, which renders conventional aggregation techniques infeasible. In more detail: (i) they are highly diffuse; (ii) the nature of their energy usage is inherently task-oriented, (iii) they have highly variable stochastic energy usage patterns; and (iv) their number is potentially very large. Furthermore, these technical challenges are overlaid by the economic challenges of: (v) appropriately compensating electricity customers for using their private devices to deliver power system services; and (vi) having customers commit in advance to participating in such DR schemes, without manipulating the system.

Accordingly, a viable solution for harnessing the flexibility of the "behind-the-meter" DER will need to solve a number of fundamental challenges. First, it should appropriately balance users' financial benefit with any effects on their comfort. Second, it will need to consider network constraints explicitly, given that the targeted resources are mostly connected to lower voltage levels. Third, the aggregation scheme should be computationally scalable and communicationally feasible. And last, it should be robust to customer manipulation and collusion.

It is imperative that the AEMC's Distribution Market Mechanism project consider these aspects as a unified whole, because treating them as separate objectives or constraints is unlikely to result in an outcome that effectively contributes to the long-term interests of consumers in the NEM. This requirement mimics that of the joint consideration of transmission network constraints, generator characteristics and costs, and stability requirements of dispatch decision making in the NEM wholesale energy markets.

However, this analogy belies the for electricity regulators and regulated entities, such as networks, to also consider the effects of rapid technological change on the investment cycle dynamics of customers connected to the wider grid. This includes rapid reductions in the costs of installing particular technologies. Specifically, market mechanisms and regulatory changes that support investment in sufficient service capacity, including technological developments that facilitate novel means of procuring services, need to be examined alongside operational design of any distribution market model. This may also make the Commission's preference to translate approaches from the operations of transmission networks to the distribution level a difficult task to apply in practice, outside the provision of *system* services, such as overcoming system peak and ramping constraints or frequency control ancillary services. A detailed treatment of these issues is provided in the next two sections.

3. Approaches to Distribution Network Market Design

3.1. Aims

The Distribution Market Model (DMM) project aims to set out a range of potential market design options that the AEMC can implement to address emerging regulatory and technical issues. The approach paper listed four key sets of considerations:

- the roles and functions that must be undertaken in any future distribution market;
- the advantages and disadvantages of each option, and their relative costs and benefits;
- what would need to be done in a regulatory sense to implement each option; and
- the advantages and disadvantages of each option in relation to the Commission's proposed market design principles and the NEO.

We take the perspective that detailed mathematical models of the distribution network (DN) and customer DERs can help inform both the design and operation of a DM. In the following, we briefly discuss modelling considerations and how such models can be used to enhance the outcomes for a DNSP.

3.2. DN models: constraints, objectives and customer responses

One approach to modelling a system is to break it up into distinct agents with their own individual objectives and constraints. In the DN, the most important agents are the DNSP and customers, with retailers also potentially playing a part if the goal of the DMM extends beyond local network management issues to wider wholesale market considerations.

When modelling the behaviour of an agent it is useful to think in terms of their actions, constraints and their objective. The DM specifies how agents interact with one another and the payments that are exchanged between them, it therefore influences their model, for example, by adding a new revenue stream for providing grid support (which they need to consider in their objective).

3.2.1. DNSPs

The primary objective of a DNSP is to provide their customers with safe and reliable access to electricity, and to do this within a limited operating budget. With customer adoption of DERs this objective is shifting towards not just providing customers with access to electricity consumption but also with the opportunity to provide power back into the network. Putting faults to one side, the key physical constraints that limit their ability to achieve these outcomes in a high DER future are the current carrying capacity of equipment (e.g., conductors and transformers) and their rated voltage limits. In addition, regulated limits on voltage at the point of customer supply must also be considered.

Many of the actions that DNSPs can take to meet these constraints are longer term making them not directly relevant to an operational DM, e.g., the decision as to whether or not allow a new solar PV customer to connect or whether to augment the network. Other everyday actions are automated such as the voltage control of automatic tap-changing transformers. Some actions such as the operation DNSP-owned generation could make use of a DM to improve decisions around generator operation.

