Joint submission to AEMC

Distribution Network Pricing Arrangements Rule 2014

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Mr Zaeen Khan
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Dear Mr Khan

Submission to Rule Change Consultation Paper on Distribution Pricing Rules (reference ERC0161)

Ellipson and TEC are pleased to present a joint submission to this rule change process.

Ellipson is a consulting business that provides services for end use energy consumers in the area of pricing and procurement. The company has a significant experience in addressing customer issues that relate to electricity supply costs including the regulation of electricity network prices. Ellipson is currently undertaking a research project funded by the Consumer Advocacy Panel (CAP) on the implications for small customers of more cost reflective distribution network tariffs.

TEC has been involved in National Electricity Market (NEM) advocacy for eight years, arguing above all for greater utilisation of demand side participation — energy conservation and efficiency, demand management and decentralised generation — to meet Australia's electricity needs. By reforming the NEM we are working to contribute to climate change mitigation and improve other environmental outcomes of Australia's energy sector, while also constraining retail prices and improving the economic efficiency of the NEM — all in the long term interest of consumers, pursuant to the National Electricity Objective (NEO).

TEC is supporting Ellipson's CAP-funded research project, and is currently involved in two other CAP-funded projects related to network tariffs:

1. A rule change request (submitted on 29 November 2013) for the reform of Clause 6.6.3 of the NER, supported by a report on demand management by the Institute for Sustainable Futures, which proposes expanding the current DMEGCIS to incentivise distribution networks to engage in tariff- as well as activity-based demand management activities.
2. An Advocacy Panel funded project, also conducted by the Institute for Sustainable Futures, on the introduction of virtual net metering (VNM) into the NEM. This may impact on the current rule change process, since VNM revolves around the idea of lower network charges for local generaiton and consumption. Alternately, it may result in a further rule change request in the second quarter of 2014.

Ellipson is the lead author of this submission. Please note that responses have not been provided to all the questions in the consultation paper. This is because the questions are either out of scope of the research project, or the results of the research are not yet complete (as of 19 December).

We would welcome the opportunity for further input into this rule change process.

Yours sincerely,

WRNixey

Bill Nixey, Director, Ellipson

Jeff Angel, Executive Director, TEC

Distribution Network Pricing Arrangements Rule change consultation paper

This rule change process has two broad components: the timing of network tariff proposals, and the reform of tariffs to be more cost-reflective. This submission focuses mainly on the second component, since this is within the scope of Ellipson's research project and TEC's work on VNM.

Nevertheless, we support the concerns of IPART and SCER regarding the timing issue, and strongly agree that networks and the AER should consult with energy consumer groups annually on the development of the structure of their tariffs and the level of prices.

In particular, we support the introduction of an annual or 5 yearly network Pricing Structures Statement (PSS), for the reasons identified by SCER, including tariff structures, charging elements and costs, but not necessarily tariff pricing levels. We consider that PSSs should be binding, with networks required to go through another consultation process if they wish to amend their tariff pricing principles within a 5 year determination period. We consider that networks should consult with stakeholders either prior to submitting their regulatory proposal, or during the AER's assessment thereof. We also support PIAC's suggestion "that DNSPs be required to show the AER how they considered feedback from residential consumers in their annual network pricing proposals" (p 29).

Question 1 What other considerations should be included in the assessment framework?

The consultation paper identifies efficient pricing, stakeholder engagement, predictability, allocation of risks and regulatory burden as part of the assessment framework. Another important component of the assessment framework should be practical considerations. It is important that the proposed changes to the Distribution Pricing Rules are clear and can be implemented by participants. As the AEMC's Power of Choice review states "Network and retail prices will inevitably reflect a balance between the need for efficient signalling of costs and more practical considerations".

