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Mr John Pierce
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Dear ~~Mr Pierce~~ John

AEMC Directions Paper: Power of Choice – giving consumers options in the way they use electricity

Ausgrid welcomes the opportunity to provide a submission on the *AEMC Directions Paper: Power of Choice – giving consumers options in the way they use electricity*. Since the announcement of the Power of Choice Review in March 2011, Ausgrid has been actively involved, both in terms of attending workshops and providing submissions to the Review.

In previous submissions, Ausgrid has outlined a proposed approach to creating incentives for demand side participation (DSP) in the National Electricity Market (NEM) with a particular focus on the role for distribution networks.

We believe that there is scope for increased amounts of cost effective DSP in the NEM and that there are no inherent barriers in the National Electricity Rules to prevent this occurring. The capacity exists but lies dormant within the existing regulatory framework and what is lacking is a well designed incentive to activate DSP.

Our attached submission sets out the elements which are required to activate short and long term benefits of DSP across the whole electricity supply chain.

If you have any queries or wish to discuss this matter in further detail please contact Keith Yates on (02) 9269 4171.

Yours sincerely

George Maltabarow

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AEMC Directions Paper: Power of Choice – giving consumers options in the way they use electricity

Ausgrid Submission

May 2012

1 Introduction

Ausgrid strongly agrees with the Commission that the level of demand side participation (DSP) in the Australian electricity market is clearly less than we consider would be efficient.

The electricity supply system is highly asset intensive. As such, the key driver of the cost of energy supply is the size of the system required to deliver it. Both the network and generation sectors are sized to meet the expected peak demand and therefore, in the long term, peak demand is the key determinant of cost. Ausgrid has estimated that each additional MW required to be delivered by the electricity system requires about $3.3m of assets to be installed, maintained and eventually replaced. In the current situation, the key role for the demand side is to manage peak demand.

Distribution network businesses are well positioned to facilitate an increased level of DSP. Indeed, distributors already have a significant role. There are current and proposed obligations in the National Electricity Rules (the Rules) that require distributors to: consider DSP options in every relevant investment decision; include market benefits in business cases; provide information to customers and DSP providers; and set prices as cost reflectively as they can.

However, these requirements are not matched by a regulatory framework that enables and incentivises distributors to be proactive in developing and implementing DSP options. The three key shortcomings we have identified are:

- a focus on short term benefits within the distribution business at the expense of the longer term and wider market benefits;
- a lack of certainty regarding the ability to fund DSP initiatives that would deliver longer term benefits across the supply chain; and
- a lack of a business incentive for distributors to develop more comprehensive DSP programs.

The shortcomings can be resolved primarily using the existing powers within the current Rules, representing the simplest, most readily achievable means of catalysing a rapid expansion in the level of DSP in the market.

The key elements of our proposal are listed below.

- Provision of clear guidelines and possibly deemed values to be used in business cases for DSP initiatives. These should reflect the long term benefits across the full supply chain that would accrue in addition to the clearly identifiable benefits within the distribution business. This would provide distributors sufficient certainty to develop substantial DSP programs that are proposed as part of the regulatory determination process.
- Development of an enhanced demand management incentive scheme that embodies a true business incentive for undertaking further DSP programs within regulatory periods. This would provide an incentive payment equal to a share of the benefits in the remainder of the supply chain.
- Continuation and expansion of the current Demand Management Innovation Allowance (DMIA) approach.
- Some minor adjustments to the Rules to equalise profit incentives between capital and operating expenses[1] and provide certainty of recovery of ongoing DSP expenses between regulatory periods.

[1] This element has also been advocated in submissions to the "Economic Regulation of Network Service Providers" Rule Change.

2 Peak Demand is a Key Driver of Cost

Over the long term, peak demand determines the overall size of the whole electricity supply chain and hence a large part of the cost of that supply.

Based on Ausgrid analysis, the unit cost of meeting additional peak demand is estimated at $3.3M/MW comprising:

- $1.5M/MW for Distribution[2]
- $0.8M/MW for Transmission[3]
- $1.0M/MW for peaking generation plants[4].

Developing a business case for DSP based on the full supply chain value requires an understanding of the benefits in each segment. Distributors are in the best place to undertake analysis of the localised benefits of DSP. In fact, it is arguable that they are the only entity with this capability in practical terms. The distribution element of the benefit mix is by far the most variable and complex to calculate because costs are specific to local areas, are generally in many small increments, and usually only apply during certain times.

In contrast, the value of DSP in other parts of the market is more readily calculated, more consistent over time and much less location dependent. These values could be calculated by an independent party (such as the Commission or the AER) as the investment cost that would be borne in the absence of DSP. At the generation and transmission level these factors are much more transparent and likely to occur in larger amounts (i.e. investment in a new open cycle gas turbine (OCGT) plant or an augmentation to a transmission line). This calculated value could be deemed for use in developing business cases for investment in DSP and as the basis for benefit sharing. The internal distributor benefits would not need to be externally determined as the network service provider would be able to internalise both the costs and that portion of the benefits.

3 Distributor's Role in Facilitating DSP

3.1 Outline of current obligations and what has resulted

The Rules allow the AER to develop incentive schemes to promote demand management. The AER's current Demand Management Incentive Scheme (DMIS) for NSW is comprised of the D-Factor scheme and the Demand Management Innovation Allowance (DMIA).

The D-Factor scheme allows a distributor to receive an incentive equal to the costs of demand management up to the value of the avoided cost in deferring a network project. The scheme also provides for foregone revenue resulting from lower volumes, and for the distributor to retain the value of the improvement in capital efficiency. However, the scheme is administratively complex (in terms of the calculation and review of cost efficiency and the distributor benefit components for each project) and does not allow for consideration of upstream benefits of DSP. As a result, it is limited in its scope to being focused on clearly identifiable network costs and benefits only.

[2] Based on the *Owen Inquiry Report, 2007* & *Preparation of energy market modelling data for the Energy White Paper*, ACIL Tasman, 2010 and *Possible Future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014*, AEMC, November 2011.

[3] Transmission augmentation costs are based on high-level analysis of information contained in the most recent AER determinations for Australian Transmission Network Providers[3] and assumptions relating to sustainable levels of network replacement based on a 50 year average asset life and generic allowances for Compliance & Non-System related investments.

[4] based on a high-level analysis of the most recent regulatory allowances for Australian Distribution Networks (including generic allowances for non-growth related programs) and a bottom-up analysis based on theoretical engineering network models and generic planning estimates for major capital items (zone substations, sub-transmission feeders, distribution substations/mains and low voltage mains).

It is notable that only one in ten non-network alternatives have been implemented under this scheme in the past three years and it has failed to incentivise the development of substantial levels of DSP or any broad based or long term approaches.

The DMIA provides funding for a distributor to invest in innovative demand management solutions to develop knowledge and experience with options which it may not undertake in the absence of the incentive. The scheme is currently capped at $5 million over the 2009-14 regulatory period. The scheme, while easy to apply, has been limited in its application due to the small amount of funding available.

