ETSA Utilities

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Mr John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
Sydney South, NSW 1235

9 May 2012

Dear Mr Pierce

Power of choice review – Directions Paper

ETSA Utilities welcomes the opportunity to comment on the AEMC's Directions Paper in relation to encouraging demand side participation (DSP) in the National Electricity Market.

In responding to the paper, ETSA Utilities has focussed primarily on how the greatest value can be achieved from network businesses involvement in DSP and/or where work we have undertaken has provided insights that may better inform the overall debate. We have deliberately remained silent on issues relating primarily to other market participants.

We note that although DSP represents a significant opportunity, it will by no means 'solve' the issue of high electricity pricing. For example, even if peak demand growth could be reduced to zero at no cost, this would only reduce ETSA Utilities capital expenditure by around 25%. This being the case, and assuming negligible impact on operating expenditure, even with 10 years of zero peak demand growth, customers' price increases would only reduce by 5 – 10% over those that would otherwise occur over that period. This is not to say that we should not continue to pursue DSP, but we must remain cognisant of the scope of potential benefits.

We also note the comprehensive discussion of distribution business profit incentives contained in the AEMC Supplementary Paper to this review. Without material incentives that deliver returns to owners above and beyond those available for low risk traditional infrastructure, and the removal of current disincentives, distributors willingness to embrace DSP will be limited.

This covering letter sets out the issues and/or directions that we consider to be most material in order to gain greater value from DSP. We have also provided a detailed response to the AEMC's specific questions which is attached.

Role of Pricing

1. A gradual transition toward more cost reflective pricing for smaller customers is considered an important pre-requisite for efficient DSP from a distribution network perspective. For the South Australian network, ETSA Utilities considers that capacity (peak demand) based tariffs, rather than time of use pricing or other tariff options, will generally provide the greatest cost reflectivity. Such pricing is also essential to ensure efficient investment in new customer side applications such as electric vehicles.

2. A transition to such cost reflective tariffs will require enhanced metering technology at the customer's premise. Smarter meters are also critical enablers of other aspects of DSP including import/export metering, gathering of customer demand data and enabling technologies such as direct load control (DLC) that we consider are key to extracting DSP benefits. We note that an ability to perform interval metering (for example, half hourly reads) enabling time of use tariffs *could* be a feature of such smarter meters, but is not necessarily a required feature to ensure distribution cost reflectivity.
3. Government may be required to play a role in subsidising vulnerable customers if they are seen to be significantly disadvantaged by more cost reflective approaches.

Customer participation

4. ETSA Utilities considers that distributors are best placed to roll out and operate the smart metering infrastructure required to support DSP. We see no benefit in introducing new market participants to undertake such a role when distributors:
    - Have an existing relationship with customers in undertaking such a role;
    - Can leverage our existing systems, capabilities and experience to undertake such roll-outs;
    - Can gain significant value beyond DSP from smart meters, such devices being a critical component of the future automation across network infrastructure (ie 'smart grid'); and
    - Can provide open access to smart grid capabilities and data to allow other participants who wish to leverage these capabilities to add further products and value to customers.

    A distributor led roll-out will minimise costs to customers whilst maximising customers' benefit and value.

Supply chain

5. Incentive mechanisms for DSP must enable a participant willing to pursue an initiative to extract benefits across the entire supply chain. The absence of such mechanisms will inappropriately stifle a range of initiatives having the potential to significantly benefit the community.
6. The ENA has proposed alterations to incentive mechanisms to facilitate such benefits extraction. ETSA Utilities strongly supports these proposals.
7. In addition to the ENA's proposal, ETSA Utilities considers that current impediments to distributors bidding generation, stored energy or demand response into the NEM should be removed. This could be limited to instances where such resources have been commissioned primarily for network support.

Networks

8. Significant disincentives exist for distributors to undertake efficient DSP rather than constructing traditional network solutions. In particular, such solutions typically have higher levels of risks associated with them and may reduce the distributor's revenue and/or returns under some forms of control. Although some of these disincentives are economically appropriate, for example, the need for the distributor to appropriately manage risk, some fine tuning of the current incentive mechanisms would assist in removing artificial barriers.

9. Once again, the ENA has proposed alterations to incentive mechanisms to facilitate such benefits extraction. ETSA Utilities strongly supports these proposals.