A good starting point for a DNSP model that is relevant to day-to-day operations of a DM is a model of the network itself that simulates voltages and currents on network and includes their limits as well as an objective that takes into consideration any operating costs including DNSP-owned generation. Armed with such a model a DNSP can make informed decisions about how they should implement network, technical or operational solutions; or, alternatively, as is investigated in the CONSORT project with the Network-Aware Coordination algorithms, the network model can be built into the market itself in order to ensure that the market-based solutions produced meet the operating constraints of the network.

In fact the NEMDE takes the second approach described above, where an internal model of power flows (e.g., on the the state interconnectors) is used to guide the market solution to one that is within the network constraints. In more detail, to implement smart markets, such as electricity generator dispatch or DM, we work with the tools of mathematical optimisation to solve a cost-minimisation problem. One concept that is central to interpreting the output of idea such mathematical optimisation problems is complementary slackness – that a binding primal constraint is associated with a positive price (dual variable), while non-binding constraints have price zero. In particular, the model used by the NEMDE is generally a reasonably crude linear approximation of select parts of the true physical system. Originally, a simplified model would have been necessary for computational reasons, but with advances in optimisation techniques and processing power, more accurate models are now possible.[1]

Looking deeper at the NEMDE, consider the treatment of frequency control ancillary services (FCAS). There are eight FCAS markets – raise and lower for regulation and fast, slow and delayed contingency response. Reserve markets are used for FCAS, because you can't run an auction for a response that is required within seconds. Indeed, FCAS are always required in a power system, which is another way of saying that the FCAS capacity constraint is always binding. Hence, FCAS capacity is almost always given a positive price (dual variable), regardless of how it is bought or supplied; however, in the NEM this reserve capacity is priced by running a reverse auction for it. When FCAS capacity is procured by auction in this way, the level of capacity is determined by sound engineering judgement, while the cost of the service is determined by the participants' bids. Additionally, the AEMO currently co-optimises generation and FCAS for least-cost system dispatch, so this is not a strictly energy-only dispatch rule (this approach is also used in many other electricity markets). Importantly, the FCAS markets are oblivious to the technology that is used to provide the services – it could be a synchronous generator, a large load or an aggregator of many small generators and/or loads. This makes the Australian FCAS markets very flexible, and able to respond to both the future growth of renewable generation and greater controllability of devices embedded in the distribution network.[2] Given the FCAS market's success and robustness in the face of technological change, it seems appropriate to construct a DMM based on similar principles.

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[1] To the best of our knowledge, there have been no comprehensive studies into how much if any benefit more accurate models would bring to the NEM.

[2] On this topic, UNSW have compared various FCAS market structures and rules in the face of increasing renewable generation; see:
http://ceem.unsw.edu.au/sites/default/files/documents/WIW13_Riesz-FCAS-2013-09-02a.pdf

Now reconsider distribution networks. In order to configure an operational distribution market, input and other cost factors, and the technical constraints prescribed by the physical system in conjunction with sound engineering principles, must be compiled into an optimisation problem. For example, network constraints could include:

- total power per phase,
- total current on each phase,
- total current on each line,
- voltage at each customer connection point, and
- phase imbalance.

If approached this way, the physical model encoded in the problem formulation will closely model the actual distribution network under consideration. The optimisation problem is then solved, giving an allocation of roles to different parties, such as real and reactive power injection/consumption schedules by DERs and network equipment states (e.g. transformer tap settings).

In particular, it is important that constraints like those above are included even if they are non-binding and have zero price, as (i) they may become binding in the future, and (ii) they are integral to the computation of the effect of power flows and other services delivered by DER on overall DN performance.

However, developing good models or representations of DNs is not so straightforward, because in the DM case there is even more uncertainty about the required model accuracy than in the case of generation dispatch. This is because:

- the future makeup and adoption of DERs is uncertain, and
- today even if DNSPs wanted very detailed network models, many of them simply just do not have the necessary data readily available.