Overall, the current DMIS, which encompasses both of these components, cannot be considered a genuine incentive scheme as it does not allow the distributor to receive a share of the overall benefits created by the demand management activity. At best, it is a cost pass-through mechanism for demand management activities.

In addition to DMIS, the Commission has put forward a Regulatory Investment Test – Distribution (RIT-D) similar to the RIT-T that applies in transmission. The RIT-D will explicitly require distributors to consider market benefits in the assessment of projects (including non-demand management and other network alternatives). The RIT-D would therefore operate in a similar manner to the current regulatory investment test, but would allow distributors to include market benefits in analysis of business cases for demand management.

The RIT-D is not without issue. This is because simply being able to consider the benefits does not enable proponents to access additional funds to cover costs of such projects within the regulatory period. The costs of the demand management project still must be paid for through the difference between the value of deferred network capital (return on and return of capital) included in the revenue allowance during the period, and the additional operating costs required (in addition to the allowance) to facilitate and operate the project. The business case for a network proposing a demand management option is therefore effectively the same under the RIT-D as it is under the current investment test – savings within the framework must be sufficient to pay for the project, otherwise it cannot proceed. At no point can a network access a separate funding stream to help pay for the project even though the benefits that may arise from the project may be spread through the market and more than outweigh the costs.

The inability of distributors to access a share of market benefits in financial terms means that investment in demand management projects will occur in fewer circumstances than might otherwise be the case (i.e. marginal cases will not be pursued). We would contend therefore that the inclusion of market benefits in the analysis of the business case does little to actually facilitate (i.e. fund) project implementation.

In addition to the regulatory test, the accompanying rule changes require the publication of exhaustive information about the network and forecast loading, and are potentially onerous and probably an ineffective requirement to market test demand side options. These prescriptive approaches have been shown to be ineffective in NSW and South Australia over several years in the absence of effective business incentives.

In summary, while the regulatory framework provides for cost recovery of network-initiated DSP options, there lacks a positive incentive for network businesses to actively pursue non-network alternatives. As a result, DSP activities that deliver a NEM-wide benefit, but not a current period network benefit (by deferring capital expenditure or maintaining reliability), are not proceeding because they are not considered profitable when considered only from the network perspective. There is an opportunity to change this within the current regulatory framework.

4 An Improved Incentive Framework for DSP

4.1 Components of appropriate DSP incentives in the NEM

In previous submissions Ausgrid has outlined a proposed approach to creating incentives for DSP in the NEM with particular focus on the role for distribution networks. We believe there is scope for increased amounts of cost effective DSP in the NEM and that there are no inherent barriers in the Rules to prevent this occurring. The capacity exists but lies dormant within the existing regulatory framework - what is missing are the incentives to activate DSP.

Below we set out the elements which are required to activate short and long term benefits of DSP across the whole electricity supply chain. The three elements required are:

1. **DSP within revenue building blocks at regulatory resets** - foreseeable short-term DSP as part of efficient capital and operating expenditure would be included within the regulatory period as well as longer-term demand management strategy expenditure primarily directed at efficient outcomes in future regulatory periods.

   Pricing initiatives directed at shifting demand are also part of the reset process. Therefore, the distributor business case for supporting short and long term DSP and the regulated revenues should reflect a sharing of the benefits to the whole value chain from a DSP activity.

2. **DSP opportunities identified within the regulatory period** – as projects are reviewed under the RIT-D, opportunities will emerge for DSP as the most efficient solution from a whole value chain viewpoint. To ensure efficient DSP is delivered in-line with the NEL objectives, a DMIS should allow networks a share of the transmission and generation benefits that a network DSP option delivers. DMIS market benefits would be predetermined deemed values for generation and transmission set to equal the long run marginal cost of augmentation. Note that adjusting for foregone revenues under a price cap is a separate independent issue to be addressed once the form of regulation is set.

3. **Support for innovation and development** – this is a continuation of the DMIA scheme at a viable level that would feed the RIT-D options development process and regulatory reset demand management strategy programs.

Importantly, incentives should be placed where they will prompt the appropriate action and deliver benefits. How benefits are delivered and the parties involved (retailers, distributed generators, aggregators and end use customers) should be left to competitive forces and markets as much as possible. For example, it is expected that appropriate incentives for DSP will increase the role for, and returns to, aggregators and distributed generation even if they are not directly incentivised or regulated.

4.2 DSP within revenue building blocks at regulatory resets

There is no barrier to including both short term and long terms DSP programs within the revenue allowance for distributors. This approach has been taken and has proved successful in Queensland with Energex and Ergon Energy. In making this allowance, the full-market value of options was included as well as long-term benefits not likely to be realised within the regulatory period.

The key elements required to ensure efficient programs are identified and included at the time of the reset are:

1. Appropriate values for transmission and generation DSP benefits.

2. Equalisation of the treatment of opex (often DSP) and capex (often traditional network) expenditures.

The value of benefits of DSP at resets should be consistent with within-period values discussed below.

4.3 DSP opportunities identified within the regulatory period - the RIT-D and DMIS

The newly proposed RIT-D process makes explicit and transparent the existing obligations to consider DSP when evaluating investment options. Moreover, the new requirement for a demand side engagement strategy will assist in increasing the profile of DSP options. However, we would contend that obligations alone (without incentives) have been unsuccessful at delivering an appropriate efficient level of DSP in the NEM.

Two explicit factors are missing:

- Recognition of whole of NEM value chain benefits in applying the RIT-D to ensure selection of the most efficient option. This only requires a clarification of what is covered by "consider" as part of the selection process.

- A DMIS incentive that will ensure the most efficient option for the NEM as a whole is also the preferred option for the network by ensuring a share of market benefits are available to the distributor.

4.3.1 An incentive mechanism for the DMIS

A DMIS mechanism already exists in NSW, which is a roll-over of the interim incentive developed by IPART in 2001, but this has had limited success because of its limited scope, its complicated calculation methodology and lagged application. However, this is a failing in design rather than in the underlying concept. For example, the S-factor incentive has proven to be highly successful and the principle of in-period incentives sound.

An incentive mechanism for networks is required to ensure an efficient level of DSP is implemented. This DSP incentive mechanism should go beyond cost recovery and embody a positive incentive payment that reflects a deemed value of the benefits of DSP activity to the wider electricity supply chain and customers, and a share of current and future benefits.

At present distributors could be disadvantaged by implementing efficient DSP due to differences both in capital and operating expenditure incentives and because the whole of market value of a DSP option is not accessible to distributors. Providing an incentive to distributors therefore requires a balancing of elements that deliver short and long term benefits to customers.

