TasNetworks
Delivering your power

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Mr Arek Gulbenkoglu
Acting General Manager, Distribution
Australian Energy Regulator
GPO Box 520
Melbourne Victoria 3001

Dear Arek

RE Assessing distributed energy resources (DER) integration expenditure

TasNetworks appreciates the opportunity to provide comments to the Australian Energy Regulator (**AER**) regarding the AER's approach to assessing the expenditure on the integration of DER that distribution network service providers (**DNSPs**) put forward as part of their regulatory proposals. Although TasNetworks' expenditure on DER integration has been modest to date compared to its expenditure overall, we have already seen instances where customers' use of DER – mainly in the form of photovoltaic (**PV**) solar panels – has required localised network augmentation, such as the installation of uprated transformers to maintain voltage stability, the cost of which has for the most part been borne by the wider customer base, rather than the customers installing DER.

With the uptake of DER only likely to increase, now is an appropriate juncture to consider the way in which DER expenditure is assessed by the AER, particularly as the rate at which DER is being adopted, as well as the rate of technological and market change, is such that expenditure on DER integration may have a much shorter economic lifespan than has previously been the case for network assets.

At the same time there is also a need to consider the regulatory framework that determines how the cost of DER integration is recovered from customers. The open access regime for the connection of generators, for example, sees the cost of delivering the energy injected into distribution networks by customers with DER recovered only from customers that consume energy, with the result that even cost reflective network pricing does little to signify to customers with DER (or those contemplating an investment in DER) the value of the electricity grid as a trading platform and 'back-up' system. Further, with customers who install micro-embedded generation also exempt from contributing to the cost of any network augmentation required to support the injection of the energy they produce into the distribution network, those costs are being shared amongst the wider customer base, even though the vast majority of customers neither have DER nor currently receive any real benefit from the DER installed by their neighbours.

Under the National Energy Rules (**NER**), retail customers with micro-generation facilities "should be treated no less favourably than retail customers without such facilities but with a similar load profile". The widely acknowledged cross-subsidisation of customers with PV solar panels by customers who do not have solar panels suggests that, far from being disadvantaged, the reverse has occurred, and it is important that in the future customers without DER are not treated less favourably by the rules governing the economic regulation of distribution services and the connection of retail customers than customers with DER.

We also note that the advent of metering competition and the prohibition of DNSPs from involvement with anything behind the meter has meant that DNSPs no longer have free access to data about the operation of DER appliances that have the potential to have a significant impact on the operation of their networks and the provision of standard control services, yet are expected to manage those impacts in order to limit any outcomes that are detrimental to customer service. That networks are currently expected to pay for that information is inconsistent with the causer pays principle, in that networks are potentially going to have to pay customers with DER for the information needed to address issues caused by those very customers. TasNetworks is supportive of the idea that there should be a standard set of metering data, other than just the minimum data needed for billing purposes, that DNSPs are given access to so that they can efficiently provide standard control services to all customers without requiring customers without DER to pay for that information.

Enclosed with this letter is an attachment (**Attachment A**) which contains TasNetworks' feedback regarding the topics raised in the consultation paper released by the AER on 19 November 2019. We also support the comments made by Energy Networks Australia in their response to the AER's consultation paper.

Once again, we thank the AER for the opportunity to contribute to the discussion regarding the means by which DNSPs' DER integration expenditure forecasts are evaluated by the AER. To discuss the views expressed in this submission or opportunities for further collaboration between TasNetworks and the AER regarding the assessment of DER integration expenditure, please contact William (Billy) Godwin, Revenue & Price Regulation Team Leader, at [redacted] or on [redacted]

Yours sincerely

[redacted]

Chantal Hopwood
Leader Regulation

Attachment A

Foundational questions

Question i

Are the assessment techniques outlined in the AER's Expenditure Forecast Assessment Guideline (the EFA Guideline) sufficient to assess DER integration expenditure?

