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Mr John Pierce
Australian Energy Market Commission
PO Box A2449
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Electronic Lodgement Reference - EPR0022

Draft Report Power of Choice – giving consumers options in the way they use electricity

Dear John

United Energy (UE) appreciates the opportunity to respond to the AEMC on the Power of Choice Draft Report.

The Draft Report sets out the draft recommendations to facilitate demand side participation (DSP). The recommendations form a package of interrelated issues, particularly in the metering area. The potential to reduce capital expenditure and defer augmentation via a demand response are supply activities expected of distributors in the regulatory frameworks. It is not clear how the various recommendations in the Draft Report will be implemented and how the interactions with other recommendations will be managed. UE welcome the opportunity to discuss these matters further with the AEMC.

UE's detailed response to the questions is in the Attachment, in summary:

- UE is supportive of timely and accessible energy and metering data to consumers and has highlighted some further considerations to clarify and improve the arrangements;
- The market for energy management services should be free and open to competition, it is important not to stifle the development of this market through regulation;
- Demand side participation (DSP) is a form of customer service that our stakeholders expect distributors to undertake, UE do not recommend limiting the distributors to prescribed circumstances;
- The Draft Report does not think through the various roll out models and its impacts on technology options and meter functionality against the NEO. In the limited roll out scenarios proposed, the AEMC need to understand that many of the smart grid functions are unlikely to occur;
- Under the contestable roll out proposed where there are multiple meter providers, meter vendors and firmware/software combinations it is difficult to envisage that interoperability and open access will be a practical, available and viable approach;
- It would not be unreasonable for retailers to adopt a bare minimum meter specification. UE consider that it would be imprudent that Victorian AMI meters with a fuller specification were removed. UE recommend that the NER should be amended so that it provides a right for the existing Distributor provided AMI meter to remain in place so that the network services obtained from the distributor device are able to continue and the retailer can install the market meter. This

approach allows the retailer to seek a more cost effective metering arrangement via the minimum specification and distributors would have the option of installing (or keeping) their remote communication device for network services;

- UE agree that work on the detail and practicalities of a partial contestable roll out approach is required and would welcome the opportunity to work with the AEMC on these issues as they may apply in Victoria;
- UE are open to and supportive of an approach that strikes an exit fee price with the remainder being rolled into DUOS for distributor provided meters (types 5, 6 and AMI);
- The AEMC should not underestimate the complexity of customer differentiation created through a user pays approach for some customers and a smeared metering charge approach for others, and the potential impact of unbundling charges at the customer level;
- Whilst the wholesale demand side mechanism proposed may be suitable for large commercial and industrial customers, careful consideration is required before this complexity has the potential to be introduced to residential customers. Any change in the billing arrangements to customers should not be underestimated; separating out network tariff and retail tariff (energy only) and billing the customers on two different consumption values for the same time period is likely to be complex to communicate;
- UE generally support the creation of demand response mechanisms and aggregated demand response but distributors need to manage network stability and voltage impacts caused by loads switching. UE agree that there should be further consideration of a trigger threshold, although this is not at the individual market participant/aggregator level, it is the combination of all players that may switch the load on a localised part of the network that establishes the threshold.
- UE consider that the proposed tariff phasing approach is too complex and has the potential to establish different arrangements for customers depending on the band they are in. UE agree with the Draft Report that any transition to cost reflective pricing should happen in an orderly and coordinated way, however this banding approach is also reliant on interval meters being installed for the band and possibly then different costs/contracting arrangements in line with the metering arrangement adopted. This has the potential to set up different treatment of customers for the same consumption depending on the rollout option adopted in the jurisdiction and the jurisdictional threshold adopted which may be complex for national retailers to manage.
- UE support sending price signals to customers and have developed a range of time varying tariffs over the last decade. Different networks may peak at different times of the day, there is a need to maintain flexibility of the tariff structure across networks due to these differences and also so that innovation is not stifled. UE do not consider that there is a need for central planning of network tariffs and interference through guidelines. UE also consult with retailers and consumers and do not support amending the NER to provide increased guidance.

Should you require any clarification on our response please contact me on (03) 8846 9856.

Yours sincerely

Verity Watson

Manager Regulatory Strategy

United Energy

Attachment

Facilitating consumer access to electricity consumption information

Timely and Accessible energy and metering data to consumers

1. What should be the minimum standard form and structure of energy and metering data supplied to consumers (or their agents)? Should these arrangements differentiate between consumer sectors (ie industrial/ commercial and residential) 2. When do you think it is appropriate for a retailer (or responsible party) to charge a fee for supplying energy and metering data to consumers or their agents?

UE are generally supportive of the key principles outlined in the section 2 summary in the Draft Report. It is important that consumers have a right of access, and control the sharing of, their energy and metering data. This is an important element to assist with customer engagement and empowerment so that customers can make informed decisions.

The AEMC recognises that existing provisions of the NER are unclear about whether distribution network businesses or meter data providers are able to provide metering data directly to customers. UE is supportive of the AEMC position that regulations should not limit consumers from accessing their data from a distribution business (or a metering data provider).

The overarching principle in the Draft Report is that the rules should be changed so that consumers have the right to access and share their electricity and metering data. Customers should be aware that the data exists and how they can access and share the data with 3rd parties of their choosing in accordance with explicit consent, privacy and confidentiality provisions.

The NER 8.6.1 provides that all registered participants must not disclose confidential information to any person other than permitted by the NER. NER 8.6.2 provides a number of exceptions to NER 8.6.1 and NER 7.7.