The DMIS incentive mechanism should recognise the difference in distributor incentives for capital and operating expenditure. At a minimum this should involve quarantining any efficient DSP operating expenditure from Efficiency Benefit Sharing Scheme (EBSS) calculations (as is currently the case), and preferably have a broader framework where operating and capital expenditure efficiency incentives are balanced.

A within regulatory period DSP incentive mechanism to ensure DSP options are chosen when they meet NEL objectives requires:

- sharing of benefits between regulatory periods – (like the EBSS method).
- valuing distribution, transmission and generation benefits based on the average long run marginal cost of augmentation.
- sharing of non-network benefits through incentives similar to these in the EBSS.
- appropriate treatment of capital and operating expenditure – (unless covered under a broader EBSS treatment).

Any new DSP incentive mechanism needs to be simple and transparent, elements which are missing in the current framework for DSP.

4.4 Support for Innovation and Development

The overall level of funding should reflect the size of the opportunity available for DSP across the NEM. In the long term the UK Innovation Funding Incentive (IFI) model (where a substantial pool of funding is available based on competitive bidding) may be an attractive option, but could be enhanced to allow distributors to capture of a portion of benefits of reducing costs in other parts of the supply chain. However, approved funding for DMIA within the distributor building block revenue is preferred in the short term for its greater simplicity and certainty.

4.5 Recommendations

Main recommendations

1. A new network DSP incentive mechanism is required to allow a share of the whole of market value of efficient DSP identified within a regulatory period to be retained by distributors.
2. A share of the whole of market value of efficient DSP identified at a regulatory reset period to be retained by distributors.

3. The value of DSP options to include default values for transmission and generation calculated based on average long run marginal cost of system augmentation.

4. Distributor benefit sharing of the whole of market value of DSP projects based on a 70% share of default values for transmission and generation.

5. Continue and expand the DMIA allowance for R&D and testing new approaches to DSP.

Supporting recommendations

6. Continue to quarantine DSP from EBSS calculations, either explicitly or as part of broader scheme changes.

7. Ensure equal treatment of DSP capital and operating expenditure, either explicitly or as part of broader scheme changes.

8. If the form of regulation requires, ensure recovery of revenue foregone for within period DSP projects (under a price cap recovery of foregone revenue is appropriate)

Include a share of long-term whole of market benefits of DSP strategies in regulated revenues at regulatory resets.

5 Responses to specific questions in the Directions Paper

1. What should be the arrangements for consumers (or third parties acting on their behalf) to access their energy data?

Consumers should have a right to access their own energy data (or to provide permission for a third party to have access). However this must be done in a manner that considers privacy, IP and operational impacts and costs that may be incurred in the provision of this data. Provisions may be required to prescribe the means of a consumer providing informed consent to third parties, standard data formats and potential cost recovery arrangements.

There should be no hindrance to any market participant that currently has legitimate access to the data also providing it to the consumer. However, ensuring access on reasonable terms for all consumers would probably mean that it should be a requirement for the responsible person.

Over the medium term, it is likely that only a limited number of customers will seek access to their meter data. However, with the introduction of more interval metering and more complex pricing it is likely that customers will seek access to their meter interval data so that they can independently reconcile their bills and manage their energy use.

One of the issues to be considered in any proposed data access solution is the means of limiting access for a customer to only historical interval data that relates to their consumption. For example, if a customer could access the historical consumption data directly from the meter there could be issues with data privacy because the customer could access the consumption data of individuals who previously occupied the site.

Ausgrid submits that a secure web based service could be offered by the responsible person's meter service provider as a means for customers to access their historical interval data. This could be a basic web based service which would then enable retailers or other service providers to develop more sophisticated solutions as part of their product offering.

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?

Customers faced with feedback about their energy use are better placed to make informed decisions about their energy consumption patterns and can more effectively weigh up the costs and benefits of consuming energy at certain times. However, provision of basic meter data could be established as an obligation on the MDP rather than through creation of new separate entity.

This would enable the market to bring forward providers of more advanced data in response to consumer demand, from existing market participants or third parties.

Access to energy data should be supported by energy literacy programs for all types of consumers. There may be a role for government or other regulatory bodies to act as providers of education resources if the market response is inadequate or insufficiently impartial.

3. Should amendments be made to the current NER clause 7.7 (a) to facilitate consumer access to consumption information? If so, how?

The Rules are fundamentally satisfactory in most respects. However, establishing an obligation on the MDP would require some Rule changes. It may also be useful to clarify that customers may access data without the necessary intervention of the financial responsible market participant, and that the customer may direct the MDP to provide the data direct to an authorised third party.

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 the vast majority of customers, information about how they can benefit from DSP options must be simple, relevant and actionable. To date, the level of customer education about the cost of consumption has been necessarily generalised.

Ausgrid, like many other market participants has provided educational information to customers regarding the running costs of appliances and the nature of electricity pricing. To date, the bulk of information provided to residential households is general and theoretical (historical consumption detail, facts, tips, hints). There are energy calculators available to customers to support them thinking through their energy consumption and appliance use. However, typically they rely on customers completing questionnaires and estimating appliance running times and as such, provide overall insights and guidance only and can be limited by a customer's perception of what occurs in their household rather than their actual behaviour and consumption.

Our best received information is often the simplest message. We recently developed some material with the simple premise that "if it makes something hot or cold, it probably uses a lot of energy" as a means of providing useful advice without information overload.

In many cases, the ideal way to provide information to customers about DSP options is as part of a DSP program with specific targets and response opportunities for consumers. This enables the messages to be targeted to those who can take action, geared to elicit the necessary action from the consumer, and simple enough to ensure good participation levels.

Technology can also play a central role in communicating price signals and consumption information to customers. Feedback technologies facilitated by technology such as interval meters or smart meters together with home area networks can communicate customer use energy via in-home displays or web-based interfaces.

Where customers have smart metering and as a result, potential access to real time data, then the opportunities to develop tools such as Customer Portals and in home displays exist. It is Ausgrid's view that these tools provide significant potential to assist customers improve their understanding of energy usage and increase their engagement in DSP. As part of the Smart Grid City Project, Ausgrid is trialing these arrangements to test customer engagement and behavioural response to receiving real time information, this project will also deliver important learnings on the operational and analytical requirements required to provide this option to customers in the longer term.

5. Should network charges vary by time of use?

Yes. Ausgrid has been at the forefront of time of use pricing in Australia since we commenced our meter replacement program in 2004. This program has resulted in around 360,000 or 22% small customers having interval meters and currently receiving time of use pricing at the network level.

It is anticipated that the number of small customers on time of use pricing at the network level will increase to around 500,000 by June 2014. It is also relevant to note that this successful deployment of time of use pricing has been achieved in an environment of unprecedented increases in underlying network charges.