In the CONSORT project, we are working with models that are as accurate as we can make them given the available data and computational limitations. A possible area of research within the project could look at how much the market solutions drop in quality as more approximate models are utilised.

In particular, initial simulations of the CONSORT Bruny Island network problem have shown that models of the unbalanced 3-phase nature of the network are needed otherwise more requests for network support are made than are strictly necessary, given the available resources and the constraint they are put towards overcoming. Also, in order to implement voltage control at the customer level, an approximation of the LV network will be necessary (along with MV feeder models), or derivation of local reactive control techniques that work in parallel to the DM.

3.2.2. Customers

Customer models depend primarily on what type of DERs they have available for use. The decisions on what actions to take either come directly from people themselves, or through some form of automated energy management system (EMS) on their behalf. Ideally, the signals that come from the market are appropriate for both types of decisions to take place, but we focus on the response of an EMS as we expect most people will want a hands-off approach (for most types of DER an EMS can make better decisions anyway).

A customer’s primary objective is to reduce their costs for consuming electricity and maximising the value they can get from their solar system. In the current system customers can optimise these factors are by shifting to a different retailer, changing to a time-of-use tariff, self-consuming more solar, investing in energy efficient appliances or by simply just using less energy. DERs such as battery storage provide customers with greater flexibility to achieve these goals and can be readily automated by an EMS. Other DERs introduce additional factors to the objective that an EMS should consider. For example, air conditioning systems can be controlled in response to market prices, but occupants will want to set a price on how much deviation in room temperature they are willing to accept.

The information feeding into the model of a customer is constantly changing, can be quite sensitive (e.g., revealing about the behaviour of the people consuming the energy), and can add up to a large amount of data. This is why in a DM the customer model is best utilised locally instead of being explicitly incorporated into the DM mechanism like the network model. However, because the network and customer models are not collocated, a one-shot market (as discussed in section 4.4) will typically produce suboptimal outcomes. A typical way of improving the outcome is to use an iterative market which allows refinement of decisions, which is the strategy that the CONSORT project has adopted.

This departs from the NEM somewhat, where the offers that generators supply to the NEMDE are effectively piecewise-linear cost functions (along with simple constraints such as ramping rates) which are designed to be a proxy for the generators true model. While generators can modify these cost functions to a limited extent prior to dispatch, for the most part the system is designed as a one-shot market. In a DM this approach would be impractical and only provide a very crude approximation of true customer models for the reasons discussed previously but also because of the huge numbers of potential customer participants, their diversity and because of the complicated state-based nature of many DERs as we will discuss next.

Battery storage and many household smart appliances are state-based in nature (e.g., battery state of charge) which makes them difficult to properly utilise without considering future events. In order for an EMS to effectively control them, it needs to at least have an estimate of the future market situation (say at regular intervals over a forward horizon of 24 hours). To deal with this the market can either provide a common estimate to all agents, or it can let all agents perform the estimation themselves. In the CONSORT project we adopt the former strategy, with the market not only iteratively negotiating actions with agents for the very next time interval, but also for a forward horizon of points so that all agents have a good estimate of what will happen in the future. A similar approach is undertaken by the NEMDE as it provides short-term forecasts for market to participants.

Returning the to the example of the treatment of FCAS, the required level of FCAS capacity during any scheduling interval in the NEM is dynamically adjusted according to system conditions, including active generation sets, forecast demand, transmission network congestion, scheduled line outages, weather, and so on. In practice, AEMO, as the NEM operator, have rules or algorithms for determining the required level of FCAS capacity given system and environmental conditions.

3.3. Co-optimisation of DN objectives

Capacity constraints, voltage levels, the costs of grid-connected distributed generation, and so on, all fit into a mathematical optimisation framework if their costs and operational constraints are correctly elicited and encoded. Nonetheless, advanced optimisation methods are necessary here, to solve harder classes of problems than are currently tackled by NEMDE, as the scale of the co-optimisation problem on distribution networks is significantly greater.