UE is supportive of the draft recommendations in section 2.3.1 and 2.3.2, however we believe that the AEMC also needs to consider the following:

- Amendments to NER 7.7 to clarify that the customer may request their metering data from the distribution network business and that they may provide the customer with their data, subject to customer authentication;
- The current NER 8.6.2 (c) consent provision is unclear as to who is providing the consent. Amendments to the NER 8.6.2 (c) to clarify that registered participants who need to comply with the NER may, where the customer consents, provide their data to 3rd parties. This would allow, with customer consent for a registered participant to provide customer metering data to a government (or their consultant) for trial purposes or policy development. This would also clarify that a registered participant is able to meet a customer request for data to be provided to any third party the customer engages for energy services; and

- Amendments to the NER 8.6.2 (b) to clarify that registered participants who need to comply with the NER are able to provide confidential information to sub-contractors in addition to employees and advisors. This would reflect the extensive outsourcing arrangements across the industry in order to achieve synergies and lower prices for customers. This would allow effective outsourcing arrangements for a registered participant whilst still ensuring that the confidentiality provisions in NER 8.6.1 are met.

The Draft Report suggests that a meter data provider may also be able to provide access to metering data to the customer/third party at a cost. The role of metering data provider is not a registered participant, there may need to be some further consideration relating to Chapter 7 and 8 to cater for this. Current drafting would suggest that unless the customer requests the data from their retailer under NER 7.7, the meter data provider is unable to provide the customer with the data. In addition the exceptions outlined in NER 8.6.2 do not apply to a meter data provider, only registered participants.

The Draft Report recognises that the availability of technology such as web portals and smart phone applications is improving data channels through which customers are able to access, view and use their data. UE supports a minimum standard form of data where the customer wishes to download data, however any standardised format requirements should not restrict the channels that may be used to engage customers in their energy management decisions. Both the data/technology channels to engage customers and the format of data provided in these channels should be left to evolve, any minimum format requirements should not be unduly restrictive.

The Draft Report outlines a number of areas for clarification on the charging arrangements for the provision of data. Any arrangements adopted for charging need to be fair and reasonable across the parties, including where metering data providers provide the data.

Market information to develop DSP products and services

3. Do you agree that general market information should be published on consumer segment load profiles to inform the development of DSP products and services to consumers? 4. Is AEMO the appropriate body to publish such information, or should each DNSP be required to provide such information particularly where data will be at the feeder level where accumulation meters are installed?

The Draft Report raises concerns about information asymmetries between parties, the AEMC considers that there may be merit in publishing broader market information about consumer load profiles. Such information may be seen as useful for the development of potential DSP products, promote general consumer awareness of energy use, and improve information for policy development.

UE is not opposed to the publication of de-identified energy profiles where they will be useful for product development. The value in this approach will be in appropriate definitions of the customer sector load profiles and how well they meet the energy services markets requirements for product development.

While AEMO do hold the interval meter data for all interval meters in the market for the purposes of calculating the net system load profile, AEMO do not necessarily have information relating to a connection characteristic. Examples of residential profiles may include: customers with/without hot water, customers without hot water and with/without solar panels. A simpler but possibly less valuable alternative may be to provide profiles based on customer type and stratified load eg generic residential customer profile for less than 20MW.

There should be consideration whether AEMO may be best placed for this level of segmentation or whether some level of segmentation already exists with the AER EnergyMadeEasy Portal which may be able to be published. Where the data is used for product development it would be useful of all retailers and energy service providers to have the same access to these profiles.

AEMO do not have feeder level load profile data, this would need to be provided by the distributor. UE is not opposed to publishing this type of feeder level data where there is a benefit and there are at least a few customers on a feeder to ensure confidentiality/privacy is maintained for an individual customer.

Energy services to residential and small business consumers

5. What specific criteria could be used to determine whether elements of the NECF (ie marketing code) apply to third parties providing DSP energy services to consumers? That is, beyond Australian Consumer Law?
6. What requirements should be in place for these third parties? For example, what should be the form of authorisations/accreditations?

The Draft Report notes that there needs to be a clear distinction between services that affect the consumers ability to get a reliable supply of electricity (eg services that might include disconnection) and those services that provide information on how to manage consumption.

What is considered energy management services may evolve over time and be packaged differently by different companies. The line between energy management services, demand side participation including appliance load control and distributor load control is unclear.

The Draft Report states:

> *'As noted, the NECF's primary objective relates to the sale and supply of electricity and gas. In regards to electricity, we do not consider that the test under the NERL for retail licensing or authorisations should be amended to include the 'sale of energy 'services'.'*[1]

The Draft Report also suggests that where a third party is providing energy management services directly to customers, the specific circumstances would need to be considered to determine the regulatory arrangements to apply. Where the service may be relating to energy efficiency or energy audits etc, these are able to be provided today and no regulation is required. UE believe that it is important to allow these markets to evolve, they should not be regulated.

The market for these side products should be free and open to new competition. Customers should be free to talk to who they want to, as such UE consider that these service providers should not be regulated and stifled.

[1] Ibid, p37

Role of retailers and distributors – engaging with consumers

7. Do you agree that existing rules and guidelines should be amended to clearly outline the circumstances when distribution businesses are able to directly contract with residential and small consumers to deliver DSP network management services/programs?

In the Draft Report the AEMC expresses the view that the AER guidelines under the NER or NECF should be enhanced to clearly outline the circumstances when distribution business are able to deliver DSP network management services and programs and what NECF provisions should apply. Further where network businesses undertake activities that are performed by a competitive market, they are required to do so through a separately ring fenced business. Appropriate cost allocation needs to be in place to ensure no cross subsidy with regulated activities and some sort of managed access to ensure that the distributor has no greater priority access to the service, information etc.