Under the current EFA Guideline, the AER uses a combination of benchmarking, trend analysis, predictive modelling and engineering reviews to assess networks' capital expenditure (**capex**) forecasts, with larger capital intensive projects assessed using the Regulatory Investment Test – Distribution (**RIT-D**).

TasNetworks considers it important that the AER has at its disposal a range of tools with which to assess DER integration expenditure forecasts, as DER integration is likely to throw up a number of challenges not presented by other categories of expenditure. For example, the EFA Guideline currently talks of evaluating (traditional) network augmentation expenditure (**augex**) in the context of demand forecasts. Yet demand, specifically growth in demand, does not appear likely to be a driver of DER integration expenditure. This is demonstrated by the fact that networks are already having to install uprated transformers, and different types of transformers, not in response to load growth but to maintain stable voltages, due to the variability introduced by the intermittent injection of electricity generated by PV solar panels.

Expenditure on DER integration is also likely to include investment on Information and Communications Technology (**ICT**), for which the AER has only recently devised a bespoke assessment methodology. The AER's assessment of DER integration expenditure will need to be sufficiently flexible to potentially draw on this (and other) assessment methodologies that are not unique to DER integration, but have the potential to inform the assessment of DER integration expenditure forecasts.

It is questionable, therefore, whether assessment techniques that are unique to DER integration expenditure are actually required, given the range of tools already at the AER's disposal, especially as viewing DER expenditure in isolation potentially carries its own set of risks. However, some of the AER's existing methodologies might require modification in order to adapt them to the assessment of DER integration expenditure.

The benchmarking techniques used in relation to other categories of network expenditure may need to be modified for the purposes of assessing DER integration expenditure. For example, it might prove necessary to factor in measures of DER hosting capability or the number of customer connections with DER as benchmarking outputs, in addition to the measures like demand and energy throughput that have been used in the past. There are also likely to be significant differences between networks in terms of their current capacity to host DER (which is largely a legacy of network structure and past investment decisions), as well as differences in the demand for DER hosting capacities in the future – as evidenced by the marked difference in the take-up of PV solar panels by residential customers in different states and territories) – differences which will make benchmarking in relation to DER integration a difficult exercise.

TasNetworks, therefore, urges caution in interpreting the results of trend analysis and benchmarking in relation to DER expenditure, noting that benchmarking arguably works best during periods of stability and DNSPs are operating in an environment in which DER integration expenditure, as the AER flags in its consultation paper, is expected to rise over time.

There seems little reason to apply a RIT-D approach to DER integration expenditure except in cases where DER integration projects or programmes meet the criteria that would see a RIT-D used for other categories of capex. Even then, however, a RIT-D test may be too cumbersome, particularly in cases where a quicker, more flexible approach to DER integration (and the assessment of the expenditure involved) may be required. Satisfying the requirements of a 'traditional' RIT-D may also be more difficult in relation to DER integration expenditure, by virtue of the fact that the widespread use of DER makes accurately forecasting of metrics like load factor and maximum demand more difficult.

The RIT-D approach was also conceived with expenditure on the sort of assets needed to the serve the long-term interests of consumers of electricity in mind. The rapidity of the uptake of DER and the resultant changes in customer behaviour, as well as the rate of technological and market change, is such that expenditure on DER integration may have a much shorter economic lifespan. The network capabilities that customers want now and need in order to realise value from their investment in DER is unlikely to be what customers want in the not-too-distant future. For example, customers with their own micro-embedded generation may currently want to export as much of the energy they generate as they can, but may not want or need the network to support the same level of exports in the future, if batteries become cost-competitive with other options for using their excess solar generation.

The RIT-D is also couched in terms of identifying the 'best way' to meet the need for network investment, whilst meeting required service standards. However, network service standards are currently focussed on serving load, rather than factors like the capacity to host DER, meaning that any RIT-D applied to DER integration expenditure proposals may need to factor in a different set of network services.