Time based pricing has an important role to play in helping customers to appreciate that the cost of energy is not simple and fixed. Any level of improved cost reflectivity in the day-to-day tariff signals to customers that there may be options for them to reduce their bills by changing their consumption patterns. This has a positive effect in preparing them to be more receptive to DSP program offers when these are made, and reduces the cost of encouraging participation and response to DSP programs. Fully cost reflective pricing is unlikely to be achievable, but the ability to provide signals about the long term cost of consumption at peak times is a valuable component of improving the level of DSP in the market.

6. Should NSPs charge on a volume or capacity basis?

Few of the costs of providing customers with network services have any relationship to the volume transmitted through the network. The main drivers of overall network costs are the need to connect customers to the network, and the need to provide capacity sufficient to meet the coincident maximum demand at each point in the network.

Capacity charges are a significant and increasing component in charges for Ausgrid's larger customers, since the metering capability is already in place. These are invariably only applicable during the times when demand is likely to be coincident with the combined peaks. Where time of use capable metering is in place for smaller customers, we also apply time based charges with substantial differentials between peak and off peak prices. In 2011-12 the residential network peak price is more than ten times the off peak price.

As the time period of the peak price narrows, it further approximates a capacity price. Provided the applicable capacity time period is focused on the most likely time for local and regional coincident peak demands, there is a rationale for capacity pricing forming a part of the price formula.

7. What changes are needed to market conditions to facilitate more cost-reflective network pricing?

There seems to be an expectation that 'truly cost reflective' price approaches would enable integration of long term, short term and full value chain benefits at the point of consumption. We suggest that the complexity of time and geographically varying cost drivers for the electricity supply chain makes this not only impractical, but likely to be ineffective in driving significant change. However, this does not mean that, to the extent practical and effective, prices should not be as cost reflective as they can be.

More cost reflective energy pricing (based on interval consumption data) is an important underpinning factor. However, the ability to correctly reflect the highly dynamic geographic and time dependent nature of distribution costs in prices is very limited. Combined with the difficulty that consumers face in responding to very complex pricing signals, this means that other approaches are required, with better pricing as an important background element.

Under a Weighted Average Price Cap (WAPC) form of revenue control, a distributor has a strong incentive to apply prices that reflect as closely as possible its expected costs in order to minimise risk. This principle is the main argument in favour of this type of revenue control, and Ausgrid supports this approach. There has been some concern that WAPC might represent a disincentive to networks engaging in DSP. In NSW since 2004, this has been effectively solved through mechanisms to recover foregone revenue due to demand management initiatives. This has proven a better solution to balancing the requirement for cost reflective pricing and demand management neutrality than the application of revenue caps.

Aside from the application of WAPC control, the main barrier to more cost reflective pricing is the absence of appropriate metering technology. While the majority of meters are simple accumulation meters there is effectively no capacity to increase cost reflectivity of tariffs.

It has been noted that cost reflective network prices may not be passed on to customers, particularly if some customers value predictability and simplicity of prices more than the opportunity to take action to trim their costs. In this case, retailers would provide "insurance" services to ensure those customers were attracted to their products.

Even in the absence of prices being presented to customers, the ability to understand individual customer usage patterns will allow retailers to price individual customers at reflective levels overall, and provide the necessary data for the application of non-tariff DSP products and for the verification of usage changes.

With or without more cost reflective prices, better metering technology has merit in facilitating a greater role for DSP.

8. Do retailers have the right incentives to pass through appropriate wholesale costs and network charges to consumers?

Retailers who face time varying network prices have a choice to pass them through to customers or not. They face more highly variable prices from the wholesale market, but there is a natural hedge in that market from generators wishing to stabilise their revenue streams. No such natural hedge exists for network prices, so the retailer must either pass the price risk to their customers or charge a premium for accepting the risk themselves.

The best means of ensuring that retailers seek to pass on price signals (or take action to enable DSP themselves) is to have robust competition, ensuring the retailers who are most innovative will be able to out-compete other retailers.

The most important issue is to ensure that the retailers face network prices that are more cost reflective and costs that are attributable to individual customers.

9. Do retailers have an incentive to minimise the costs of their customers' consumption?

We believe retailers' main incentive is to secure and retain customers. The desire to work in customers' interest is a derived requirement that only exists where competition is strong. Retailers will naturally seek to minimise customer mobility (because acquisition is expensive and loyalty is valuable). Minimising customers' cost is one incentive to deter mobility.

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?

While this may be true, the description of network prices as including *"a network LRMC component which varies by location to signal the need for network investment"* sounds deceptively simple. In fact, constructing a price that accurately reflects the cost functions of the distribution network would be exceedingly difficult. The report itself suggests that *"The LRMC component could vary significantly between relatively small areas".* It could also vary considerably over time, leading to inconsistent price signals to customers over time, and the lumpy nature of network capital projects (in both cost and capacity added terms) will always throw up large discontinuities in truly cost reflective pricing. If, pragmatically, the network cost reflectivity is limited to the average long run marginal costs across a large number of customers, then the precision of the price signal is reduced.

Ausgrid has been investigating a range of more efficient tariff options over the past few years, including seasonal time of use pricing, dynamic peak time of use pricing and more recently capacity-based pricing. Ausgrid has implemented more cost reflective pricing for customers who consume more than 40 MWh per annum rather than an energy only based tariff.

While prices should be as cost reflective as they can reasonably be, we should not assume that pricing alone will be a panacea to encouraging substantially more DSP and solving the peak demand problem. There is a requirement to commit to the effort of developing simple product choice options and informing and recruiting customer engagement and participation. These activities are also required for the development of non-tariff DSP options.

Non-tariff DSP is likely to be as important in changing the level of DSP in the market as pricing, and we need to recognise the requirement to establish this capability alongside price based initiatives.

11. What are the restrictions on retailers offering such a tariff?

We are not aware of any restrictions on pricing flexibility for retailers in NSW. The capability of current billing systems may present a practical problem, but customer preference is potentially the strongest barrier. If customers are not interested in managing complex pricing, retailers will be rewarded with loyalty for managing the issue on customers' behalf. Political influence will reflect consumers' views. Complex cost reflective pricing may be a solution for some customers and perhaps more likely in the business sector. But many would remain uninvolved and other options are necessary. We discuss the role distributors could play in informing consumers about DSP in question 42.

12. Can efficient levels of DSP be achieved without cost-reflective prices? What considerations are needed to achieve this?

Ausgrid has been successful in implementing various DSP initiatives both in conjunction with cost reflective prices and without them. International experience suggests some of the largest DSP programs (for example the residential air conditioner cycling programs) have been implemented successfully with very simple price structures.

It should be noted that while a higher level of DSP is likely to result from more cost reflective pricing, significant DSP could also be developed without cost reflective pricing. Ultimately, the best approach is to have more cost reflective pricing in conjunction with non-tariff DSP initiatives. Together, a higher level of DSP will be achieved, or perhaps a similar level can be achieved at lower cost. Whether it is likely to reach a level that would be "efficient" is difficult to determine. However, given the currently very low level in the NEM, it seems likely that a combination of <u>more</u> cost reflective prices in conjunction with other measures is the wisest path.