Other issues

10. We note that as DSP technologies mature, and in particular, the cost of local generation and storage technologies reduce, it is likely that 'off-grid' energy solutions will become cost and performance competitive with 'on-grid' solutions. At such time, a competitive market for electricity 'distribution' will have been created and thus more light handed regulation will be warranted. Significant consideration should be given to the regulatory implications of such a future.

ETSA Utilities would be pleased to meet with representatives of the AEMC to further discuss the issues raised in this response.

Should you have any further questions in relation to this submission, please contact Wayne Lissner on (08) 8404 5391.

Yours sincerely

Sean Kelly

Sean Kelly

General Manager Corporate Services

Question	Response
Chapter 4 - Consumer engagement and participation	
Access to energy consumption - load profile data 1. What should be the arrangements for consumers (or third parties acting on their behalf) to access their energy data? 2. Do you consider that there could be a role for an information service provider in the market as a mechanism to provide consumption data to consumers? 3. Should amendments be made to the current NER clause 7.7 (a) to facilitate consumer access to consumption information? If so, how?	Customers (or third parties acting on their behalf) should have access to their energy data (both consumption and peak demand where available). As a distribution business ETSA Utilities is well placed to provide customers (or third parties acting on their behalf) with access to their energy data in a secure and cost effective manner – be that via web portals, in-home displays, mobile devices or via a value-adding third party (eg. retailer or ESCO). Although it is possible to set up a separate information service provider in the market to facilitate this, it could be inefficient or impractical and set up yet more supply chain inefficiencies and the limited potential gains (refer also response to question 17 with respect to the scale of potential benefits). Further, we note that distributors already have significant capabilities and experience in the management of customer demand data, and will need to gather and manage this data for their own purposes in any case. An important note to add is that providing customers with their energy data in itself will not ensure sustained behavioural change. It is only when customer engagement is combined with appropriate price signals/incentives, education, and enabling technology that the impact will become material. Clause 7.7(a) would appear to provide barriers to non-participant ESCO's acting on behalf of customers to provide (for example) advice and/or solutions to enable them to better manage their energy consumption. Guidelines surrounding such access will require significant consultation and ETSA Utilities would prefer not to comment on specific potential amendments at this time.

Costs of consumption decisions 4. What information provisions could be put in place to improve awareness of the costs of consumption and the use of particular appliances/equipment, so that the benefits of taking up different DSP options can be realised?	For DSP to become a reality, public engagement will be paramount to its acceptance and success. There is a significant gap between the understanding of the public and the reality of the cost drivers of electricity. In the future, as technology matures, improvement in the awareness of DSP amongst the public may well be promoted through the dissemination of in home displays (IHD), home area networks (HAN) and energy management systems (EMS). However, in the interim it should be the responsibility of retailers, network businesses and potentially the government to educate consumers about the potential benefits DSP. Although retailers are traditionally tasked with facilitating the interaction between the consumer and the market, they do not necessarily have the in-house expertise and information required to communicate network specific DSP benefits. Thus both retailers and network businesses will need to engage their customers (separately or in partnership) to effectively realise the benefits from DSP. Further to this, the government could play a role in educating consumers in partnership with industry. Government may also be required to play a role in subsidising vulnerable customers if they are seen to be significantly disadvantaged by initiatives like more cost reflective tariffs. The ETSA Utilities residential CPP trial that was identified in December 2009 as part of our DM program of trails was difficult to implement due to the very poor response from potential participants leading to very low trial numbers. We must recognise that some customers, for various reasons, will just not care. However, for those that do wish to understand potential strategies to reduce or manage their costs, appropriate information must be available. Although mandatory information provisions are not considered necessary, as per our response to question 3, we consider that third parties should be enabled to gain access to this data in order to mine potential additional value for customers.