Not all of the recommendations from the Power of Choice review were adopted by SCER in its proposed variations to the Distribution Pricing Rules. This wasn't acknowledged in the SCER rule change or in the current AEMC consultation paper. Three important areas not carried over from the Power of Choice to the SCER rule change include:

1. *Allocation of the revenue residual*. The Power of Choice review recommended that clause 6.18.5(c) be amended so that any residual revenue be allocated on a postage stamp basis and not with "minimum distortion to efficient patterns of consumption". This change was considered important in Power of Choice as it would prevent revenue being allocated to small customer tariffs and where the consumer is not able to respond to new price signals.
2. Small customers would not receive the efficient and flexible cost reflective prices unless they elected to. This *opt in approach* provided a safety net for consumers who are not "energy literate" or are unable to respond to the prices. However the SCER rule changes require that all distribution tariffs and charging components be based on long run marginal cost.
3. The Power of Choice review stated that *consumer engagement* is crucial to the success of any introduction of efficient, flexible cost reflective price structures. "Eliciting consumer engagement is a critical aspect of realizing the benefits of flexible pricing and this will depend on how the transition is managed." It also stated that to ensure this engagement a "comprehensive education campaign to be employed". The SCER rule change does not acknowledge how these recommendations have been taken into account in its proposed changes.

Equity should also be a critical part of the assessment process, for two reasons:

1. The move to more cost reflective pricing may have adverse consequences for classes of consumers which have limited capacity to respond to time of use or critical peak pricing tariffs.

2. The introduction of LRMC may result in locational network tariffs, based on network capacity constraints. This could produce inequitable outcomes — for instance, with neighbours potentially paying widely varying prices through no fault of their own, but because they are served by different substations, one of which may require upgrading. The implications for different groups of consumers should be an important consideration.

Question 2 Does figure 6.1 reflect the key components of how network tariff structures and pricing levels determined by DNSPs?

Figure 6.1 does reflect the key components of how network tariff structures and pricing levels are determined by DNSPs. However this explanation can be simplified by breaking up the annual price setting into two parts;

1. Allocating annual network costs to tariffs and charging parameters.
2. Allocating the annual components of 5 yearly building block revenues to tariffs and charging parameters.

In price setting a priority is given by distributors to the allocation of building block revenue to the tariffs and charging parameters. Therefore network tariffs do not reflect actual underlying costs but are in fact place markers for the recovery of regulated revenue. It is the relative proportions of revenue recovery across tariffs and charging parameters and how they change over time that is relevant in any move toward cost reflectivity. As the POC review states "we do not mean prices that are perfectly cost reflective from a theoretical standpoint; rather we mean prices that will provide a more efficient signal to consumers for valuing consumption and energy services than those which exist currently".

Question 5 Should DNSPs be able to vary their network tariff structures during the regulatory period? Why or why not?

Regulatory periods span five years and over such an extended period of time it is possible that networks will need to be able to respond to market changes with new price structures. These changes could result from technological developments or the introduction of government policies. One example in the current regulatory period for NSW was the state government's Solar Bonus Scheme. In late 2009 this scheme introduced a 60 cent feed-in tariff for customers with small distributed generation facilities and electricity networks were required to add this tariff to their network price lists. If networks need to alter the structures in their approved PSS within the same 5 year regulatory period, a further round of consumer engagement should be involved.

Note on Box 9.1 The application of LRMC-based pricing to consumers with different load profiles and technologies

While we acknowledge that PV owners may avoid some network charges by reducing their demand, the extent of this cross-subsidy from other consumers depends on the percentage that have time of use tariffs, the fixed daily charge as a proportion of bills, the proportion of their demand that is met by PVs, and so on. This is without considering the dampening effect that more large-scale grid-connected renewables are having on wholesale prices (partly during peaks), as the Climate Change Authority noted in its review of the RET. This Box assumes such a cross-subsidy exists without providing evidence. Also, it is not quite correct to assume that "peak periods largely fall outside of times when the sun is brightest and solar PV generation is high." Especially on summer afternoons, there is an overlap between PV output and lower peak demand. PV systems typically produce around ¼ of total output at 4 pm in winter, and around 1/3 in summer.[1] Networks could take advantage of this by offering new PV customers a rebate for installing panels facing N-

[1] See eg http://reneweconomy.com.au/2013/revealed-rooftop-solars-big-role-in-australian-energy-markets-38580 and the APVI report referred to in http://reneweconomy.com.au/2013/time-to-get-facts-right-on-solar-and-reap-the-benefits-68517, which claims that about 20 per cent of PV output is available at 5 pm in summer.