Distribution businesses provide supply, energisation and connection services. The economic framework is driving distributors to improve quality and reliability of supply, manage replacement of aging assets and to do so in a cost effective manner. Chapters of this Draft Report are devoted to distribution business demand side engagement and innovation programs to improve knowledge and methods of engagement for demand management, including possible methods for distributors to manage and reduce the needle peak demand.

It is difficult to envisage the increased level of incentive programs in relation to demand side participation and innovation likely to evolve in the regulatory framework whilst placing barriers and restrictions in the services that may be offered to customers by distributors. DSP is a form of customer service, customers and Senate Inquiries expect distributors to provide customer services and seek to ensure efficient costs. Stakeholders consider that distributors do not undertake enough DSP, UE recommend that the circumstances where we provide DSP should not be limited to prescribed circumstances.

Processes such as the RIT-D are expected to apply to distributors in the near future for network augmentation projects above $5m. Networks are expected to consider alternatives to investing in further capital and opportunities to delay augmentation. These directions in the regulatory framework to incentivise distributors to undertake/generate demand side activities is at odds with the constraints being proposed in this section of the Draft Report.

Distributors are likely to target DSP initiatives aimed at network constraints or future network constraints. It is difficult to envisage that DSP activities will be competitively provided in the market in the short term, particularly where there is a partial roll out of interval meters and where there are constraints on adopting efficient pricing.

UE consider that given that the AER has considerable oversight of distributors activities, review/approval of demand management initiatives and extensive information gathering powers that further additional impositions are not warranted at this time. Distributors do have a direct relationship with customers today and are bound by the Australian Consumer Law. There is no evidence of a market issue regarding distributor’s dealings with customers that would warrant further regulatory obligations.

Metering Considerations

Functional specification of meters in the NER

7. Should the minimum functionality specification for meters be limited to only those functions required to record interval consumption and have remote communication? Alternatively, should the minimum functionality include some, or all, of the additional functions specified in the SMI Minimum Functionality Specification?

The Draft Report suggests that here should be a minimum functionality (eg remotely read interval meters) for small business and residential meters and that this minimum functionality should be provided for all new connections, new and replacement meters and be mandated for large residential and small business with consumption above a certain threshold.

The National Smart Metering Program (NSMP) developed a minimum functional specification for smart metering infrastructure which is largely (but not completely) aligned with the Victorian smart metering specification. Given the extensive industry and consumer involvement UE suggest that this specification should be the base functionality considered for any new or replacement metering.

The additional costs of the HAN interface and Smartgrid functions in the meter are minimal compared to the costs of the meter and the installation. It is more efficient for these to be installed as part of the package as opposed to retro fitting these at a later date, subject to the value of these functions in the meter roll out model adopted. Some of these functions will be less valuable in a point to point communication technology solution vs an always on technology solution such as mesh radio.

The Draft Report does not think through the various roll out models and its impacts on technology options and meter functionality against the NEO. In the limited roll out scenarios proposed, the AEMC need to understand that many of the smart grid functions are unlikely to occur.

UE would expect that given the option of a bare minimum specification that retailers may opt for the bare minimum specification unless distributors pay. Given there may be numerous meter providers and permutations of meter vendors, firmware, various operational nuances with turning on functions, it may not be prudent for a distributor to seek to procure these services from a churning set of metering providers. Further a partial roll out is unlikely to enable any cost efficiency for distributors seeking network services given the volumes and the time to establish systems and processes with an individual vendor.

Where there are multiple meter providers, meter vendors and firmware/software combinations it is difficult to envisage that interoperability and open access will be a practical, available and viable approach.

It would not be unreasonable for retailers to adopt a bare minimum meter specification, however, given the above, UE consider that it would be imprudent that Victorian AMI meters with a fuller specification were removed. UE recommend that the NER should be amended so that it provides a right for the existing Distributor provided AMI meter to remain in place so that the network services obtained from the distributor device are able to continue and the retailer can have the market meter. This approach allows the retailer to seek a more cost effective metering arrangement via the minimum specification and distributors would have the option of installing (or keeping) their remote communication device for network services.

Whilst the Draft Report is aiming for open system and interoperability, if the meter was specified as the bare minimum of remotely read interval meter there could be significant interfacing costs and impacts on metering service provider competition. There are significant costs for an MDP to introduce a new meter/interface protocol to its IT systems. Adopting a common interface for data (interval data and control activities) will facilitate reduced costs for metering services and the non-metering services.

If the bare minimum approach were adopted for meter functionality after the Victorian derogation, the business case for Victorian AMI could be jeopardised as a number of the benefits arise on the network side and it may not be cost effective for the network to deliver these by developing and testing interfaces with a number of parties and differing technologies. In line with the above, UE suggests that the NER be amended to provide a right to the distributor to have the distributor meter remain in place acting as a remote network device. UE consider that this would also allow the distributor to continue to meet its energisation (re-energisation and de-energisation) obligations under NECF and understand supply related issues on the network, although the meter would just be a remote device in this case and not the market meter.

Arrangements to support commercial investment in metering technology

8. Does the separation of the provision of metering services from retail energy contracts remove the need for meter churn when a consumer changes retailer? Does this cause any unforeseen difficulties or create any material risk? Are there any alternative approaches to reducing the need for meter churn?
9. Are there sufficient potential metering services providers to facilitate a contestable roll out of AMI? Does the proposed model mitigate all the material risks of a contestable roll out? If not, should a monopoly roll out be adopted?
10. What should the exit fee when a consumer upgrades it meter from one provided by the local distribution business? Is the proposed fixed 30% of the cost of a replaced meter appropriate?
11. Does the option of a government mandating an AMI roll out within its jurisdiction act as a strong disincentive to a commercial roll out? Should the ability for these governments to mandate an AMI roll out removed from the NEL?