Chapter 5 - Efficient operation of price signals	
Network pricing and incentives 5. Should network charges vary by time of use? 6. Should NSPs charge on a volume or capacity basis? 7. What changes are needed to market conditions to facilitate more cost-reflective network pricing?	A gradual transition toward more cost reflective pricing for smaller customers is considered an important pre-requisite for efficient DSP from a distribution network perspective. For distribution networks, capacity (peak demand) based tariffs generally provide greatest cost reflectivity. Such pricing is also essential to ensure efficient investment in new customer side applications such as electric vehicles. The main stumbling block up to this point for such a transition has been the cost of smarter metering required to implement these tariffs. However, if the cost of these devices reduces sufficiently and other market benefits can be accessed by the network business to justify the installation of smarter metering this will be less of an issue. Smarter meters are also critical enablers of other aspects of DSP including import/export metering, gathering of customer demand data (to better inform customers, network business and retailers) and enabling technologies such as direct load control (DLC) that we consider are key to extracting DSP benefits. Broadly speaking, the residential tariff innovations currently being considered by distributors worldwide include: (i) **Inclining block energy**: whereby the customer is charged differentially for each 'block' of energy they consume over a certain period (generally 3 months). This approach uses total energy as a crude proxy for peak demand, thus attempting to charge large customers more for their (assumed) higher peak. This is how ETSA Utilities currently bills its residential customers. (ii) **Time of use energy**: whereby the customer is charged a higher rate for energy used during times when the cost of supply is higher. For a distributor, this would generally mean a higher price during peak demand periods (eg from 2pm to 8pm). (iii) **Critical peak pricing**: whereby the customer is charged a very high rate for 4 to 12 specific 4 to 8 hour periods each year when the network is constrained. Such periods are generally signalled in advance to customers the day prior to the event via SMS or in-home display. (iv) **Capacity**: the customer is charged based on an agreed or measured maximum demand over a given period. (v) **Various combinations** of the above.

In evaluating the effectiveness of tariffs in appropriately signaling customers and taking a broad value chain perspective, many factors must be considered, including:

- Revenue volatility (for the market participant)
- Bill volatility (for the customer)
- Generation cost reflectivity
- Distribution cost reflectivity – NSW/Vic/QLD climate
- Distribution cost reflectivity – SA climate
- Complexity

These factors are summarised in the table below.

Option	*Low revenue/bill volatility*[1]	*Generation cost reflectivity*	*Distribution cost reflectivity*	*Likelihood of reducing peak*		*Complexity*
				NSW	SA	
Inclining block energy	Poor	OK	Poor	Poor	Poor	OK
Time of use energy	Poor	Good	OK	OK	Poor	OK
Critical peak pricing	V. Poor	Good	OK	Good	Good	Poor
Capacity	Good	Poor	V. Good	Good	Good	OK

It is our view, at least in the South Australian context, that energy related tariffs are poorly reflective of distribution costs, whereas critical peak and capacity tariffs reflect distribution costs much more effectively.

[1] This refers to distribution revenue volatility and customer bill volatility due primarily to weather volatility in South Australia.

In particular, ETSA Utilities considers that time of use tariffs are not a very effective means of reducing the distribution peak in South Australia as we have very peaky localised load (i.e. not always concurrent with system peaks) driven by air conditioning for a few days a year – therefore a very large differential would be required between peak and non-peak prices (similar to CPP) to suitably deter customers from using their air conditioning during heat waves – particularly if they are extended.

Such a large price differential would lead to significant bill volatility for the customer and revenue volatility for the DNSP. For example, in a year with a number of large heat waves and therefore a high demand and price, customers' bills and the distributors revenue could be very high. In a mild year, bills could be very low. This is considered undesirable and unacceptable and does not accurately reflect the underlying cost drivers to a network.

On this basis, we consider that capacity tariffs represent the most promising cost-reflective network pricing mechanism for ETSA Utilities - noting, of course, that the energy component of customers' bills may still be structured however retailers/generators deem most appropriate.

It is important to allow flexibility in the tariff solutions implemented by each jurisdiction – the load profile varies from state to state and it is likely that no one solution will work throughout the NEM.

We note also that capacity (demand) tariffs have been applied to large customers in South Australia for many years now. Large businesses tariffs on average consist of a 60% agreed maximum demand charge and a 40% consumption charge. We can leverage from the success and knowledge gained in implementing those tariffs. Capacity tariffs are a new strategy only with respect to smaller customers.

Finally, we note that although capacity tariffs require a 'smarter' meter than is currently the South Australian standard, the do not require the data intensity of time of use tariffs therefore enabling a thinner (or no[2]) telecommunications network to be implemented and use of smaller scale back-end systems. They therefore may represent a materially cheaper alternative to time of use tariffs.

[2] In principle, a capacity tariff does not require a communications enabled meter at all (standard manual reads can be utilised) however additional benefits may be obtained by implementing a 'thin' telecommunications network to the meter, and/or enabling time of use for other purposes (eg. to enable more innovative retail tariffs).