W or W to further decrease peak demand. Finally, PV owners are usually forced onto time of use tariffs after installation, so the argument relating to flat or inclining block tariffs does not apply, although it is important that peak period time of use tariffs closely reflect actual consumption peaks.

The remainder of this submission concerns proposed reforms to distribution pricing principles.

Question 21 What would be the likely impacts on customers of making an LRMC approach mandatory?

The most significant impact of making an LRMC approach mandatory is that the revenue residual will be recovered from customers who are least able to respond to the efficient and flexible price signals. Currently distributors must only take into account LRMC in price setting which allows some flexibility around the allocation of revenue to tariffs. As Rule 6.18.5(b) states "A tariff, and if it consists of 2 or more charging parameters, each charging parameter for a tariff class … must take into account the long run marginal cost for the service or, in the case of a charging parameter, for the element of the service to which the charging parameter relates".

A review of the 2013 annual pricing proposals of all 12 electricity distributors indicates that most had a revenue residual to allocate above LRMC. If LRMC were mandatory the resulting residual revenue will need to be allocated in accordance with the rules. Under rule 6.18.5(c) if a distributor is not able to recover its expected revenue (ie. it has a residual) it must recover that revenue with minimum distortion to efficient patterns of consumptions. This can only mean that revenue will not be recovered on tariffs and customers that can respond to price signals, such as those that have demand and peak energy charging parameters. This has significant implications for customers who are currently on tariffs with pricing structures that don't signal marginal network cost (such as block structure tariffs). This issue was identified in the Power of Choice review but was not included in the SCER rule change.

Question 22 What would be the impacts on DNSPs of making an LRMC approach mandatory? Does it result in increased compliance risk?

There would be a number of impacts on distributors if the LRMC approach were made mandatory. A review of the 2013 annual pricing proposals for each distributor indicates that using LRMC to set prices is a far from straight forward process, and that some inconsistencies exist across each region. Essential Energy states that "the LRMC approach to pricing is difficult to implement". This is because economically efficient marginal costs and long run average costs were only found to be equal in locations where there is network congestion. SP Ausnet states in its proposal "It is of course immensely difficult to accurately measure the long run marginal costs of consumption". It explains that there are challenges involved in obtaining accurate demand forecasts and cost estimates. Locational differences, accurate timing of investment decisions, and future technological advances are also given as limitations on using LRMC to set prices.

A number of distributors highlighted the fact that price setting with LRMC should only be used for charging parameters that signal marginal costs, such as demand charges or peak energy charges. Citipower says it "signals the long run marginal cost of supply through those tariff charging parameters with the greatest price elasticity of demand, namely the variable consumption charges that are based on the customers energy use and maximum demand". SA Power Network says that using LRMC on fixed standing charges will be "unlikely to affect consumer consumption patterns". However the SCER rule change will require that all charging components be based on LRMC. If the LRMC were applied to all charging parameters, including fixed and off-peak energy charges, it would dampen the impact and intention of using LRMC as a price signal.

There were significant differences in the amount of information provided by each distributor in the NEM when complying with rule 6.18.5(b) (LRMC) in the current year pricing proposals. While several distributors published LRMC values by tariff class in their proposals, only two distributors showed LRMC values by charging parameter. No distributor put the LRMC estimates for all of their tariffs and charging parameters in the public domain. Four distributors submitted their LRMC models to the AER confidentially. Five distributors did not show any LRMC values at all in their annual pricing proposals. It can only be speculated that these disclosure shortcomings are a result of the challenges experienced when using LRMC to set prices. If the SCER rule change is adopted and prices are to be based on LRMC a more consistent disclosure of this information will be necessary.

Question 24 Should LRMC be defined? If so, what level of detail would be appropriate?
Question 25 Should one methodology apply to calculating LRMC or should multiple methodologies be allowed? Which is/are the most appropriate methodology(ies)?

If LRMC is to be mandatory in price setting then it should be defined. A review of the current year pricing proposals from each distributor indicates the average incremental cost (AIC) method is the most commonly used formula for the calculation of LRMC. Ausgrid, Endeavour, Essential Energy, Jemena, Energex, United Energy and SA Power Networks have all selected this method for their LRMC calculations. Citipower and Powercor have taken a similar approach as it has "estimated its LRMC for each tariff class by annualising its cost of augmenting capacity … and scale growth in operating and maintenance costs associated with network augmentation, per unit of additional capacity provided". No other calculation method has been confirmed as being used in the current year pricing proposals (including the Turvey method).