Moving beyond DN, there are also opportunities for consumers to influence wholesale market prices, e.g. to help overcome ramping constraints or provide frequency control. If not explicitly co-optimised at the DN level, these system-wide objectives should at least be compatible with DN operations if working in tandem. In many cases, this effectively consists of ensuring that the "secondary" optimisation problem's feasible region is a subset of the "primary" one's. For example, for the wholesale market at its simplest, it might be possible to simply run the NEMDE to generate wholesale prices, then run the DM based on these prices, and let frequency control make up any difference between the two. As frequency control operates on a different time scale to DM decisions, it can be considered as a two phase process. Note that this implicitly assumes that random variation in load and generation overwhelms any attempt to "optimise" DERs on the DN beyond a certain resolution. Conversely, such an approach would need to ensure that there are not any perverse incentives to play the two systems against each other.

3.4. Market mechanisms supporting the efficient operation of DNs

We have discussed mathematical approaches to solving DN co-optimisation problems. The models discussed above make a number of assumptions about the costs, benefits, and prices that DER agents face, and include all manner of network-specific particulars.

However, these methods solve the optimisation problem, but do not solve the economic problem of deciding the rewards for providing services. This is not straightforward, as there are several economic features flowing from these models that complicate the process of implementing an outcome via a market. The three most pertinent are:

1. The way DER costs may be used by the NAC algorithms to implement discriminatory pricing,
2. The strikingly different values that the same action has in different parts of the networks, and
3. The gap between the cost of using the NAC algorithms and opportunity value to the DNSPs.

The economic problem associated with a DMM can be neatly encapsulated as the question of determining the role of prices. Prices do not necessarily reflect costs, and even when they claim to, it is pertinent to ask "which costs?" In other words, does the market design aim to:

- reflect the marginal cost of providing a service in the short run,
- reflect the the expected long-run marginal cost of providing a service,
- incorporate some consideration of opportunity costs, or
- is it designed to incentivise behaviour and investment decisions that minimise long-run costs.

In theory, these all collapse to the same thing in perfectly competitive markets, but distribution networks are far from perfectly competitive. The reasons for this are:

- The monopoly DNSP is a monopsonist when purchasing services from DER,
- The DNSP likely has access to customer specific data, and
- DER themselves may be able to exploit their location on the DN to express market power.

Moving on to the first economic feature, one outcome of the above is that DNSP may be able to implement price discrimination, close to perfect first-degree price discrimination,[3] An example of this is battery use to provide congestion relief on distribution feeders. On the cost side, DNSPs have a good idea of the retail tariffs customers are facing, and also the degradation rates of the batteries that are installed by customers. From this they could infer a very good approximation of the reservation price for any given customer. This information could be easily used to implement first-degree price discrimination. In the DR setting, such prices convert all the DER owner's surplus into cost reductions for the DNSP. Although this corresponds to DNSP operational cost reductions, when choosing a market design, one needs to question whether the DNSPs should be able to do this, as it may limit the uptake of DER and thereby hinder the investment process.

Second, on the other hand, all other things held constant, both location and phase connection matter immensely to the *value* of the DR provided by a DER to a DNSP. For example, is has quickly become apparent in the CONSORT project that adding load relief to an unconstrained phase of an unbalanced feeder helps very little in overcoming a thermal constraint. As such, a uniform $/kWh price may not be desirable, as it is not reflective of value. The AEMC has often stated a desire to see more cost-reflective prices; accordingly, it must also be desirable to see value-reflective rebates paid for DR actions.

Third, the next-best option for a DNSP to satisfy its service delivery requirements is often to augment a feeder or employ a conventional generator (e.g. diesel). The question then needs to be asked whether the owners of DERs should be allocated some of the cost reductions over this next-best option. This was case made for Local Generation Network Credits. In particular, it is worth noting that the prices generated by the CONSORT project algorithms ensure the optimal use of DERs to minimise the DNSP's operational costs, but do not signal anything about alternative costs.

Finally, standard auction-design considerations of strategic interaction in the market need to be addressed by the final market design, but are not canvassed here.

[3] First-degree price discrimination is where a monopoly seller of a good know all buyers' reservation prices and charges each of them at this price, thereby converting the entire competitive consumer surplus into monopoly revenue.