Retail pricing and incentives 8. Do retailers have the right incentives to pass through appropriate wholesale costs and network charges to consumers? 9. Do retailers have an incentive to minimise the costs of their customers' consumption?	No comment.
Cost-reflective tariffs 10. Would a tariff with a fixed, variable and network LRMC element as described in section 5.8 closely reflect the costs of supplying electricity? 11. What are the restrictions on retailers offering such a tariff?	See response to questions 5-7.
Potential for price signals to promote DSP 12. Can efficient levels of DSP be achieved without cost-reflective prices? What considerations are needed to achieve this?	ETSA Utilities concurs with the AEMC's notion that more cost reflective prices are a critical and essential enabler of successful DSP. However, more cost reflective prices in themselves will not necessarily deliver the 'firm' load reduction required by a distribution business to avoid/delay network augmentation. 'Firm' load reduction refers to the confidence that such load reduction will be available *every* time it is required. It is only when price signals are complemented with customer education and the take up of customer side technologies such as energy management systems, direct load control and energy storage that the dependability of DSP can be greatly improved. This can be seen from the response of the Industrial sector with customers generally having more sophisticated energy management capabilities. It is foreseeable that smaller customers will follow suit as the technologies that enable industrial customers to become more efficient, become cost effective for them (including, but not limited to, appropriate metering to facilitate more cost reflective prices).

Market conditions required for DSP	
Market conditions required for DSP 13. What other market conditions need to change to enable cost-reflective prices? Will the benefits from improving the cost reflectivity of price signals outweigh the costs of the actions to improve them? 14. Are changes to the current regulatory arrangements required to provide stronger incentives on NSPs and/or retailers to align price with cost?	The main stumbling block up to this point for cost reflective prices has been the cost of smarter metering required to implement these tariffs. However, if the cost of these devices reduces sufficiently and other market benefits can be accessed by the network business to justify the installation of smarter metering this will be less of an issue. When evaluating the effectiveness of incentives (regulatory or otherwise) upon a distribution business to pursue DM options in favour of augmentation, the following points need to be considered: • The rate of return on capital expenditure is established for projects having a low risk profile, equivalent to the 'tried and true' network augmentation alternative. DM alternatives invariably have a higher risk profile, associated with both their cost structure and the potential that they may not deliver sufficient demand reduction, or may not deliver that reduction in a timely manner or at the correct location. • In many instances DM projects will involve a direct trade-off, as the deferral of capital expenditure may require additional operating expenditure to be incurred. The regulatory incentives for capital and operating expenditure are not equivalent. • The distribution business does not currently have access to benefits accruing to other industry sectors such as transmission companies, generators and retailers. We note also that Part B of the DMIS does not cover tariff based initiatives. In South Australia the peak demand is driven primarily by air conditioning load during heatwaves (which may or may not occur in any given year) and uncertainty still exists regarding customers' initial and ongoing response to more cost reflective tariffs. Therefore any tariff based initiatives will put some DNSP revenue at risk. The DMIS aims to facilitate the development of economically efficient solutions to network constraints, which clearly should include tariff based solutions. As highlighted by the AEMC's Directions Paper, tariff based price signals are considered to be one of the keys to unlocking DSP. Although it is ETSA Utilities' intention to carefully consider the design of such a tariff if it should become applicable, there remains a clear disincentive to the implementation of more cost reflective pricing structures under the current regulatory arrangements.

Chapter 6 - Technology and system capability	
Supporting efficient investment decisions in DSP technology 15. Are there any practical additional mechanisms that could help alleviate the barriers to consumer investing in DSP technology? 16. What should be the role of intermediaries such as ESCOs in addressing the barriers to efficient consumer investment and what factors could be impeding the development of these parties?	In the absence of cost reflective pricing, there is little opportunity for consumers and/or ESCOs to extract value beyond those available through implementation of simple energy efficiency measures. For example, in the absence of a pricing incentive to reduce peak demand, customers or ESCO's have no reason to install peak lopping technologies such as energy storage (batteries). Other mechanisms are considered unnecessary if this pre-requisite is in place. However, time will be required for the market to develop solutions even in the presence of more cost reflective pricing. Prematurely depending on these solutions can lead to unnecessary risk to supply reliability. It is therefore important to allow the market time to develop before including the impact of DSP in load forecasting.
Commercial driven investment in DSP technology 17. What amendments to the metering arrangements in the NEM are required to facilitate commercial investment in metering technology which supports time sensitive tariffs?	ETSA Utilities considers that distributors are best placed to roll out and operate the smart metering infrastructure required to support DSP. We see no benefit in introducing new market participants to undertake such a role when distributors: • Have an existing relationship with customers in undertaking such a role; • Can leverage our existing systems, capabilities and experience to undertake such roll-outs; • Can gain significant value beyond DSP from smart meters, such devices being a critical component of the future 'smart grid'; and • Can provide open access to smart grid capabilities and data to other participants who wish to leverage from them to add further value (subject to appropriate data security protocols being in place).