Both of these changes are more likely to occur if actions are taken to enable and encourage sophisticated, energy focussed participants in the market to engage, develop and deliver 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?

The key limitation to enabling better cost reflectivity in pricing is metering technology. The second element is suitable billing and data management systems, which will require development time and investment. Assuming there is availability or clear knowledge of cost drivers, these would enable market participants to deliver more cost reflective prices in a technical sense. However, there will always be a need to supplement tariff mechanisms with additional financial and facilitation elements that enable customers to respond, and encourage consumer acceptance of more flexible pricing. Some of these elements may be effective in changing behaviour even in the absence of more cost reflective prices and could be commenced without changes to metering and billing systems.

14. Are changes to the current regulatory arrangements required to provide stronger incentives on NSPs and/or retailers to align price with cost?

As noted in our response to question 7, Ausgrid believes that more cost reflective pricing is likely to be incentivised under a WAPC form of revenue control.

15. Are there any practical additional mechanisms that could help alleviate the barriers to consumer investing in DSP technology?

The Directions Paper states "*We note that the investment costs for a number of systems which can enhance residential consumers' ability to save energy or shift their peak consumption are relatively minor We note that the investment costs for a number of systems which can enhance residential consumers' ability to save energy or shift their peak consumption are relatively minor*", and proposes this as evidence that consumers are not investing rationally in technology that would save them money. However, while the costs for some technologies such as those quoted may be low, the benefits can be similarly inconsequential.

To take the quoted example of the powerboard, modern appliance standby power is much lower than it once was. We estimate that in typical circumstances, such a device might save the consumer about $12 per year (and this at what is probably an overstated average cost).

However, to achieve this would probably require investment in an automatic powerboard (to ensure forgetfulness did not cancel out the saving), and these cost around $50. So the simple payback would be about 4 years, which is probably about the expected technology lifetime. So we are expecting a time poor consumer to spend time exploring and valuing a product that would leave them perhaps a dollar or two better of over several years. It is unlikely that a properly informed consumer would be happy with the result of that effort.

This is not to say we should not be seeking to facilitate consumers' investment in DSP products that are effective in reducing underlying costs. However, if we expect to engage residential consumers in this we need to focus on making the decision process simple and reliable, with very low transaction costs. Applying more cost reflective pricing and relying on individual consumer action may not be the best model for this situation.

We provide more detail on a distributor's role in alleviating barriers in question 42.

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?

ESCOs are intermediate service providers that can bridge the gap in financing, information and recruitment terms between the source of benefit (the market participants) and customers. ESCOs should arise when a profitable and reliable market opportunity exists. Our research suggests ESCO models have typically proliferated under utility sponsored rebate models, or under government programs (eg military, education and health sectors). There is very little evidence for vibrant ESCO sectors arising from market opportunities outside these environments.

If the benefits are large, and access to those benefits is difficult or complex, ESCOs are likely to emerge to assist consumers. Alternatively, ESCOs may be contracted by market participants as partners in realising the potential of DSP. However, it is important to note that the emergence of ESCOs is an outcome of having an effective means of capturing benefits from DSP. The focus should be on arrangements which enable the underlying benefit to be realised, and providing long term stability and predictability in the framework.

17. What amendments to the metering arrangements in the NEM are required to facilitate commercial investment in metering technology which supports time sensitive tariffs?

Commercial investment in metering technology will proceed where investors can secure sufficient benefits to outweigh the cost of deployment, and be sufficiently confident that their investments will not be undermined or replaced before the benefits are secured.

There are several possible models for the deployment of advanced metering and related technology, and for this reason market participants should not be precluded from deploying smart meters in the absence of Government mandates. We consider an essential element of the market structure put in place to support investment in metering technology needs to protect the benefits of the investment once it occurs. That is, once a market participant commits to a rollout of more advanced meters and installs such a meter, market arrangements need to protect the broader benefits of the technology/innovation provided by the investment.

This involves a consideration of metering standards and a nationally consistent minimum level of meter functionality as well as the role of the responsible person for the meter. It is very important that any such framework does not stifle innovation in more advanced options, products and services.

The Directions Paper notes "*that DNSPs argue that the rules currently discourage the distributor from making any investment in smart metering given that these meters are subject to metering contestability because of how they are read and possibly have a limited useful life.*"

This interpretation of the intent of the Rules is both problematic and counter to the reasoning in the Rules regarding meter requirements.

Customers with certain load characteristics are required to have type 4 metering, which also has electronic communication requirements. Installations of this type were determined to be contestable (on the basis presumably that the size of the load, the complexity and cost of the installation, and the relatively small number of customers affected made that a more economic approach)

Customers with smaller loads require only type 5 metering installations, which are permitted to be read using manual means. These lower cost, lower market impact installations were presumably assessed as being more efficiently provided under monopoly arrangements.

The perverse interpretation is that a customer whose load characteristics mean they require type 5 metering cannot be converted to electronic data collection - even though this may be less expensive - without becoming a type 4 metering installation and triggering the contestability rule. The result is that the consumers may face higher than necessary costs and distributors are strongly discouraged from investing in communicating meters for small customers.

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?

The question implies customers would own the revenue meter. This is unlikely to be satisfactory as the ongoing NEM obligations, including data and meter management would also need to be considered. Installation of smart revenue metering in the absence of supporting programs and price and service initiatives from networks and/or retailers would be of limited benefit. Customers are able to install meters in series with revenue meters if they wish to have greater opportunities to manage their own energy. Ausgrid suggests that there would be very low demand or benefit from such a change to market arrangements and the effort and administrative complexity would not be worthwhile.

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?

Refer to question 17 response.

20. Are there aspects to the arrangements regarding the integration of DSP technologies into energy networks that requires further consideration under this review?

No comment.

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?

The example quoted as figure 7.2 appears to be an analysis of a smart meter deployment, which is not an example of a DSP initiative. The benefits of smart meter deployments include a range of operational benefits such as meter reading and remote connection/disconnection, and the DSP benefits are difficult to determine (and may not exist) in the absence of clear plans for supporting programs.

Ausgrid has implemented a range of DSP initiatives that have had benefits at various levels of the supply chain. One simple example was the installation of network support generation at Nelson Bay. The primary benefit was to reduce peak demand on the 33kV feeders supplying the area, enabling an upgrade project to be deferred. In addition, a dispatch contract was signed with the local retailer that enabled them to also call the generator when wholesale prices were expected to be high. The resulting benefit of reduced wholesale purchase costs was shared between the retailer and the network. Because the benefits from wholesale dispatch were not able to be reliably predicted, these benefits were not considered in the business case, but the contract enabled the benefits to be captured. No benefits were attributed to the transmission network.

In contrast, in seeking to develop another demand management opportunity with a large customer, we contacted the customer's retailer and offered a similar arrangement in an attempt to capture the additional value available. The retailer responded that they were not interested as demand response options were not part of their wholesale risk management strategy.