4. Consultation Questions

4.1. Question 1

Do stakeholders agree with these definitions, or have any views on the project scope as a result of these definitions?

The AEMC seems to be aiming to demark short-run operation and long-run investment at the level of the technology installed. Specifically, it appears from the approach paper that passive devices are to be treated only as long-run investments, with no operational role to play.

This delineation may not work in the context of distribution network management, as investment in passive devices, by a DNSP or private customers, may be a necessary step to implementing a market-based solution. This is especially the case when sufficient local generation capacity is needed for a non-network solution to be viable and operated as a market. More on the effect of this is on the project scope is given below in Remark 1, but an illustration is of this effect is given below.

Consider, a DNSP that wants to employ both controllable and passive devices installed on a feeder in order to overcome a network constraint at least cost (e.g. imagine the case of Bruny Is without the pre-existing PV installations). For this outcome to materialise -- as a precondition for a DR market to be created for this problem by employing the services of the smart devices on the network -- the DNSP may be happy to subsidise investment in both battery-PV systems and PV-only units (or indeed other small, non-dispatchable generators, including cogen units and fuel cells that have fixed output levels or other constraining energy vector requirements, i.e. heat).

The restriction of the definition of DERs to only smart equipment, or the subsequent restriction of the project scope to DERs, removes these scenarios above from consideration by the project. This appears to be an unnecessary limitation.

4.2. Question 2

Do stakeholders support this project scope? Is there anything that has not been flagged for consideration that should be? Is there anything that should be excluded from the project scope?

A number of additional points of difference between transmission and distribution systems can be made:

- Distribution networks are more exposed to forecast load uncertainty than transmission and generation, as the numbers of customers for any single radial component are obviously lower and more prone to correlating effects.
- The average costs per customer associated with distribution is much greater than for transmission, warranting closer examination of DERs and the institutions that support them (which implicitly acknowledged by the AEMC by conducting the project).
- There is, at present, less sensing and information available about the distribution network than the transmission network.
- Considerations of changes to distribution network arrangements should consider issues pertaining to customer acceptance of the technology involved, the complications of unsophisticated actors participating in markets for distribution network services, and the risk to vulnerable and other customer segments (such as renters) of missing the opportunity to benefit from the markets that might be established.

On the last point, we note that there is little research on customer attitudes, perceptions, acceptability and trust of active DER systems with their homes and businesses. One of the key research components of the CONSORT project is to begin to fill this gap in understanding. We also note that there has been little analysis of the distribution of benefits across customer segments that a move to market-based implementation of DR systems may have. In particular, there is little doubt that different customer segments have vastly different opportunities to invest in such technology. Thus, consideration of the the private benefits that they might receive for their investment, versus that portion of any cost reductions that are kept as social benefits, is worth close scrutiny. It was precisely this concern that scuppered the recent *Local Generation Network Credit* rule change request (ERC0191). We intend to provide information gathered from the CONSORT project on these latter two issues to the AEMC's Retail Competition Review process.

Remark on definitions and scope

In the approach paper, the AEMC have stated a desire to apply, as far as possible, arrangements and procedures that mimic the NEM generator dispatch procedures and transmission system operations to a future distribution services market. This makes sense in terms of devising a distribution market model that is able to operate in unison with the existing market arrangements for dispatch and transmission. However, the following consequences need to be drawn out and questioned.

As part of developing an approach to distribution service markets that is consist with existing arrangements, DERs are defined as those devices with operational capabilities matching the timings NEM dispatch procedures. As such, the desire for consistency has been propagated up to the level of the technology installed, and is used to demark the project scope in terms of the DER definition.

The implication here is that any distribution market will apply only to short-run operations or management of distribution networks, and will not be directly involved in the investment cycle over the medium or long term.