	A distributor led roll-out thus minimises cost to customers whilst maximising value. This point is particularly pertinent when the potential network benefits of DSP are considered. For example, ETSA Utilities has undertaken analysis to consider the potential capex reductions, and reduce subsequent customer price increases, should DSP be able to reduce peak demand growth for existing customers to zero with no incremental opex or capex required to achieve this benefit (clearly an extremely aggressive scenario). Under such a scenario, capital expenditure over a 10 year period may be able to be reduced by about $0.75 billion, representing roughly 20% of the net capital expenditure of the business (the remainder representing expenditure related to new customer connections, asset replacement, information technology, property, fleet and so on). Considering the avoided return and depreciation on this investment, network charges could thus be reduced by some $75 million/annum, representing (based on current revenues) a reduction in price increases of less than 10% - even based on this extreme example. This being the case, it is not considered appropriate to dramatically change market structures and roles to achieve what is a modest, albeit prudent, benefit to consumers. It is important not to overestimate the benefit of DSP when considering it in comparison to traditional network solutions. As it currently stands it is only in cases where wider market benefit can be realised that DSP may be worthwhile to be pursued by a network business.

Consumer choice in metering capability 18. Are the current arrangements sufficient to facilitate a consumer's decision to install their own meter as a revenue meter? If not, what changes to the current arrangements are required? 19. Are any amendments to the arrangements required to encourage either the network businesses or retailers in invest in metering capability in order to support DSP options?	See response to question 17. The AER should be given the discretion to consider market wide benefits when evaluating the business case for DNSP roll out of smarter metering.
Optimising the value of technology and system capability 20. Are there aspects to the arrangements regarding the integration of DSP technologies into energy networks that requires further consideration under this review?	We note that as DSP technologies mature, and in particular, the cost of local generation and storage technologies reduce, it is likely that 'off-grid' energy solutions will become cost and performance competitive with 'on-grid' solutions. At such time, a competitive market for electricity 'distribution' will have been created and thus more light handed regulation will be warranted. Significant consideration should be given to the regulatory implications of such a future.

Chapter 7 - Supply chain interactions	
Distribution of DSP impacts across the supply chain 21. Can you provide a practical example of a DSP option which could deliver a net benefit to the market and also to the various parts of a supply chain. What are the reasons for such opportunities not being captured today?	Incentive mechanisms for DSP must enable a participant willing to pursue an initiative to extract benefits across the entire supply chain. The absence of such mechanisms will inappropriately stifle a range of initiatives having the potential to significantly benefit the community. The ENA has proposed alterations to incentive mechanisms to facilitate such benefits extraction. ETSA Utilities strongly supports these proposals. Drawing on its DM program of trials and further trials that are to be conducted in the near term, ETSA Utilities is of the view that residential battery storage systems could provide the bridge between local PV energy production and local residential peak load in South Australia. ETSA Utilities has conducted preliminary modelling of the cost benefit analysis for such devices on the basis of a distributor led roll out. Although the cost of storage, the uncertainty of take up rates and complexity of such a system needs to be carefully considered, from our initial analysis it is clear that market benefits across the supply chain will need to be considered for such a program to be viable. A smart metering roll-out is another obvious example. Finally, ETSA Utilities considers that current impediments to distributors bidding generation, stored energy or demand response into the NEM, where the primary purpose of such capabilities is for network support, should be removed. The ability to bid such capacity into the NEM (and potentially gain further revenue by storing energy during negative pool price periods) would increase the range of situations where such solutions may be more effective than traditional network infrastructure.