Note however that the AIC method, while by far being the most common method of calculating LRMC among distributors, does have difficulties when implemented in practice. A broad definition of AIC is that it is the present value of capital and operating costs divided by the present value of incremental demand. In practice, using demand in this calculation only works when demand is increasing. When demand is flat or in decline it will potentially create erroneous results. To allocate building block revenue to negative charging parameters would mean that significantly more revenue would need to be allocated to other tariffs and charging parameters. This would exacerbate the problem of a revenue residual being recovered on customers who are not able to respond to cost reflective price signals.

At a system level, peak electricity demand in the National Electricity Market has recently been either flat or declining. In its 2013 National Electricity Forecast Report, AEMO forecasts that an overall reduction of 728 MW in peak demand will occur in the current financial year. This is due to the rise in solar PV installation numbers, increased energy efficiency projections as a result of building standards, and changes in forecasts for industrial projects. While distributors calculate LRMC at a much more local basis, these trends will create difficulties with marginal cost and network revenue allocation calculations while current trends continue.

Question 26 Should the AER be required through a guideline to specify the methodology or methodologies of calculating and applying LRMC?

SCER's proposed amendments to the Distribution Pricing Rules do not provide a methodology for calculating LRMC. If LRMC is to be mandatory in the price setting, it would make sense for the AER to specify a methodology.

Question 27 What is the impact of coincident peak demand on network costs and how are these additional costs currently recovered in network tariffs?

Coincident peak demand is usually defined as the highest value of the summated half hourly demand for a group of customers (or for one customer with multiple meters). Coincident peak demand does drive network augmentation costs but only when measured at a local level. For example the coincident demand for all customers located under the same zone substation is a good indicator of the need for investment in that substation. Coincident peak demand as measured for an entire network does not necessarily have a correlation with network augmentation costs because it represents the aggregated trends across many substations. Note that coincident peak demand is not a useful indicator for network asset replacement decisions.

As mentioned earlier in this submission, network tariffs are in effect place holders for the recovery of building block revenue and do not represent actual or forecast costs. It is the apportionment of revenue to each tariff and charging parameter that is carried out on the basis of cost. In addition, given that the network tariffs for a distributor are not usually differentiated by location (or substation) it would be difficult for these locational costs to be captured and represented explicitly in each tariff. The costs that are captured will represent a high level aggregation of the demand driven costs across the entire network.

Question 28 How should LRMC pricing reflect additional costs associated with coincident peak demand and what are the practical impediments to DNSPs adopting tariffs that reflect coincident peak demand?

There are two main challenges with adopting LRMC in tariffs using coincident peak demand. The first is that coincident peak demand must be calculated on a locational basis to provide a useful indication of a need for network augmentation. However network tariffs usually aren't determined at such a level given the significant complexity and transaction costs involved (not to mention an adverse impact in the customer experience). The second challenge is that where demand is declining or flat, it could give LRMC values that are erroneous. This was explained in more detail earlier in this submission.

Question 29 How important are locational pricing signals for distribution networks? Are locational pricing signals for some types of customers more important than others?

Locational price signals are important for distribution networks given that network augmentation and replacement costs are driven by local considerations. This is the case for all types of customer classes. However limitations exist in providing locational prices (see question 30).

Question 30 What are the practical impediments to DNSPs adopting tariffs that reflect locational pricing signals?

One of the most significant impediments to network tariffs being determined on a locational basis is an increased complexity and a resulting poor customer experience. A review of the network price lists for all distributors shows that there are currently 437 different network tariffs in the National Electricity Market. This excludes public lighting and site specific customer pricing. Some of the reasons for such a large number of tariffs include; feed-in tariff schemes, obsolete tariffs, stand-by tariffs, and the need to show different tariffs by metering and voltage types. There is also a wide range of different pricing structures offered across the network areas such as; seasonal demand, time of use, inclining blocks, and critical peak pricing.