The Draft Report suggests that interval meters are critical for ensuring that large appliances (air conditioners, charging of electric vehicles) do not impose unfair costs on other consumers. The use of time varying tariffs will provide proper price signals to electric vehicles users to encourage them to charge their vehicles at off peak – or pay a fair price for doing so at other times. The Draft Report correctly notes that customers who are able to shift load to off peak times or have a less peaky load profile will benefit from time varying tariffs and are likely to be the customers to move to these tariffs. Customers with peaky load who might pay more on time varying tariffs may not change tariffs resulting in the flat tariff increasing for customers who wish to remain on the flat tariff as a safe haven or possibly due to customer disinterest in making tariff decisions. A slow roll out of smart meters/customer choice of smart meter and a customer choice of tariff will create a slow uptake of cost reflective prices.

Customer contracting for the metering provider

The Draft Report proposes that customers could engage their metering provider, allowing the meter to remain whilst they are able to churn retailer. Customers should be free to select the meter provider/meter however, it needs to be recognised that the meter is an essential tool for settlement of the wholesale market. Generator, retailer and distributor transactions rely on this tool in order for the NEM to operate. The meter cannot readily be disaggregated from this framework, it may be better for retailers or distributors to be responsible for meter provision (and select the meter provider).

The customer engagement of the metering provider needs further consideration;

- under this scenario churn of the meter would only be on the request of the customer or when the customer moves out, this would avoid some of the meter churn costs, more complex data management and possible lost data;
- the retailer would act as responsible person in the market and would be responsible for the metering installation and yet have no contractual arrangement with the metering provider engaged by the customer. The accuracy and maintenance of the metering installation would presumably rest with the customer and be reliant on the accredited metering provider doing the right thing. Where current transformers fail, the retailer would be responsible for ensuring that the site was bought back to a compliant state although the retailer may not be aware of whether the customer has contracted for the meter only or the whole metering installation;
- the retailer acting as responsible person would engage the metering data provider. In order for the remote communications to work correctly the communication card in the meter needs to be consistent with the requirement of the retailer’s meter data providers requirements and communication contracts. This is more readily coordinated today where either the distributor or the retailer is acting as a single decision maker across both metering roles. This single responsible person for both meter and meter data provision is consistent with the AEMC rule determination made some years ago to remove the MDA and AEMO tripartite deed arrangements for remotely read interval meters;
- customer decision making may be based purely on short term thinking or cheaper initial cost, this may result in more complexity in upstream processes and cost of deploying certain functionality or shorter meter life;
- whilst the customer may be able to choose to contract their own metering provider and choose the meter, how do they know who the accredited metering parties are? Would there be a significant communication campaign in a jurisdiction where this proposal was adopted to ensure that customers only utilise the accredited parties?

The Draft Report notes that customers are not likely to actively exercise this option of contracting the metering provider service directly themselves. However the Draft Report notes that metering would then need to be carved out of the retail contract, there would also need to be consideration of other aspects of the regulatory framework. UE consider that providing this level of optionality of customer choice has the potential to increase complexity in the regulatory/market framework and costs.

Whilst the customer contracting for the meter provider service avoids the need for meter churn when the customer changes retailer, it does not avoid the need for meter churn when the customer moves premises. Alternative approaches to this issue of meter churn are meter lease arrangements, distributor roll out or franchise metering areas. These were all considered by the SCER previously and after consideration by the SCER the amendments to the NEL to allow the Minister to make a mandated roll out decision were made. The option of mandating a rollout of smart meters should remain an option for governments, it is expected that any Government would not make a decision lightly and significant analysis would occur before any decision was made. UE suggest that the NEL amendment remain and consider that it would be useful to make a provision that any mandated roll out that may be adopted in future will not strand retailer's assets. This would remove this risk of asset stranding for retailers so that it would not act as a disincentive to assets installed in good faith.

Retail rollout

Apart from the next year in Victoria, there is nothing stopping a retailer choosing to offer a customer a remotely read interval meter today. If retailers choose to roll out to only 20 or 30% of customers, it should be recognised that there will be consequential costs on the distributors such as increased manual metering read costs as meter read routes become less efficient, a need to automate interfaces to the market to cater for MP and MDP churn, possible distributor involvement in unsafe wiring and site defects/disconnection processes, maintaining existing load control and accurate tariff application with a different meter and possible increases in billing complaints due to the complexity of metering configurations, meter register and data streams and application of tariffs (an example may be that the data streams provided are from a net metering configuration rather than a gross metering configuration). There may also need to be consideration of how the new and replacement approach will work where responsibilities are transferred at the same time.

The Draft Report presumes that metering competition and a partial roll out better serves the long term interests of consumers than a mandate/monopoly roll out within a geographic area. The contestable approach is favoured as meter provision does not have the characteristics of a monopoly services and the AEMC consider that it will drive innovation and metering services at a lower cost. UE agree that work on the detail and practicalities of this approach is required and would welcome the opportunity to work with the AEMC on these issues as they may apply in Victoria.

Exit fee/charging

The Draft Report suggests that there should be a standard exit fee when a network accumulation meter is upgraded. The AEMC propose that a standard fee will remove the need for negotiation between the retailer and distributor on the loss of value of the meter. The exit fee proposed is 30% of the cost of the replaced meter with the remainder of the meter value being recovered from all consumers through DUOS.