Co-ordination across the supply chain 22. How do the current market arrangements promote co-ordination across the supply chain to promote efficient DSP? What potential improvements should be considered? 23. Do you consider that there is inconsistency between how the wholesale and market sectors value DSP impacts? If so, is this a material problem to be addressed?	22. See response to question 21. We consider that the most critical factor is the ability for participants to access benefits across the entire supply chain. 23. No comment.
Effectiveness of the supply chain at capturing efficient DSP opportunities 24. Can market mechanisms be improved to facilitate supply chain interactions for efficient DSP? If so, what options should be considered by this review and what considerations should be taken into account?	No comment.
Role of cost reflective pricing 25. Would fully cost-reflective price signals enable the supply chain to act in a co-ordinated manner towards efficient DSP opportunities or would additional amendments be needed? 26. Would applying a network tariff scheme, similar to Orion's approach, be effective in the NEM?	ETSA Utilities is strongly supportive of greater cost reflectivity in pricing as discussed earlier. As indicated in the Orion example, we also consider that more cost reflective pricing of distribution services may encourage other market participants to alter their behaviour to reduce risk and/or maximise profit. Appropriate network tariffs depend upon the unique characteristics of the network, consumption profiles and climate. As discussed earlier, in SA, capacity based tariffs have proven extremely successful in managing demand for larger customers and are considered to have applicability for smaller customers as well. We stress again that flexibility needs to be given to distribution businesses to tailor tariffs to meet the specific cost drivers in their jurisdiction. No one solution will be applicable in all areas of the NEM.

Co-ordination across the supply chain 27. What are your views on possible approaches to achieving co-ordination across the market participants in the supply chain?	We consider that certain approaches to DSP, for example infrastructure based approaches such as direct load control, are most efficiently implemented by the monopoly service provider, the distributor. Such capabilities can then be provided to other market participants on an open access basis. Although there can be benefits in either the retailer, distributor or a third party establishing a DSP contract with a particular party, the distributor is best placed to effectively overlay the overall (temporal) requirement for a demand reduction against spatial load requirements to optimise the total reduction in customer load. No other market participant would have a capability to determine the most effective application of DSP both spatially and temporally.
Value of DSP benefits to the market 28. What should be the approach to quantify the value of DSP options?	Consistent with the position of the ENA, ETSA Utilities considers that to ensure consistency and some certainty, the DMIS should include a defined method or deemed value for the broader benefits of DSP activities: • that accrue outside the NSP boundary (ie to another network level and generation), • that are not directly assessable (eg NSP benefits to LV or MV feeder levels), and • that would accrue beyond the current planning horizon (where DSP effects are persistent). This approach should be endorsed for use in the building blocks for five yearly regulatory determinations, for assessment of alternatives under the RIT, and for determination of the incentive value under the in-period mechanism.

Methods to forecast the impacts of DSP option 29. Should standardised, common methods to forecast the impacts of DSP be developed? Is there a need for common approaches between network and operational planning?	'Firm' DSP is still in its infancy. As such any DM Innovation fund needs to allow for consumer responses not being as expected. To include the response due to, say, more cost reflective pricing in the short run would significantly increase the risk to supply reliability. ETSA Utilities supports the implementation of standardised forecasting methods for DSP once it is sufficiently mature.
Single actor option 30. If the required co-ordination across the supply chain cannot be achieved, should a market participant be assign with the responsibility to procure DSP options? If so, what issues need to be considered in the design of such an approach?	We consider that there could be significant benefits from a 'single actor' approach. As discussed in ETSA Utilities' covering letter, the limited benefits available from DSP would seem to make a complex regulatory approach with multiple actors unwieldy and expensive. A single actor, funded to deliver benefits to customers across the supply chain, would seem to be the simplest mechanism to extract benefit.

Chapter 8 - Wholesale and ancillary markets	
Load forecasting incorporating DSP 31. Should there be additional obligations on market participants to provide information to AEMO regarding DSP capability?	See response to question 29.
Becoming a registered participant for DSP 32. Are there issues relating to the costs and processes for becoming a registered participant in the NEM that require to be considered further in this review? If so, why?	No comment.
The role of aggregators in wholesale markets 33. What issues should be considered regarding the role of aggregators in the NEM? Should there be a new category of market participant for aggregators?	No comment.
Access to short term financial contract markets 34. How effective are current financial contracts markets at providing a hedge against price risk for DSP options?	No comment.
Remuneration for providing DSP in the wholesale market Given the discussion regarding the appropriate payment to DSP resources in the NEM, are there any other issues that should be considered by the Commission in regard to this matter? Are there any potential improvements to existing processes and other means to better facilitate DSP into the wholesale market that require consideration?	No comment.