If prices were to be calculated on a locational basis there is no doubt that the complexity of network pricing would increase. More complexity will add to the delays in the preparation of annual pricing proposals and the time required by the AER to approve a proposal. Electricity retailers have also had significant difficulties in accommodating existing network price structures in their billing systems, as was seen in the submissions to IPART's consultation in 2012.

There are also equity implications in network prices being calculated at a locational level. For example, if a residential consumer had electricity rates significantly higher than a neighbour it would appear to that consumer that they are being disadvantaged, particularly if they had sought competitive offers from retailers and couldn't match the lower rates.

Please see also the note on VNM at the end of this submission.

Question 31 Is an additional principle required to further encourage network prices which are based on the drivers of network costs to the maximum extent possible?

If any additional principle were included in the price setting it should take into account the fact that network tariffs are effectively placeholders for the recovery of building block revenue, not values that represent actual costs. However actual costs can be used to apportion the building block revenue across tariff classes, tariffs and charging parameters. Therefore it is the proportional differences among tariffs and charging parameters that can represent network costs. For example across tariffs customers on a low voltage tariff use more of the network than customers connected at a high voltage level. Across charging parameters customers using electricity mostly in peak times are likely to be contributing to network augmentation costs more than those customers using electricity in off-peak times. In this way tariffs can send price signals to consumers as a consequence of these relative differences.

Question 32 What are the pros and cons of using a Ramsey pricing approach or a postage stamp pricing approach?

There are significant problems in using a Ramsey pricing approach to allocate a revenue residual. As electricity demand falls in the National Electricity Market, the size of the residual allocated to charging parameters will increase. This is because in an environment of declining demand, LRMC values will trend downwards. To allocate revenue so that it "minimally distorts efficient patterns of consumption" means that customers without flexible, efficient and cost reflective prices will be worse off. In addition, distribution businesses should not need to use a Ramsay pricing approach in price setting since from July 2014 they will be recovering distribution revenue under a revenue cap. This means that there is no risk to volumes for the distributors because any revenue that isn't recovered in one year (due to falling demand) can be recovered in the subsequent year.

A postage stamp allocation methodology is a better approach to allocating a revenue residual. This is because the excess revenue is allocated to all customers, on the basis of the same dollar per unit value. Given that many small customers do not have metering capable of measuring a quantity other than energy, it is suggested that any postage stamp allocation be made on a dollar per kWh basis and not a dollar per kW basis.

Question 33 Are there any other pricing approaches that should be considered to recover residual network costs?

The Power of Choice review stated that small customers will not be required to move to flexible, efficient and cost reflective prices unless they elect to do so. However under the proposed SCER rule changes, the revenue that is not able to be recovered on customers with LRMC based pricing will be allocated on tariffs and charging parameters such that it "minimally distort efficient patterns of consumption". This means excess revenues will be recovered on customers who do not have pricing based on marginal costs, such as customers receiving anytime energy rates (in cents per kWh), or standing charges (in cents per day). Therefore it is likely that small customers will be impacted by these proposed changes with higher network tariffs even though the Power of Choice recommended that they should be exempt from these changes.

Question 34 Should an approach or approaches be specified in the NER or an AER guideline?

If LRMC is to be mandatory in price setting then the approach for allocating the revenue residual to tariffs should be defined. This is particularly important in an environment of declining demand and where LRMC in many cases will not be able to represent network costs. As mentioned earlier in this submission the LRMC approach can capture network augmentation costs in situations where demand is increasing. Network replacement costs are not captured adequately by the LRMC approach, particularly in situations of flat or declining demand.

Question 37 Should a requirement of DNSPs to take into account the impact of tariffs on consumers be included in the pricing principles?

Yes. The Power of Choice review recommended that small customers would not receive flexible, efficient and cost reflective prices unless they chose to. The current rule changes from SCER propose an arrangement where small customers would be impacted by the transition to cost reflective pricing. This is because a revenue residual will be allocated to tariffs so that it minimally distorts efficient patterns of consumption. In other words it will be allocated to customers who are least able to respond to the price signals. Given these implications, clause 6.18.5(b)(2)(ii) from the SCER rule change becomes very important, and should be included. In addition 6.18.5(c) of the pricing principles should be amended so that is consistent with the Power of Choice. The revenue residual should be allocated on a postage stamp basis.