The 30% appears to be an arbitrary setting and may not suit all jurisdictions. UE are open to and supportive of an approach that strikes an exit fee price with the remainder being rolled into DUOS for distributor provided meters (types 5, 6 and AMI). As mentioned earlier in this response to the minimum metering specification, UE support the right for the distributor's Victorian AMI meter remaining in place with any competitively provided market meter being installed on the customer side. UE consider that distributors should have property rights and its meters should right to remain in place in order to facilitate the network benefits of AMI and network services such as smartgrid arrangements. UE don't support having our meters removed by third parties and welcome the opportunity to have the discussion with the AEMC and the AER.

There a number of issues with the approach in the Draft Report:

- Distributors have installed both accumulation and manually read interval meters, the Draft Report is unclear whether such an approach would be extended to type 5 meters or Victorian AMI meters which are currently type 5;
- All customers will be paying for their new metering services (user pays) or current (smeared) metering services and the shortfall costs of stranded meters which may increase costs;
- For mass market customers there is also a further equity issue that of moving from smeared metering and data management costs to one of a user pays model.

The AEMC should not underestimate the complexity of such an approach and the impact of unbundling charges at the customer level. Victoria has had unbundled metering provision and meter data provision charges from network tariffs for some time, however there was an adverse reaction when these were unbundled on customers' bills. A contestable roll out where some customers have bundled/smeared metering charges and others have forced/opted in for a user pays approach by receiving a new meter may have significant ramifications for communication. It is unclear how this arrangement would be presented on the customer bill, if at all. It is also unclear the level of transparency eg the AER Retailer Fact Sheet approach including exit fees so that customers are able to make an informed decision of their choice to move to a retailer provided remotely read interval meter, including retailer meter exit fees.

Demand side participation in wholesale electricity and ancillary services market

Demand response mechanism

12. Participation in the wholesale market: (a) Do stakeholders agree that the proposed demand response mechanism is likely to result in efficient consumption decisions by end-users? If not, are there any changes you recommend to the mechanism to facilitate this? (b) On balance, is a new sub-category of market generator required for consumers providing a demand that enables aggregation? What types of issues should be considered when developing the registration process? 13. Consumer baseline consumption: (a) What factors should be taken into consideration when developing a baseline consumption method? (b) Have we identified the correct three key principles for developing a baseline consumption method (data refresh, accuracy, metering)? (c) Are there any substantial changes to metering and settlement arrangements required for this mechanism to be implemented? Can these issues be resolved through AEMO's consultation process and procedures or are broader amendments to the rules required? 14. Incorporating demand response into central dispatch: (a) Do you agree that similar arrangements for generation should apply to demand resources in terms of thresholds for registering as scheduled or non-scheduled basis? (b) What are the ways in which the regulatory arrangements can be adapted to facilitate the participation of scheduled and non-scheduled load in AEMO's central dispatch process? Are there any specific changes to reporting, telemetry and communication requirements? (c) Should both market and non-market loads above a certain size be required to provide information to AEMO regarding their controllable (and therefore interruptible) load blocks? (d) Should there be a trigger in the monitoring and reporting framework that requires consumers to provide greater detail regarding their demand resource to AEMO or affected DNSPs?

The Draft Report recommends a demand response mechanism that rewards change in demand via the wholesale market. The recommendation is more suited to large commercial and industrial customers although the approach could be adopted at residential customer level.

In this approach a demand response would be able to be bid into the market and be paid the wholesale spot price for reducing demand. A number of aspects need to be worked through:

- Calculation of the baseline consumption for a site that would have occurred had there not been a demand response at the site by an independent party that does not have a financial impact; and
- The timing of the demand response in the field and the scheduling of dispatch arrangements.

The approach requires a new category of market participant, however it is unclear whether this new category of participant will require a retail licence in order to register in the category of market participant or whether aspects of the NECF relating to marketing may need to apply. Can an exempt retailer under NECF or any third party be a registered market participant in this new category?

The proposed approach requires that the network tariffs are applied based on the actual meter reading and the retail tariffs(energy only) are based on the baseline or calculated metering data (ie the calculated consumption if there had been no demand response). This requires the bill to the end customer to have unbundled network and retail tariffs and also to charge the customer based on two different consumptions for the same time period. This may be complex for small business and residential customers to understand. In addition there are likely to be changes required to retail billing engines to allow both network and retail tariffs to be billed and to receive/hold two different consumption values for the one premises.

Retailers would be settled in the wholesale market based on the calculated baseline consumption and the difference in the actual and baseline consumption would be paid to the new demand response market participant in order to fund a rebate to the customer.

Whilst this may be suitable for large commercial and industrial customers, careful consideration is required before this complexity has the potential to be introduced to residential customers. UE is by no means endorsing separating out the network and retail components on residential bills, however if this approach were to be adopted for mass market, there may need to be consideration of some preliminary steps before unleashing this level of complexity on customers. For example, a significant communication campaign regarding this level of tariff unbundling before moving to the complexity of billing each component based on a different consumption value.

The recommendation in this section of the Draft Report is to create a new category of market participant in order to unbundle non-energy services from the sale and supply of electricity. The Draft Report does note that existing retailers can easily fall into this new category of market participant, so there appears to be some linkage to the sale of electricity. Other sections of the Draft Report discuss the means by which distributors can be incentivised to undertake demand initiatives and be more innovative and how these arrangements may be regulated. The potential to reduce capital expenditure and defer augmentation via a demand response are supply activities expected of distributors in the regulatory frameworks. It is not clear how the various recommendations will be implemented and interacts with other recommendations, possibly reducing the overall benefits.