This may raise a difficulty with respect to the suitability of operations-only markets, which is discussed below in contradistinction to the rationale for energy-only spot markets in the NEM. To begin, when designing the NEM wholesale energy market, a decision to implement an energy-only market was made, and capacity markets were not employed. One major reason for adopting this market design is that generators participating in the NEM have access to financial instruments that can be used to hedge exposure to uncertain events. The services exchanged through the NEM wholesale energy market are system-wide in extent. Thus, and importantly, the markets for energy derivatives, based on the energy spot market, are sufficiently large and liquid for them to efficiently support the exchange and sharing of risk across many players. For this reason, establishing short-term, or spot, energy-only markets are a sufficient *institutional* response to support efficient generation dispatch operation over the short-term and the long term investment cycle.

The same cannot be said of any hypothetical distribution markets, as it is unlikely that any particular market supplying distribution network services is sufficiently thick to support a set of derivatives markets, given their limited geography. Accordingly, a spot market for services, procured over the short term only, may not be a sufficient institutional response to the challenges of distribution network management.

Likewise, in order for the project to consider the allocation of risk between trading parties, the project's scope needs to consider contracting arrangements between entities that are investing in new devices and those that are purchasing services from them. This is especially relevant to the choice of market design and/or regulation, given the relatively unsophisticated nature of many electricity customers (compared to the risk-sharing arrangements between NEM wholesale market participants).

Thus, the restriction of the project's scope to smart energy devices and operational timeframes only should be removed by, first, **placing distributed generation devices within the project scope**, either by altering the definition of a DER or by rewording parts of Section 1.3 to extend the project's scope to considerations of passive distributed generation devices Following this, **capacity markets and/or markets for the exchange of longer-term contracts should be considered in the context of distribution services**. This stands in contrast to the current treatment of wholesale markets, but need not be inconsistent with it.

We acknowledge that these changes represent a significant extension of the proposed DMM project scope.

4.3. Question 3

Are there any other elements of a DNSP's role or current responsibilities that should be considered?

Given that the DMM will look at DERs, Section 2.3.1 should include considerations of access explicitly, rather than relying on references to it in existing technical regulations.

DNSPs also have an important role to play in collecting and providing information to market participants. This includes sensing and otherwise acquiring data, storing and verifying data, and sharing appropriate information. In particular, DNSPs also provide statements of opportunities for non-network solutions.

4.4. Question 4

Are there any aspects of the regulatory framework that are not set out in sections 2.3 or 2.4 but which should be considered through this project?

It remains to be clarified what contestability entails with respect to obligations on the DNSPs to:

- Provide access to networks,
- Ensure the transparency of markets and prices, and of existing contractual obligations, and
- Issues of probity when establishing new contract and market arrangements.

4.5. Question 5

Should the coordination of distribution systems with distributed energy resources be centralised under the direct control of one body? Or should it be devolved and performed in a tiered manner?

For computational and control reasons, the coordination of DERs must be tiered. It is very difficult to see how distribution network control can be implemented in a centralised fashion at a large scale without, for example, adopting crude approximations of the physical network or very simplified control heuristics, both of which will necessarily be suboptimal. Decentralised control will also go some way to addressing any privacy concerns that customers might have.

However the question may be asking whether some central body (equivalent to AEMO) manages the “distribution market” by directly interacting with DERs, or if they set the regulations and another tier of aggregators and DNSPs implement solutions for specific parts of the distribution system. In this case, there is no obvious reason why the existing DNSPs cannot transition to the role of providing a “distributed system platform,” to use the language of New York’s *Reforming the Energy Vision*. This may be preferable given the DNSPs role as planners and as keepers of network asset and operational information.

One caveat to this approach is that the regulations should enforce a degree of consistency across jurisdictions such that aggregators and others operating across different networks do not face excessive cost in developing site-specific solutions (i.e. as a way of minimising transaction costs). More on these considerations are provided in response to Question 10.

4.6. Question 6

Do stakeholders agree with the Commission's framework and these principles of good market design? Is there anything that the Commission has missed, or is unnecessary?