Ausgrid has completed initial development of several possible peak demand reduction options. One of these is a trial program to develop dispatchable demand response with commercial sector customers. The program would reward customers for reducing demand in response to requests. The estimated costs of the program are $2.5m over 3 years to develop, and dispatch a demand response capacity of 15MVA. The ongoing cost of continuing the program beyond the initial period is estimated at $1.5m per year. The program would reliably reduce the peak demand on the local, regional, transmission and statewide level. Over the long term, this would lead to a reduction in capital in the distribution, transmission and generation sectors of about $3.3m per MW – almost $50 million in this case.

Even if we assume that, on average, it may take ten years for the benefits to be realised in all three sectors the net present value of the benefits over ten years would be three times the cost.

By delivering a consistent reduction in peak demand, prices in the wholesale market will be lower than they would have been, and these benefits will be passed on via retailer competition to customers. Further, the consistent reduction in peak demand will be reflected in transmission planning forecasts and reduce or defer the need for transmission augmentation – which will be passed to consumers through lower transmission revenue requirements and lower TUOS charges. Distribution costs will be lower by the difference between the avoided or deferred distribution capital and the cost of the program.

Even if the cost of the program were to be higher than the distribution benefits (which would mean it would not proceed under the current framework), the benefits flowing from the other sectors would mean customers were better off.

22. How do the current market arrangements promote co-ordination across the supply chain to promote efficient DSP? What potential improvements should be considered?

As we have outlined there appears to be little practical coordination on DSP across the supply chain and, although this may be technically possible, the barriers from transaction costs, unfamiliarity and lack of alignment of interest make it practically impossible. While there is merit in continuing to seek and facilitate opportunities for cooperative DSP, the improvements we have suggested in section 4 would enable an increased level of DSP that responds to the full market value.

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?

There is a potential issue with the nature of price variation in the wholesale market compared to the long term benefits of reduced peak demand in the generation sector. The very high price events (VOLL or near VOLL) tend to be related to unexpected events such as transmission outages or load conditions being substantially different to expected. This randomness in price "spikes" is a key reason correlation between demand and price is not as high as one would expect. However, at the next level of prices – those that are substantially higher than the time weighted average, but not extreme – there is much more substantial correlation. It might be argued that a new entrant peaking generator is more likely to react to the likely existence of prices in the market at this level than at extreme levels to underwrite the revenue required to commit new capital.

DSP operated solely to pursue the arbitrage value of the rare but very high peak prices may not contribute in any substantive way to the avoidance of the need for the next peaking generator. However, DSP operated to depress the peak demand in the market over the long term would not only act to reduce the need for new generating investment, but have a much higher likelihood of being effective at the transmission level and even in the higher levels of the distribution network.

If DSP is to be designed and operated to deliver long term value through reduction in the size of the energy supply system, it may need to respond to demand, rather than short term price in the wholesale market.

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?

To improve the likelihood that distributors will implement more DSP that is beneficial across the full supply chain, we propose the improvements we have suggested in section 4. The key principles are that distributors be able to fund DSP programs as standard control services on the basis that they deliver net benefits across the supply chain; that they be incentivised to do so by being able to earn returns from DSP alternatives to at least the same extent they would from traditional network investments; and that they have sufficient certainty over the consistency of regulatory decision making to be able to commit.

Other approaches to facilitating supply chain value integration that appear to hold promise should be pursued in parallel.

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?

Ausgrid contests the assumption that the achievable level of cost reflectivity in prices will enable customers or their agents to integrate the value individually and make the appropriate multi-dimensional decisions. Lack of perfect cost reflectivity and lack of interest from significant numbers of customers in complex interactions means we will always need other mechanisms.

26. Would applying a network tariff scheme, similar to Orion's approach, be effective in the NEM?

Orion's pricing model applies a single price signal for all customers at all locations in their network. This suggests that there is no reflection of locational variation through the distribution network and that the primary purpose is to limit system wide coincident demand. It is notable that transmission costs represent a third of Orion's cost structure, which may encourage such a focus.

This is an example of the approach to peak demand management exhibited by many utility businesses around the world, where the dominant cost focus in on managing the cost of peaking generation, or transmission network investment. Ausgrid has found very few examples of approaches focused on distribution network costs. Ultimately the Orion approach, while interesting, appears to be insufficiently discriminate to be considered "truly cost reflective".

Nonetheless, this does demonstrate the power of more cost reflective pricing to stimulate and support a range of approaches to DSP. Ausgrid believes the ability to measure the usage profiles of individual customers remains fundamental to the application of more cost reflective prices. This is preferable to adjustments to the net system load profile settlements methods.

27. What are your views on possible approaches to achieving co-ordination across the market participants in the supply chain?

In terms of possible approaches to achieving co-ordination, Ausgrid submits that our recommendations outlined in section 4 would be a prudent approach, and should be a component of any revised regulatory framework.

28. What should be the approach to quantify the value of DSP options?

In developing our position on increasing the level of DSP in the market, and in particular enabling distributors to increase their contribution, Ausgrid has considered a range of approaches to estimating the benefits from reduced peak demand,

The marginal cost of supply has been estimated by various parties using a variety of methods. The cost of adding peaking plants (usually considered as open cycle gas turbines) is a well accepted proxy for the marginal cost of generation, and we have accepted that a median estimate is about $1m per MW.

The long term cost of transmission varies from state to state due to geographic differences and the use of different definitions and network architectures. Nonetheless, the range of estimates is relatively narrow and centred at about $0.8 million per MW.

Calculating average values for distribution is more problematic, but various methods ranging from the purely observational to bottom up modelling reveal remarkably similar values. For Ausgrid's circumstances, we estimate the long term value at about $1.5m per MW. One of the difficulties arises from the highly "distributed" nature of distribution assets, which makes it challenging to define what is meant by a MW of peak demand. Since the cost of distribution responds to the demand imposed on each element, and that demand has different timing, growth and even seasonal factors, it is not adequate to consider a MW measured at the global, or transmission connection point a suitable measure.

For this reason, we have proposed that it is likely that the Commission could develop standard national estimates, or perhaps state based values at worst, of the long term benefit of peak demand reductions in the transmission and generation sectors. Ausgrid intends to undertake further analysis of this area and will provide updates to the Commission as new information is developed. However, it is important to note that the costs in the retail and market management sectors are unrelated to peak demand and are therefore at best a minor contributor to the marginal cost of demand in the value chain and need not be included.

Ausgrid is encouraged that the AER approved in May 2010 substantial funding for broad-based demand management programs in the Queensland electricity regulatory determinations based on economic analysis that included benefits in the whole energy supply chain. This approach was made under the existing Rules and the allowance relating to demand management spending was much higher than anything that had previously been incorporated in a distributor revenue determination. Importantly, Energex proposed a value of DSP relating to longer-term and upstream market benefits as a basis for the approval of their program and this was accepted by the AER. By permitting expenditure on the basis of these wider benefits, the AER implicitly allowed Energex to secure a portion of those benefits.