Question ii

What form of guidance should the AER include to clarify how our assessment techniques apply to DER integration expenditure?

If the AER intends using benchmarking techniques to assess DER integration expenditure, DNSPs will require sufficient information to understand the methodology, including the data requirements (so network businesses can ensure they are capturing the required data in a reliable fashion), as well as access to the model(s) to enable networks to undertake their own benchmarking.

A guidance note illustrating what the AER considers to be an appropriate standard of business case in relation to DER integration expenditure would be a useful resource although, as noted elsewhere in this submission, there is no need for prescription in this regard.

Questions

Question 1 – Information provision

What information is reasonable and necessary in identifying and evidencing the impact of DER on the demand for standard control services and hence on maintaining the quality, reliability or security of supply of standard control services?

There are three main elements to the information required to enable DNSPs to accurately identify and evidence the impact of DER on the demand for standard control services and on the safety, security, reliability and quality of the services provided by the shared network. Those three elements can be summarised as:

- information identifying the location and specifications of the DER deployed on customers' premises across DNSPs' networks, in particular small-scale generation and storage;
- data explaining customer behaviour and their use of DER; and
- data describing the performance of the network in the delivery of standard control services, including frequency, voltage, consumption and demand data collected on a time of use basis.

Much of that information is not currently held, gathered or used by TasNetworks during the normal course of business, meaning that TasNetworks – like other DNSPs – is likely to be heavily reliant on information sourced from third parties, such as metering data providers, the Australian Energy Market Operator (**AEMO**) and DER aggregators, if it is to undertake robust analysis of the impacts of DER and identify the extent to which the business' expenditure is being driven by DER integration.

It will be necessary for networks to have access to at least a basic level of data in order to evaluate network augmentation options associated with DER, such as time of use voltage data at a feeder or even street level.

TasNetworks acknowledges that other DNSPs in Australia may already have access to more of the information needed to identify and evidence the impact of DER on the demand for standard control services. However, in general terms TasNetworks currently lacks the information required to identify the extent to which DER causes, for example, voltage or frequency issues around its network. This is due to Tasmania's meter fleet for residential and small business customers still being largely comprised of accumulation meters – although this is changing – and the fact that TasNetworks' supervisory control and data acquisition (SCADA) systems do not extend to low voltage (**LV**) sections of the State's distribution network, nor are there the sensors in place that are needed to measure performance of the LV network at a local level.

Gathering the data needed to evaluate the impact of DER will require TasNetworks to either incur additional operating expenditure (**opex**) on the acquisition of metering data and data from DER providers pertaining to power quality, or invest in its own measuring/monitoring devices across the network. While either option would support greater understanding of our network's utilisation, as well as an evaluation of DER impacts, both are, however, likely to only identify the presence of power quality issues, rather than their root cause(s) and TasNetworks is conscious of the impact that additional opex has on customer prices in the near-term, compared to the smaller increases that capex solutions pose over a longer term. And again, to the extent that opex is required to analyse the impact of DER on the shared network, the cost will be borne by the wider customer base, and not by customers with DER.

In terms of identifying the installed DER asset base, even with the launch of the AEMO's DER register DNSPs will only have a partial picture of the DER being hosted by their networks. This is due to the fact that much of the information gathered by DNSPs and provided to AEMO about DER installed prior to the commencement date of the DER register is likely to be incomplete in relation to the data specified for collection in respect of new DER installations.

Nonetheless, load-related issues have traditionally been and remain the biggest driver of network augmentation spending, along with asset condition, and the level of DER being hosted by Tasmania's distribution network is not yet considered to be sufficient to be a driver of material augex, or warrant the additional expenditure on the acquisition of data to undertake widespread analysis of the impact of DER on the Tasmanian distribution network.