UE are supportive of a market working group considering all of the issues across the regulatory framework not just the wholesale market impact – baseline consumption calculation. Any change in the billing arrangements to customers should not be underestimated. The customer may sign up with the demand aggregator and it is not clear how the retailer or distributor are advised, provided time to amend retail contract arrangements and ensure that they have the billing capability.

This approach to demand side response is complex, the more complexity involved in a market potentially the harder the fall. If this type of demand response had a reasonable level of penetration, what happens if the demand response provider goes broke or exits the market, there could be catastrophic collapse of the market. This may pale in comparison to a retailer of last resort event and has the potential to impact reliability and security of supply.

If such a mechanism were adopted then there would need to be consideration of amending the Rule that requires distributors to bill on settlements ready data, NER 6.20.1 (e). In this case the settlement ready data is calculated data and UE understand that the distributor would bill network charges on actual metering data.

There may also be some issues creating financial transactions that are not based on measurable units with the potential that a financially impacted party could query the accuracy of the baseline data under the National Measurement Act.

If such a mechanism were adopted and resulted in large load shifts in a localised area this has the potential to impact the network and supply reliability. Whilst there may be a number of demand aggregators, individually they may have little impact but there is potential that the combination could create a more significant impact on the network. UE generally support the creation of demand response mechanisms and aggregated demand response but distributors need to manage network stability and voltage impacts caused by loads switching.

UE agree that there should be further consideration of a trigger threshold, although this is not at the individual market participant/aggregator level, it is the combination of all players that may switch the load on a localised part of the network that establishes the threshold.

Reporting requirements for demand forecasting

15. How should AEMO's powers be expanded to improve demand forecasting? Should retailers and other market participants be obliged to provide information regarding DSP capabilities? Will non-obligatory requirements achieve the desired accuracy in reporting requirements?
16. In what ways can AEMO improve its survey questions regarding DSP capabilities? How often should AEMO be required to update its expectations on DSP capabilities in the NEM?
17. Would a pre-dispatch that includes active and price-responsive DSP improve decision making processes for C&I users and aggregators? If not, do you have any other suggestions for improving the ability for AEMO to accurately forecast demand?

The Draft Report is proposing that AEMO's role be expanded to cover long term and short term demand forecasts inclusive of this new demand response mechanism and to update these on a regular basis. To facilitate such an approach AEMC consider that the information gathering powers of AEMO be extended so that an obligation can be placed on all market participants to provide data on request to AEMO to effectively perform its function.

The Draft Report suggests that with the likely increase in the level of DSP in the market there are a number of benefits of improving demand forecasts. The AEMC considers that these demand forecasts can be used to ensure efficient investment in assets in regulatory processes and network price determinations. UE is concerned with the creation of such a central planner approach in AEMO. AEMO generally undertake a top down rather than bottom up build, this type of approach should not go beyond its market use/status.

UE is concerned that if the forecast penetration of DSP does not occur as planned, and the extent of DSP on the day required does not eventuate, networks will not have the capacity to meet the needs of consumers for a safe and reliable supply. There is no obligation on AEMO to forecast accurately and bear the financial consequences and reputational damage that may result if the DSP did not eventuate when required after days of heatwaves.

Creating new category of market participant

15. Do you agree that a new category of market participant should be established for the provision of non-energy services?
16. What types of issues should be considered when developing the registration process, such as eligibility, obligations and liabilities?
17. What metering arrangements need to change to implement this mechanism?

The Draft Report recommends that a new category of market participant be created in the NER that will enable the unbundling of all non-energy services from the sale and supply of electricity and potentially a new sub-category of market generator to accommodate demand resources participating under the proposed demand mechanism. This will allow third parties such as aggregators to coordinate ancillary services independently of the customer's retailer or network business. Entities registered under this category would have the option to present to market on an aggregated basis within the region. Current market generators and market customers would be exempt from having to register in this new category.

AEMC considers that it is feasible that the small generator aggregator framework could be used to accommodate demand resources participating under the proposed demand mechanism.

UE are supportive of new roles being created to enhance demand response activities noting the concerns regarding these arrangements for residential customers.

The issues outlined in the Draft Report to be considered are reasonable. UE also recommend that the obligations and liabilities area must also include the impacts of load switching on the distribution network to ensure that the quality and reliability is maintained.

Efficient and flexible pricing options

Building Consumer Confidence through Education

The Draft Report recommends that government and industry work together to educate consumers and provide them with information they need to understand both the system wide benefits and potential individual gains from time varying tariffs.

UE agree that it is important for customers to have enhanced information about their energy use to better understand their consumption patterns and their impact on bills. Communication to customers should be managed in a way that provides customers with consistent or aligned messages. In terms of pricing to customers and a move to time varying prices, UE consider that it is retailers who have the commercial incentives and should undertake the communication to customers.

Managing the impacts on vulnerable customers

The Draft Report recommends that Government programs target advice and assistance to consumers in order to manage their consumption, review energy concession programs and provide arrangements that allow customers with a limited opportunity to respond to time varying prices to remain on a flat tariff.

UE strongly support concessions frameworks and hardship schemes being in place to support vulnerable customers during a transition to time varying pricing.

The Draft Report notes that many vulnerable customers may in fact benefit by moving to time varying pricing. UE is concerned that the flat tariff is seen as a safe haven tariff as there is a belief that it is always a lower cost option. If the flat tariff were charged at the same rate as summer peak price all year round this would not be the case.