The question is posed with respect to six principles of good market design, enumerated in Box 3.2 of the approach paper:

1. *Facilitate effective consumer choice.*
2. *Promote competition where feasible.*
3. *Regulate to safeguard the safe, secure and reliable supply of energy, or where it would address a market failure.*
4. *Promote price signals that encourage efficient investment and operational decisions.*
5. *Ensure technological neutrality.*
6. *Prefer simplicity and transparency.*

There is a lot of flexibility of interpretation in these principles, which is appropriate given the forward-looking nature of the project.

However, two issues arise when designing markets have not been explicitly included, and which may sit outside the conventional positive economic framing, regarding distributional effects of market designs and the allocation of risk between trading entities.

Efficient (or near efficient) outcomes can typically be implemented by a range of market designs, at least in the allocative and productive sense. These designs differ only in how costs, benefits and risks are allocated between transacting parties. As such, **the project should consider the expected distribution of costs imputed by any market design**. Within this context, two key considerations stand out for close examination, namely:

- The interplay between the outcomes generated by a particular market design and **a DNSPs regulatory environment may act as a limitation on the feasible market implementations**. This may include rates of return on capital investment and allowances for operational costs determined by a regulator, or other incentive schemes, such as future versions of the *demand management incentive scheme* or *service target performance incentive schemes*.
- It is likely that in order to satisfy their technical regulation requirements, DNSPs will procure services from DERs. This leaves them in a position of a **monopsonist buyer**, and as such it may not be appropriate to allow them to express their full market power, from both efficiency and distributional standpoints.

Furthermore, the rate of technological change must be considered when it comes to designing a market that hopes to promote some form of **dynamic efficiency**. In particular, it is important that customers are able to access products and instruments that allow them to **share the risk of investing in DERs** when such devices are undergoing rapid evolution, and newer technology is frequently displacing old. In such settings, there may be a perverse incentive for DNSPs or other market participants restrict supply of risk-sharing options in order to transfer capital risk onto customers, who, as much smaller entities, may not be best positioned to assess and/or carry that risk. Such options also aid in signalling the future value of technology and support the process of price discovery, which is essential to the pursuit of allocative and productive efficiency.

4.7. Question 7

Are there any other issues the Commission should have regard to in considering possible market design options?

The market design employed will be limited by network, device and customer modelling choices, in that the representation of network components and DERs underlying any “dispatch-like” operational market affects the set of feasible market designs.

In large-scale systems, this choice is determined by **computational issues** and limitations regarding the procedures employed to solve any smart market. For example, the NEMDE used by AEMO relies on linearised cost functions, which are implemented as discrete bid increments. These are not truly accurate representations of generator costs, but are used in order to keep the dispatch engine computationally feasible.

Similar considerations of the tradeoff between computation and accurate representation of the underlying physics of distribution networks should be included as an issue for the AEMC’s consideration.

4.8. Question 8

Do stakeholders agree with the Commission's assessment of the technical impacts of distributed energy resources set out above in sections 4.1 to 4.8?

Regarding Section 4.1, the definition of voltage stability in the approach paper applies to the transmission level. Although it is often used to describe voltage related problem at lower voltage levels, that is technically incorrect. In other words, even though voltages in medium and low voltage levels might be out of bounds, that doesn’t mean that the system is unstable. That is because the devices that contribute to voltage stability (load tap changers and overexcitation limiters of large synchronous generators) are located upstream.

Regarding Section 4.5, power factor is defined as the ratio between the active power and the apparent power of a load. The latter depends on the reactive power of the load; the higher the reactive power, the lower the power factor. Because of the high reactance of transmission lines, reactive power cannot be transmitted over long distances, so it needs to be sourced locally. In other words, power factors of loads that are electrically far apart might be significantly different, so it is incorrect to talk about a *grid* power factor.

Furthermore, considering Sections 4.1 and 4.5 together: When talking about reactive power support provided by distributed energy resources, one needs to take into account electrical characteristics of the network. Lower (MV and LV) voltage networks typically have a high ratio between line resistance and reactance, which means that injecting reactive power to manage voltages can be ineffective. A more effective way to affect voltages on a network is via a combination of active and reactive power.