Chapter 9 - Networks	
Profit incentives on network businesses 35. Do you consider that the current regulatory arrangements could prevent network businesses from pursuing efficient DSP projects which could contribute to achieving a more economically efficient demand/supply balance in the electricity market? 36. What options for reforming the current regulatory arrangements should be explored under the next stage of the review? 37. Do the current arrangements need to clarify distribution network businesses' involvement in distributed generation and if so, how?	There are currently significant disincentives to distributors to undertake efficient DSP rather than traditional network solutions. Key issues are that these solutions typically result in: • Higher risk, for example through potential triggering of STPIS or GSL penalties; and • Lower return, as the solutions will tend (necessarily) to reduce capex. These issues are described effectively in the AEMC's supplementary paper to this review. If distributors are to pursue DSP options more actively, appropriate mechanisms must be established to encourage: • At the macro level, initiatives to broadly reduce peak demand growth and thus reduce augmentation capex; • At the substation and feeder level, efficient non-network alternatives to augmentation; and • At the micro level, advice to customers to assist them in reducing the capacity of their individual connection points. Such mechanisms must ensure that distributors have access to benefits beyond those available through the construction of traditional network infrastructure. Such mechanisms must also offset and/or mitigate any potential revenue losses arising through the distributor's form of control and fairly compensate for the higher risk of such solutions. The ENA has proposed alterations to current incentive mechanisms to facilitate such benefits extraction. ETSA Utilities strongly supports the ENA's proposals.

	Once again, we note that the Demand Management Incentive Scheme (DMIS) in place for Queensland and South Australia is not currently an effective means of encouraging the development and implementation of DM. The DMIS should be amended to make it clear that even where the Part A cap has been, or will be, exceeded, projects may still be approved under Part A of the DMIS for the purposes of recovering foregone revenue in Part B of the DMIS. The loss of sales associated with DM projects is not a disincentive for a distribution business with a revenue cap, but will be for a distribution business operating under a price cap. Accordingly, Part B of the DMIS should be extended to cover all DM projects (including tariff initiatives) not already incorporated in the sales, demand and expenditure forecasts. Failing this, the barrier for the South Australian distribution business to implement such DSP projects, outside of the scope of Part A, is significantly higher than distribution businesses with a revenue cap (i.e. a Queensland distributor). ETSA Utilities is committed to complying with its jurisdictional requirements and will continue to observe the requirements of the ESCoSA Guideline 12 (and the imminent Regulatory Investment Test (RIT)), but in doing so it notes the effect of limiting the recognition of foregone sales revenue by the current DMIS Part B will reduce the likelihood that DM options will be financially viable, and therefore will not proceed. As mentioned in the response to question 21, ETSA Utilities also considers that the prohibition of it bidding generation or a demand response into the NEM should be removed.

Research into estimating potential demand reduction of non-contracted DSP 38. How should network businesses estimate the potential demand impacts associated with DSP? Should there be consistency in approach across the business and should arrangements provide guidance on how to do such estimation? 39. What should be the framework for recognising the impacts of DSP in the forecasting methodologies used during the regulatory revenue determination process?	See response to question 29.
Exemption from Service Standard Incentive Schemes 40. Is it appropriate for network businesses to be exempt from the service standard incentive scheme during the initial development phase of DSP projects? What factors need to be taken into consideration in designing such an exemption?	Such an exemption is considered appropriate to remove impediments and risk during the initial phases of such projects, but is not considered appropriate in the long term. Once approaches become standard industry practice, such exemptions would no longer be considered appropriate. Careful consideration would need to be given as to when a DSP methodology would become 'standard industry practice'. Consideration would need to be given to (for example) both the number of distributors having implemented such a methodology, and the period for which such a methodology had been in place.

Engagement with consumers 41. Should network businesses play aggregator role in informing consumers about the potential benefits from DSP and various DSP products? If so, how should they do so?	To engage a suitable sample size of volunteers for ETSA Utilities' DM program of trials we had to communicate with thousands of potential participants over a number of years through the provision of information packs, media releases, fielding customer queries and direct customer contact. A key learning from this exercise, which after five years is still ongoing in the North Adelaide trial area, is the public's lack of knowledge regarding all things electricity. Although retailers are traditionally tasked with facilitating the interaction between the consumer and the market, they do not necessarily have the in-house expertise and information required to communicate network-specific DSP benefits. Thus both retailers and network businesses will need to engage their customers (separately or in partnership) to effectively realise the benefits from DSP. Further to this the government could play a role in educating consumers in partnership with industry.