Question 38 If a requirement is included, does the proposed principle provide enough guidance on how it is to be complied with, or would an AER guideline be useful?

If LRMC is to be mandatory in the price setting it will be important to have an AER guideline that defines how LRMC is to be applied and how the residual is to be recovered from customers (in the absence of any changes to rule 6.18.5(c)). Currently there is not sufficient information in rule 6.18.5(b)(2)(ii) to determine how distributors should have regard to customer impacts.

Further initiatives could be included in the AER guideline to protect small customers who are unable to respond to efficient, flexible, cost reflective prices. Even if the revenue residual is allocated on a postage stamp basis, small customers who have not elected for cost reflective prices will still be impacted (they will be recipients of the postage stamp allocation). This rule change consultation presents a unique opportunity for a uniform approach for small customer distribution pricing across all 12 distributors in the NEM. Consideration should be given to a new pricing principle that requires all distributors to offer a hardship tariff. This tariff would be exempt from the allocation of excess revenue under rule 6.18.5(c). The price structure would be as simple as possible and ideally would feature a single variable rate and possibly no standing charge. Eligibility for the tariff would be defined in Part 3 of the Retail Rules and would be coordinated as part of each electricity retailer's mandated customer hardship policy.

Question 39 If a requirement is included, does the proposed pricing principle conflict with other principles within the NER?

Currently clause 6.18.5(b)(2)(ii) from the SCER rule change requires that distributors have regard to how changes may impact retail customers. A "having regard to" condition is unlikely to conflict with other principles within the NER.

Question 40 Should network tariffs reflect transmission pricing signals? If so, what would be the most appropriate way for different types of network customers?

Transmission network service providers are required under the NER to structure their prices into locational, non-locational, and common service charges. These price signals are designed to influence efficient consumer behaviour. However given that distribution network tariffs are usually not calculated on a locational basis, it would not be useful to require distributors to structure their tariffs so that they reflect transmission pricing. However not all distributors show their network prices separated into distribution and transmission components. It would be worthwhile if the Distribution Pricing Rules required distributors to show these prices separately in the annual pricing proposals. This will enable external stakeholders to determine if transmission revenues have been allocated consistently across a distributor's tariff classes, tariffs and charging parameters.

Question 41 Is the change to a mandatory requirement to group customers into tariff classes likely to achieve the desired outcomes?

Amended rule 6.18.3(d) from SCER is unlikely to produce any changes in the way that distributors construct tariff classes. The previous version of this rule was adequately binding and it enabled customers to be assigned to tariff classes on the basis of economic efficiency. It is in fact rule 6.18.4(a)(1) that provides the specific guidance on how to establish tariff classes. Customers should be allocated to tariff classes based on the nature and extent of their usage and the nature of their connection to the network. Distributors use voltage level, meter type, annual energy consumption, and residential/business classifications as the main criteria of allocating customers to tariff classes.

Question 42 Is the change to a mandatory requirement to group customers into tariff classes likely to result in inconsistencies within the NER or with any jurisdictional instruments or requirements?

Distributors have been grouping customers into tariff classes ever since the Distribution Pricing Rules were introduced. This was so that they could comply with the side constraint provisions in rule 6.18.6. Therefore SCER's amendments to rule 6.18.3(d) are unlikely to see any changes to tariff classes and there will not be any inconsistencies within the NER or with jurisdictional instruments or requirements as a result of this change.

Question 43 Is the proposal to apply side constraints across regulatory periods likely to materially benefit consumers by protecting them from price shocks?

The proposal to apply side constraints across regulatory periods is unlikely to materially benefit consumers by protecting them from price shocks. This is because the side constraints only apply to tariff classes, and not to individual tariffs or charging parameters.

Tariff classes usually represent a group of tariffs. For example most distributors have a residential tariff class or a low voltage tariff class. A number of different small customer tariffs will be used to recover revenue for each of these tariff classes. A residential tariff class may have one tariff with a block structure, and another tariff with a time of use structure. A low voltage tariff class is likely to have separate tariff or tariffs for residential customers compared to business customers.