Phasing in time varying pricing

18. Do stakeholders agree with our approach for phasing in cost-reflective pricing? If not, how can the policy be improved to transition to cost-reflective pricing?
19. Have we identified the main issues with transitioning to cost reflective pricing? If not, what other issues need to be considered?
20. How should consumption thresholds be determined?

The Draft Report proposes that residential and small business customers are segmented into three bands to allow a gradual phased approach to better price signals in the NEM:

- Band 1, large customers, the network tariff must be a time varying tariff;
- Band 2, medium to large customers, these customers would transition to a retail price that would include a time varying network tariff, customers would have the option of opting out to a flat tariff
- Band 3, small to medium consumers would remain on a flat network tariff, these customers would be able to opt in to a retail offer which includes a time varying network tariff.

Under this approach, retailers are free to choose how to include the relevant network tariff into their retail offers. The Draft Report envisages that service providers will want to offer customers a time varying package which include both upgrading their meter and introducing a time varying tariff.

The Draft Report notes that more analysis is needed on the design of the time varying network tariff and the pricing or the degree of cost reflectivity, as the pricing can have a significant impact on customers. The Draft Report also notes that further work is required on how the flat network tariffs is calculated, hence the need for more significant network tariff guidelines in the NER.

UE would be concerned with the potential that distributors are straightjacketed into one certain time of use pricing in the medium to long term as this will stifle more innovative network tariff offerings to customers. If the one size fits all approach is used, then the total costs of supplying electricity could just be smeared evenly across all customers making interval meters and cost reflectivity redundant.

The wholesale component of the retail bill could be around 30-50% of a customer's bill. Retailers are able to manage the risks associated with the significant variability in wholesale pool price ($-1000 to $12,000MW/h) and variability in the consumption level. The network tariff has significantly less variability at $70-$180/MWh for peak network use of system charges. UE don't consider that a straightjacket network tariff is required given the stability of network charges; each distributor should be able to choose a network tariff structure that provides reasonable cost signals.

As stated in the Draft Report, the retailers are free to pass the time varying network tariffs on by utilising a similar retail tariff structure or a flat tariff.

UE consider that the proposed approach is too complex and has the potential to establish different arrangements for customers depending on the band they are in. UE agree with the Draft Report that any transition to cost reflective pricing should happen in an orderly and coordinated way, however this banding approach is also reliant on interval meters being installed for the band and possibly then different costs/contracting arrangements in line with the metering arrangement adopted. This has the potential to set up different treatment of customers for the same consumption depending on the rollout option adopted in the jurisdiction and the jurisdictional threshold adopted which may be complex for national retailers to manage.

The Draft Report has provided no clear direction on the thresholds quite purposefully. When considering the banding arrangement in conjunction with the roll out proposal in the Draft Report it would appear that the threshold for requiring an interval meter is at the upper limit of band 3 and above. There are already a number of thresholds in the industry which could be utilised, although none are nationally consistent:

- Minister establishment of the upper limit of a manually read interval meter in the market could be used to establish the upper bound of band 1. This limit is set in the National Metrology Procedure. A separate decision would be required for band 2.
- The NECF adopts three bands for business customers, these bands could be used to establish the three bands. Although whilst NECF is a national customer framework, each jurisdiction has adopted their own thresholds.
- The NMI classifications in MSATS relate to small and large customers. This may provide a useful upper or lower limit for band 2.

Once the transition period has reached an end when a small customer moves from band 3 to band 2 and the customer is on a flat retail tariff and flat network tariff, how will this be managed? Is there a requirement to notify the customer and advise that the underlying network tariffs is mandated to a time varying tariff and the retailer tariff varies accordingly or remains on flat? Or will it be presumed that the customer has opted out of a time varying tariff on band 2? UE suggest that any management of movement between bands be quite flexible beyond the introduction/transition period. Retailers are best placed to manage offerings to customers without regulatory interference regarding the price structure of the offer.

21. We seek stakeholder comments on appropriate pricing principles for distribution businesses and the appropriate time period for stakeholder consultation on distribution network pricing proposals.

As noted earlier in our response, the Draft Report correctly notes that customers who are able to shift load to off peak times or have a less peaky load profile will benefit from time varying tariffs and are likely to be the customers to move to these tariffs. Customers with peaky load who might pay more on time varying tariffs may not change tariffs resulting in the flat tariff increasing for customers who wish to remain on the flat tariff as a safe haven or possibly due to customer disinterest in making tariff decisions.

The Draft Report raises concerns that the NER 6.18.5 (a) (2) could be used to shift costs from responsive customers to unresponsive customers. This sentiment suggests that flat network tariffs should be set depending on whether the retail customers for those tariffs are able or likely to respond. The thinking appears to be aimed at ensuring that the customers who are responsive and benefit from time of use, who are receiving a more cost reflect tariff should commence cross subsidising the unresponsive customers on the flat tariff.

The Draft Report proposes that the AER establish distribution pricing principles or guidelines that cover;

- Distributors applying tariffs in a manner consistent with the three band approach if this is the approach adopted;
- The requirement of the network tariff to signal the time varying nature of network costs and in particular how a consumers demand drives network investment;
- The possibility that drivers of network cost may differ from wholesale costs and thus a different tariff structure may be appropriate; and
- The range of possible tariff options which provide a more efficient signals eg CPP in a localised area of network constraint.