Section 4.6 seems to only consider reverse power flows, rather than including cases where demand has increased to a level where peak loads approach thermal limits of assets in a traditional “forward” operating sense. We would expect to see more problems such as this with the deployment of electric vehicles and increased electrification of heating and cooking loads. The same point can be made for aging assets that are de-rated.

In addition, regarding both Section 4.6 and 4.8, it is our understanding that protection equipment is often configured in such a way that reverse power flows through equipment like transformers are treated asymmetrically to conventional forward flows, and will trigger protection schemes before thermal limits are approached (as such flows were, in earlier times, considered only possible in the case of faults).

4.9. Question 9

Do stakeholders agree with the Commission's preliminary assessment of these opportunities, and possible solutions to address the technical impacts of distributed energy resources?

We reiterate the point that voltage stability, associated with rapidly changing supply / demand imbalances in the distribution network, relates to operation of the transmission network, and that voltage support through reactive power injection on LV and MV networks is ineffective at providing that stability. As such static VAR compensators are not suitable for deployment on these networks; nor are DERs embedded in these networks suitable for providing this type of service. Furthermore, in the list of technical solutions given, the list of DER capabilities should include not only reactive power and low-voltage ride through capability but also active power for frequency support and voltage support on lower voltage networks.

As per the outline given in Section 3, we make the point that many distribution network markets will be established for non-energy services, such as local voltage regulation and (predictable) discrete network congestion events. These services can be treated in a similar fashion to FCAS and other ancillary service in the NEMDE; that is, by constructing a market that supplies the services required to overcome an operational limitation, encoded in a mathematical constraint, at a price determined by bids offered by DERs and other service providers.

Given this, it is also worth emphasising that any market-based solution to an imbalance or technical limitation actually implements one of the other three ways of addressing the identified problem listed in the paper. The key benefit of using the market-based solution is that, if well designed, the elicited bids approach marginal costs, thereby allowing an efficient solution to be found.

4.10. Question 10

Do stakeholders have any initial views on who should be responsible for managing these opportunities, or implementing possible solutions to the technical impacts?

As noted above, there is a strong case to give the role to DNSPs, given their existing responsibilities as planners and as keepers of network asset and operational information. This will, nonetheless, entail changes in the way DNSPs operate and are regulated. In particular, changes to regulation that compel the DNSPs' network support services procurement process to become more transparent, open it up to contestable market forces, and standardise the procedures across all DNSPs are warranted.

For example, currently, network support service contracting processes are not conducted via pooled, visible and contestable markets. This hinders the price discovery process for these services, potentially preventing efficient patterns of investment in network and non-network solutions to overcome network constraints. This market structure may also enhance the market power of the monopsonist DNSPs. These barriers, whether real or perceived, to accessing fair network support payments for DERs appear to be one of the motivating complaints of the *Local Generation Network Credit* rule proponents. The validity of this complaint is not in question, and efforts should be made to support the integration of new DER technologies into the provision of network support services.

However, having made this suggestion, it is worth keeping in mind that any moves to a transparent market for network support services may require further, more radical, reform steps to be successful. These may include:

- establishing the DNSPs as independent network service operators and giving them responsibility for running market procedures defined in the NER;
- establishing a system of oversight by the AER; and
- possibly giving partial administration of the markets to AEMO.

Moreover, this process may also benefit by being coupled with other changes to the NER that facilitate the participation of aggregation services in the retail market, as distribution companies are not equipped to develop billing relationships with many small customers and may struggle to do so.

5. Glossary

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market operator
AER	Australian Energy Regulator
DER	Distributed energy resource
DMM	Distribution market model
DR	Demand response
DM	Distribution market
DN	Distribution network
DNSP	Distribution network service provider
EMS	Energy management system.
LV	Low voltage, typically 415V three phase/230V single phase
MV	Medium voltage, typically 11kV, 22kV or 33kV three phase
NEM	National Electricity Market
NEMDE	NEM dispatch engine
NEO	National Electricity Objective
NER	National Electricity Rules
NSP	Network service provider
TNSP	Transmission network service provider
PV	Photovoltaic generator, i.e. typically an embedded small-scale photovoltaic generator such as a residential installation