Application of the side constraints rule 6.18.6(b) in the pricing proposals will only limit the annual variations of revenue across tariff classes by 2%. The side constraints do not restrict revenue rebalancing across tariffs within a tariff class. They also do not restrict revenue rebalancing across charging parameters for any given tariff. This is an important omission in the price regulation of distribution revenue.

In the current regulatory period consumers have experienced sudden rebalancing of their charging parameters. The existing Distribution Pricing Rules and those proposed by SCER do not present ways of limiting these sudden price shocks. While the new customer consultation rules from IPART and SCER will give consumers an early warning of future changes it also important that these reforms extend to the regulation of prices. This will avoid the significant variations across charging parameters that have occurred since the introduction of the Rules in 2009. Amendments to these Rules are urgently required in this area.

Note that both the SCER rule change and the Power of Choice review discuss removing all side constraints from the Rules. This was based on an assumption that the proposed Pricing Structures Statement will provide adequate regulation of pricing structures and tariff movements at the start of the regulatory period. Until the PSS is finalised it should be acknowledged that there are currently no rules preventing significant revenue rebalancing across charging parameters or tariffs within a tariff class. One solution is to continue to regulate pricing on an annual basis by introducing additional side constraint limits to both charging parameters and individual tariffs within a tariff class.

Question 45 Are there likely to be implementation issues in applying side constraints across regulatory periods?

The Pricing Structures Statement will define a distributor's charging parameters for the next five years. If the side constraints apply between two five year periods then it will create complications in situations where a distributor moves tariffs in or out of existing tariff classes, creates new tariff classes, or removes old tariff classes.

Question 46 Should network tariffs of customers with interval meters or other types of time-based meters be subject to side constraints?

Yes. A number of small customers have interval meters and it is important that price shock measures such as side constraints are in place for these consumers. This submission's response to question 43 provides suggestions on ways to improve the side constraints rule.

Additional note on VNM

While the consultation paper flags the prospect of network tariffs differing according to the LRMC of augmentation across networks, it does not discuss the equally important concept of tariffs varying according to the distance between generators and consumers. This is an important element of the move towards a more decentralised energy system, with more distributed generation not only being used onsite or behind the meter but also exported into the grid. This could involve several scenarios:

1. A commercial scale rooftop PV system distributing electricity to metered tenants in apartment buildings or shopping centres (ie using the network only at the meter).
2. A cogen or trigen power plant using a small distance of the network to distribute electricity in a commercial precinct.
3. A community solar or wind project which wishes to distribute electricity to local members on the same feeder line or within the same zone substation area.

In each of these cases, the decentralised energy project will involve limited use of the distribution network, and no use of the transmission network. As well as avoiding TUoS, such projects should also be entitled to lower distribution network charges. The mandatory use of LRMC as the methodology for determining tariffs would help to establish this principle,

However, the introduction of VNM into the NEM may require a rule change, as there is nothing in the existing rules or the IPART/SCER request that would mandate the introduction of a VNM discount for local generation and consumption – and networks currently have no incentive to introduce them. (Whether they will result in lower network revenue is arguable, since many of the projects that would take advantage of a VNM tariff would not be financially viable without it, and it could be an alternative to such consumers going off-grid as an alternative. The equity implications of VNM will be discussed in the work ISF is currently undertaking for TEC.)

TEC encourages the AEMC to include VNM in the scope of the current rule change request.

Conclusion and recommendation

Ellipson and TEC support the move towards more cost reflective tariffs, but consider that mandating the use of LRMC in price setting may be a problematic way to achieve them. This is especially the case since LRMC is a way of calculating overall network costs rather than apportioning revenue to different costs that the network incurs. Under the SCER rule change it is likely that a significant revenue residual will need to be allocated over and above the underlying LRMC values for each tariff and charging parameter. The current approach does not give certainty on how this residual should be allocated, or a clear indication of impacts on consumers.

We therefore recommend that the AEMC consider whether this rule change should include other ways of calculating cost reflective network tariffs. For example, the NER transmission pricing rules use optimised replacement cost combined with a prescriptive method for allocating regulated revenue to each cost category. If the principle of cost reflectivity is to be successfully included in the Distribution Pricing Rules, a wider review of costing methodologies should be considered, combined with a clear approach on how building block revenue should be allocated to each cost reflective tariff and charging parameter.