UE support sending price signals to customers and have developed a range of time varying tariffs over the last decade. These tariffs include demand components. Different networks may peak at different times of the day, there is a need to maintain flexibility of the tariff structure across networks due to these differences and also so that innovation is not stifled. UE do not consider that there is a need for central planning of network tariffs and interference through guidelines. UE do not support amending the NER so that distributors have sufficient guidance to set efficient and flexible network tariff structures that support DSP.

The Draft Report also recommends that the NER be amended to require distributors to consult with consumer groups and retailers on their proposed tariff structures each year.

UE already engage with retailers prior to the annual tariff submission each year. Where UE is changing tariffs structures UE hold several information sessions with retailers in order to provide some insight into the tariff strategy and why the new tariff is being proposed. UE also has a follow up session with retailers when the tariff structure and pricing is firmer prior to the annual tariff submission. Once the annual tariff submission is lodged with the AER, UE provides copies to retailers of the proposed tariffs.

Where UE changes the tariffs structure, UE has also held one on one sessions with a number of consumer groups to explain the strategy and seek feedback. UE also run through the annual tariff submission in the customer consultative committee each year.

The Draft Report suggests that the AER may require a longer period to allow for consultation with external stakeholders on the structure of the network tariffs and as such is suggesting that changes be made to the annual tariff setting process to give the AER sufficient time to undertake this role. UE are concerned with such an approach if the date of submission were bought forward, as the quarterly CPI value is only available in the third week of October. If the date were bought forward this would require using an estimated CPI figure with potential re-submission of a further set of tariffs in quick succession.

UE concur that it is appropriate that retailers and consumer groups have some role in reviewing network tariffs. The Draft Report notes that retailers have greater experience and expertise with respect to types of tariffs that will suit consumers and are recommending a more formal reviewing role for retailers and consumers in the network tariff setting process.

UE note that the formal role of consumers and retailers is akin to a large supermarket chain setting the trucking contract for an ingredient that makes up part of a can of soft drink they sell. When buying the can of soft drink, the customer or the supermarket chain only cares about the price they see and not the underlying trucking cost of one of the raw ingredients. As such UE consider that the level of consultation that is already undertaken, particularly consultation on tariffs structures that is undertaken over 6 months prior to the implementation of the new structure is sufficient. Distributors should be able to propose cost reflective tariffs for their networks and have greater experience and knowledge of the network cost drivers.

The Draft Report recommends that where customers are on a time of use network tariff and have interval metering that the interval data is used for settlement in the wholesale market. If the customer were to revert to a flat retail tariff the recommendation is to continue to settle the market using interval data and not revert to the net system load profile. UE supports this approach which is current practice.

Distribution networks and distributed generation

22. Would it be beneficial to include reference to the suggested mechanisms and provide more guidance and an overall objective in the Rules governing the demand management incentive scheme?

The Draft Report recommends that the AER consider reforming the application of the current demand management and embedded generation connection incentive schemes to provide an adequate return for DSP projects which deliver a net cost saving to consumers.

In the Draft Report two factors are considered:

- The scheme should not be applied in a manner that prevents DSP from becoming part of normal planning and business practices; and
- It should not reward a business for doing DSP without corresponding benefits to customers.

The ENA has provided the AEMC with a report on the Incentives for Network driven DSP as part of their response which covers many issues.

UE recognise that the AEMC wishes a scheme to reward exceptional performance. UE are generally supportive of incentive approaches, however UE have a number of concerns regarding this approach:

- Business as usual and exceptional performance need to be well defined; Normalisation of weather/temperature, state of the economy, time of year, confidence levels in the electricity industry etc may all influence the level of exceptional performance; and.
- The need to meet an exceptional performance hurdle may inhibit development of such schemes due to the risks of recovering costs.

23. Should separate provisions for an innovation allowance be included into the rules? Given that the costs of the allowance would be borne by electricity consumers, is it more appropriate for such innovation to be funded through government programs?

The AEMC considers that a framework that provides the AER with discretion to apply an innovation allowance remains appropriate. However the Draft Report notes that a cost recovery mechanism may not sufficiently incentivise innovation as network business are not able to capture a share of any associated long term benefits.

UE is supportive of a framework that caters for an innovation allowance, although given the media attention on energy prices and the energy affordability concerns, UE suggest that innovation projects be funded though government programs.

Possible Application of DMIS to the transmission network business

24. Should the provisions for a demand management incentive scheme be included in the regulatory framework for transmission businesses?

UE do not consider that it is necessary to apply demand management incentive schemes to transmission businesses. Transmission charges are capacity based charges reflecting the highest capacity used by the distribution networks. Transmission businesses have no opportunity to control load and managed a demand response.

Network tariff structure influencing incentive to do DSP

25. What amendments are required to the current distribution pricing principles as set out in clause 6.18.4 of the national electricity rules?

NER 6.18.4 covers the principles governing assignment and re-assignment of retail customers to tariff classes. The Draft Report raises concerns regarding a high variable time of use tariff which may expose networks to greater revenue risks from demand fluctuation. Based on this concern the Draft Report raises the possible merit of including such tariff based DSP projects into the foregone revenue component of the incentive scheme.

UE has volume risk in its tariffs/revenue now under a price cap. UE are supportive of the AEMC view that changing the form of regulation from price cap to revenue cap is not the appropriate answer.

Where the retailer has a choice of network tariffs within a tariff class, the application of the principles in 6.18.4 (a) (2) and (3) which appear reliant on a one to one relationship of suitable network tariff for a certain type of customer within a class is an interesting one. These aspects are not well aligned to providing a choice of network tariffs to retailers for selection as opposed to distributor application of network tariff.

UE do not consider that changes to NER 6.18.4 are warranted at this time.