Chapter 10 – Retailers	
Settlement load profile for residential consumers with accumulation meters 42. Do you consider that settlement profiles which more accurately reflect actual consumption patterns improve incentives on retailers and/or consumers to offer/provide DSP?	No comment.
State based retail price regulations 43. What are the specific aspects of state based retail price regulations that restrict retailers from offering innovative tariffs or products? What amendments to the regulations could better enable retailers and other parties to facilitate DSP? 44. Should retail price regulation provide some certainty for retailers in their ability to recover any costs associated with facilitating DSP?	No comment.
Engagement with consumers 45. Should retailers play a greater role in informing consumers about the potential benefits from DSP and various DSP products? If so, how should they do so?	See response to question 42.

Chapter 11 - Distributed Generation	
DNSP Incentives schemes for DG 46. What incentives should be provided to DNSPs to ensure that they support DG projects? Is there merit in the proposal for DG proponents to pay DNSPs a fee-for-service to connect a DG installation? If so, how should this proposal be applied?	As DG becomes more prevalent in the distribution network it becomes paramount to correctly signal to customers the cost of DG connectivity. ETSA Utilities believes this adds to the case for customers in South Australia to be charged a capacity tariff for the network portion of their bill.
Metering and settlement arrangements for DG 47. What are the appropriate metering and settlement arrangements to facilitate the ability of consumers and DG projects to sell their demand response to any party? 48. Are amendments to the current market arrangements required to facilitate DSP contracts which enable the DSP provider to sell its services to any party? If so, what amendments are appropriate?	ETSA Utilities considers that current impediments to distributors bidding generation, stored energy or demand response into the NEM, where the primary purpose of such capabilities is for network support, should be removed.
Maximising the export value of DG to address peak demand 49. Should there be supplementary provisions to the arrangements governing feed in tariff payments to encourage such consumers who have micro generation units to maximise their export at times that enable deferment of network augmentation? If so, what are possible options to achieve this?	See response to question 47. Section 11 of AEMC's Directions Paper deals with distributed generation and its role in the NEM. The term distributed generation is used to cover roof top solar PVs and the use of batteries of electric vehicles to inject energy back into the grid, amongst other things. It does not specifically address residential energy storage systems or equivalent technologies. Consideration will need to be given to the design of the legacy feed in tariff currently in place if residential energy storage becomes widely used. The current design does not incentivise consumers to export at times of network constraint - in fact exactly the opposite is true and this will need to be reviewed.

Chapter 12 - Energy efficiency regulatory measures that integrate with or impact on the NEM	
Energy efficiency policies and measures that impact on, or integrate with, the NEM 50. What do you consider is the role for regulatory energy efficiency policies and measures in the context of facilitating uptake of cost effective DSP in the electricity market? 51. In your view, do consumers consider energy efficiency measures separately to DSP, or do they consider all actions as part of managing consumption and hence controlling electricity costs? 52. What are the elements for a best practice model or approach for energy efficiency policy to facilitate efficient investment in, and use of, DSP in the electricity market?	ETSA Utilities has found that although DM techniques may in fact reduce peak load, this can be at the expense of energy efficiency, leading to potential participants declining to participate. During ETSA Utilities' DM program of trials, a project conducted under the category of Voluntary Load Control (VLC) and Curtailable Load Control (CLC) for Large Customers was the installation of an Ice Storage System (ISS) to augment an existing Variable Refrigerant Volume (VRV) system. The trial achieved a reduction in peak demand of 34%. Overall though, the energy used was 11% higher due to the losses involved in the manufacturing and storing of ice. While there was a decrease in peak load, there was an overall increase in energy consumption. The client determined this to be a negative outcome and would not therefore introduce the system. This result, if replicated in other installations, may lead to customers declining to participate in DSP, particularly in the case of Government organisations which are seeking to reduce their energy consumption and carbon footprint. We consider that most residential consumers have little or no concept of the difference between improving energy efficiency and reducing peak demand. It is also true that some energy efficiency measures can reduce average demand, but have little impact on peak demand. By reducing the distribution network utilisation, such initiatives can increase the unit (per kWh) cost of distribution prices owing to the total cost of distributing energy remaining largely unchanged, but the number of units materially reducing. Policy makers must remain cognisant of these facts. Energy efficiency has little impact on distribution costs, and may <u>increase</u> per unit prices.