While this demonstrates the possibilities under the existing Rules, there remains a lack of certainty about how such an approach would be treated at the next regulatory determination, or in any other state. An option may be for an independent periodical review to establish deemed values and methodologies for the inclusion of upstream and long term benefits in DSP business cases. This would streamline assessment of demand management options for networks and regulators alike and not only lead to more demand management projects being undertaken, would allow businesses to plan demand management projects with confidence that can be included in its regulatory proposal.

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?

Forecasting impacts is an essential part of the business case for a DSP option. Given that the options are not known at the time of the forecast, it is difficult to see how it would be possible to standardise the means of forecasting their impact. Beyond a requirement for a forecast and review of actual impacts, it seems unlikely to be helpful to have standard forecasting methods that are unproven. AEMO will need to continue to work with market participants in this area.

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 would submit that a form of this approach is effectively in place now to some extent with the obligations on distributors under the Rules. This is in no way an exclusive arrangement, and if "single actor" is intended to imply the carrying out of DSP and engagement with consumers would be done by a single party we would not agree. Instead we see the current obligations on distributors to take full market benefits into account in investment decisions require us to seek to integrate the whole market value, and explore all the implementation options available to seek the most effective and efficient means. Where the best approach involves retailers, third parties or contracted delivery, this is what we would expect to utilise.

The problem with the current arrangement is that the obligation is not matched by certainty of cost recovery and business incentive to ensure that it becomes effective. While other approaches are possible and certainly should not be excluded, the approach we have proposed in section 4 is the most readily available and simplest option that has a good chance of success.

31. Should there be additional obligations on market participants to provide information to AEMO regarding DSP capability?

This is a complex area that requires further work between AEMO and market participants. Distributors would be happy to provide their expectations to AEMO provided the data requirements were not onerous. Beyond that, AEMO will need to observe market behavior. To the extent DSP is undertaken under competitive contracts, or by consumers on their own behalf, there is little opportunity for AEMO to have better information about likely outcomes.

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.

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?

Any new category of market participant should be subject to Rule consultation. Moreover, registration as a participant should come with appropriate prudential requirements.

34. How effective are current financial contracts markets at providing a hedge against price risk for DSP options?

No comment.

35. 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

36. 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?

In relation to bringing forward an economically efficient level of peak demand side participation, Ausgrid considers a barrier is the disaggregated nature of the energy supply chain, which limits the ability of individual businesses within the national energy market to integrate both the costs and benefits of peak demand management initiatives[5].

We submit that there are a series of demand management actions which are available to reduce the growth in peak demand. These actions include more efficent pricing, curtailable load, energy storage, alterative sources of energy and energy efficiency measures. If implemented, these options are likely to dampen the growth of peak demand and therefore tend to reduce future costs. However, current systems and incentives for promoting peak demand management and demand side participation are not leading to significant implementation of peak demand management in the NEM. In recent submissions to the Commission[6], we also explained that the challenges and barriers to implementing peak demand.

There are recognised difficulties in the current regulatory framework in terms of incentives for DSP compared to other types of investment (although there are few actual barriers in the Rules themselves). Regulatory reform should not be driven primarily by considerations for DSP, but by fundamentals of good incentive regulation. Ausgrid maintains that a peak demand management incentive mechanism should be integral to electricity market design. We propose that a new, explicit, long-term incentive for distributors to pursue demand management would be desirable and that such an incentive should allow significant economic value to be released in the form of lower future costs for customers. Only an incentive will drive change.

Distributors are already regulated and manage the most localised and complicated element of the demand management value chain (between the transmission system and the consumer's premises). A mechanism that allows distributors (as the DSP sponsor) to share the benefits from the longer-term and full supply chain value of their peak demand management initiatives would provide commercial incentives for DSP. This would allow them to engage with customers, other market players and third parties to deliver peak demand reductions that respond efficiently to market requirements. We believe this would be an efficient option for dealing with the complexity of capturing peak demand management value and lead to significantly increase levels of DSP.

An example where incentives are not capturing the true intent is the NSW D-factor scheme. This scheme is too focused on short term, specific project deferral. It has proven to be too narrowly defined and administratively complex, and ultimately resulting in a disincentive as Ausgrid is now receiving a negative incentive under the D-factor. In addition, it does not currently allow for consideration of upstream benefits of DSP and as a result, is limited in its scope to being focused on network costs and benefits only.

We submit that a mechanism that provides for a similar deemed value approach to be applied within regulatory periods is required. Under this arrangement, the regulator would determine a deemed value for the non-distributor benefits of DSP and a fixed share of those benefits would be claimable by the distributor for verified DSP projects undertaken. This new D-factor mechanism would be paid under similar recovery provisions as the current approach.

[5] Ausgrid's submission on AEMC Power of Choice (DSP3) Review pages 5, 6 and 7.

[6] Ausgrid's submission on AEMC Power of Choice (DSP3) Review, 8 November 2011 and the AEMC Review of Strategic Priorities for Energy Market Development, May 2011

There would be no need for assessment of avoided distribution costs or review of efficiency of project costs, as these would no longer form part of the mechanism. Instead, the incentive component (currently equal to project implementation costs capped by the avoided distribution costs) would be determined according to the deemed values for non-distributor benefits.

The result would be that where there was an internal benefit to the distributor, this would be added to the share of external benefits and the greater total benefit would make more DSP cost effective. It would also permit the distributor to justify the implementation of longer term and more broadly based DSP where the main benefit came from the deemed component and internal benefits were longer term or difficult to quantify.

Again, this would facilitate a greater amount of demand management projects to take place, and increase the level of DSP in the market – noting again, that once a capability has been established, it can be called upon multiple times for relatively small incremental cost.

37. What options for reforming the current regulatory arrangements should be explored under the next stage of the review?

As outlined in section 4, Ausgrid submits that only minor changes to the Rules and the AER's practices and guidelines are required to unlock substantial benefits. We are willing to assist the Commission in bringing these reforms forward. To that end, we will actively participate in the next stage of the review which will examine opportunities to facilitate efficient DSP in the electricity market in the longer term. We understand that this next stage will focus on distributor network profit incentives and their ability to manage risks of DSP projects as well as supply chain interaction, including incentives across industry participants and how the supply chain captures DSP.

38. Do the current arrangements need to clarify distribution network businesses' involvement in distributed generation and if so, how?

Distributors are obliged to connect on fair commercial terms and are subject to legitimate technical requirements. Distributors may develop and own distributed generation as network support (but cannot set market prices) and distributed generation should be registered so energy can be traded (depending on size).

39. 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?

The current and proposed Rules and obligations for consideration of demand management alternatives by distributors are sufficient. It is arguable that they are more onerous than is cost effective, but the missing element is incentive. Provided it is in the interests of distributors to undertake demand side options in preference to investing in additional networks, the distributors will develop and seek out the necessary expertise to do it well and efficiently.

Incentives are vastly preferable to prescription and regulation. Prescriptive approaches without incentive have been shown many times over to be ineffective, wasteful and ultimately frustrating for all concerned.

The evaluation of the impacts of DSP in the range of situations in which it might be utilised within a distribution network is complex. The consideration at the heart of the matter is the management and maintenance of supply standards for the benefit of customers, and this is not a one size fits all issue. Ausgrid would not support codification of DSP impacts. However, cooperation among network businesses currently exists and will expand if appropriate incentives are in place.

40. What should be the framework for recognising the impacts of DSP in the forecasting methodologies used during the regulatory revenue determination process?

The current regulatory framework and successive determinations have developed load forecasting to a very detailed level. There is already substantial exchange of information between network businesses and consultants working in the area to improve the quality of load forecasting in many ways. Ausgrid expects the development of methods in this area to continue to change and develop, and the appropriate recognition of DSP actions is just one element of the process. Ausgrid does not see a necessity for a framework for the recognition of DSP in forecasts.

41. 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?

Ausgrid has not formed a strong view on this issue as we are yet to be exposed to a STPIS scheme. However, our initial response is not to mix incentives and to not seek exemption. This is because consideration of potential impacts on reliability and consequent risk of financial penalties must be considered when formulating demand management alternatives to supply side options. There are many approaches to risk management that might be employed, but exemption may have unintended consequences.

42. Should network businesses play a greater role in informing consumers about the potential benefits from DSP and various DSP products? If so, how should they do so?

Distributors are well placed to play a greater role in informing customers about DSP and delivering DSP products. A broad skill set is required to successfully deliver DSP products and programs, these skills include technical, operation, and pricing capabilities all of which are possessed by distributors. In addition, distributors such as Ausgrid have been participating in the DSP space for many years and have significant experience already.

It should also be noted that DSP outcomes are critical to distributor businesses to support management of their network assets, particularly in the management of the issue of rising peak demand in an overall market where total consumption is reducing. This issue has a fundamental impact on distributor businesses and as a result, they have strong drivers to support and encourage DSP activities.

From a market participant perspective, it is Ausgrid's view that distributors are in a strong position to run DSP information programs and deliver DSP products directly to customers over the longer term. Network businesses are responsible for delivering electricity and have an obligation to inform customers on how best to use the product they deliver. Because they have no competitive role in the market, this information is more likely to be seen as impartial. In this way, DSP initiatives are not directly linked with the potentially shorter term relationships that may exist between a customer and their retailer (which in a competitive market may change as opposed to an ongoing engagement with the distributor that delivers infrastructure to the customers premise).

However, there has historically been difficulty in including costs for such a role in building block expenditure because it does not respond to a specifically identified regulatory requirement. We would contend that such behaviour would be typical of a similar business operating in a competitive market and responding to customers reasonable expectations of corporate responsibility for their product. Some form of instruction to the AER that required them to recognise a role for distributors in supporting customers' knowledge and ability to manage their energy usage would be sufficient.

The Directions Paper states "*To date DNSPs have had limited need for such engagement with consumers but are starting to recognise the need to have effective community and service provider engagement models for DSP*". Ausgrid suggests this statement is inaccurate and fails to recognise that some distributors have been engaging successfully and without significant concerns or interaction with other players for a long time.

It goes on to say that *"Retailers take the opposite view with AGL arguing that monopoly businesses should have no contact with consumers."* This is not supported by the NECF triangular approach nor by normal commercial practice. The suggestion that retailers should have an exclusive right to interact with consumers of energy runs counter to the current reality and any appreciation of the practice on any other area of commercial endeavour. It is unclear how retailers would seek to change the current legal framework to prevent others from contact with energy customers, and particularly those with regulatory obligations and contractual relationships for provision of connection services.

43. Do you consider that settlement profiles which more accurately reflect actual consumption patterns improve incentives on retailers and/or consumers to offer/provide DSP?

A steady move to interval metering would be preferable. As the residual accumulation meter population declines, the net system load profile would become less relevant.

44. 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?

No Comment.

45. Should retail price regulation provide some certainty for retailers in their ability to recover any costs associated with facilitating DSP?

No comment.

46. 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?

In a competitive market, retailers should be incentivised to inform customers about their energy use. Active competition will determine whether this is a service that customers value.

47. 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?

We note the Commission states that the term 'distributed generation' and the term 'embedded generation' are equivalent terms for the purposes of this review. Ausgrid considers that distributed generation is defined as generation that is located within the distribution network, but not located on the customer side of the meter. Embedded generation, which is generally smaller in installed capacity, is located on the customer side of the meter.

We agree that over the coming decades distribution networks will be required to integrate a broader range of power generation and management technologies than it was originally designed for (e.g. the wider deployment of intermittent and distributed generation). Historically, a distribution network has been uni-directional; that is, it transported energy from the traditional large generation sources to the customers. This uni-directional concept has been the basis of traditional planning, design, and investment for decades, and has had a significant impact on the standards specified in the existing NSW Design, Reliability and Performance (DRP) licence conditions.

The emergence of increasing numbers of power generation and management technology connections deeper within the distribution network, that can alternate between requiring load from the distribution network and exporting load into the distribution network at diverse points within the network, complicates power quality, load-flows and capacity planning. Moreover, where the output of the power generation is large enough to significantly influence the normal load-flows (in some cases even reverse them), there are additional technical issues that need to be addressed, particularly with respect to protection and voltage regulation.

Due to the requirement of distributors to maintain required levels of network performance for all connections, additional costs can be borne by distributors to accommodate the time variant output of the generators. The issues presented by increasing volumes of power generation are currently being managed on a case-by-case basis to maintain the integrity of the power system. However, as the market develops it might become appropriate to provide a distributor with incentives to connect such installations.

48. 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?

No comment.

49. 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?

No comment.

50. 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?

Cost reflective pricing would reward owners of micro generation who reduced their maximum demand. Any effective framework that incentivises cost effective DSP would be similarly effective at unlocking network support payments for distributed generation owners. Feed in tariffs as implemented in Australia have proven a blunt instrument for the delivery of cross subsidies to particular customers and technologies. Better options exist for managing and promoting cost effective distributed generation.

51. 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?

Energy efficiency targets different outcomes to peak demand reduction, and while it may be effective at reducing consumers' energy bills, it can lead to higher unit prices and only occasionally contributes to peak demand reductions.

Energy efficiency policies are best applied by governments in pursuit of broad energy objectives like the minimisation of greenhouse emissions or improve energy intensity of the economy. Where a peak demand reduction strategy also contributes to energy efficiency, the application of government incentive and policies should provide a natural cost advantage over measures that do not have those benefits.

52. 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?

No comment.

53. 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?

No comment.