In the future, however, the AER will need to provide a mechanism for this type of expenditure to be factored in to DNSPs' regulatory determinations, especially noting the trend in terms of embedded generation uptake and the increasingly widespread use of advanced meters. Or, preferably, DNSPs should be given access to the data they need to understand the impact that DER is having on the provision of standard control services, so that they can efficiently provide standard control services to all customers without requiring customers without DER to pay for that information.

Question 2 – Options analysis

What range of options should DNSPs consider for DER related investments? Does the RIT– D provide the appropriate starting point for this analysis?

Notwithstanding reservations about a RIT-D test potentially being too unwieldy to serve as the basis of analysing DER related investments, particular investments that are required to address localised rather than wider systemic issues, TasNetworks considers that the RIT-D requirements regarding options analysis are sufficient for the purposes of evaluating DER integration plans.

However, in evaluating alternatives to network augmentation as a means of integrating DER, TasNetworks believes that the allocation of risk will be particularly important. For example, in the event of a significant increase in the number of electric vehicles (**EVs**) on Australian roads, DER orchestration – managing the charging of electric vehicles – may be identified as the most efficient way to resolve a localised network issue. But in implementing the preferred solution, which will carry with it some cost, if the DNSP is unable to recruit sufficient customers to participate in the EV charging regime, there is a risk that, having failed to successfully mitigate the network issue, the DNSP will have to resort to a traditional network augmentation solution. The issue of who bears that risk and how it is accounted for will be a key factor in assessing DER related investments.

TasNetworks also notes that the increased prevalence of DER will require DNSPs to have a certain minimum capability, such as SCADA systems and Distribution Management Systems (DMS), if they are to be in a position to consider using solutions like DER orchestration to alleviate localised (or global) network issues. While DER integration issues are often likely to be localised, it is unlikely that one instance of a localised DER orchestration opportunity will justify the cost of a DNSP gaining the capability to engage in DER orchestration. This suggests that DNSPs may be required to invest in significant analytical and control systems to enable them to integrate DER into their networks in the future, even though the immediate business case for doing so may not stack-up using a traditional RIT-D approach to assessing the investment.

Question 3 – Sampling and modelling

Electricity networks have utilised sampling and modelling techniques to forecast energy demand and consumption for decades. These processes have proven effective for large cohorts of consumers where diversified behaviours can be predicted with sufficient accuracy.

Is it reasonable to assume that sampling and modelling techniques will play a part in developing dynamic models of the electricity networks?

It is reasonable to assume that sampling and modelling techniques will play a part in developing models of electricity networks in the future. However, it is not clear the extent to which they will help with the analysis of often localised DER related issues. That uncertainty is partly due to a lack of data needed to reliably assess how diverse the behaviour of customers with DER is currently, and partly due to the fact that even if the behaviour of customers with DER could be predicted with sufficient accuracy to be useful, as DER technology changes new behavioural paradigms will quickly emerge that render previous thinking about customer behaviour outdated.

Through TasNetworks' *emPOWERing you* trial of time of use network tariffs and advanced meters, for the first time we gained visibility of quality of supply metrics like voltage data and, as a result, identified a program of investment in the geographical area in which the trial took place. We expect that this is likely to continue to happen as advanced meters become more widespread in Tasmania. However, the same data also showed considerable behavioural differences between outwardly similar customers, demonstrated by their vastly different responses to time of use pricing signals, including different responses from customers at a feeder level. This suggests that modelling the behaviour of large cohorts of DER customers may prove extremely difficult, and that DER modelling is likely to be at its most robust when undertaken at a local level.

Some traditional approaches also may not be suited to the analysis of DER impacts on networks. For example, the EFA Guideline talks of evaluating augex in the context of demand forecasts, but demand – as difficult as it is to forecast accurately – does not appear likely to be a driver of DER integration expenditure, and the interaction to DER with the network only makes the forecasting of demand (and load) a more difficult exercise than it may have been previously. As retail customers potentially become increasingly less homogenous in terms of their behaviour through their use of DER, network modelling will need to account for that increase in diversity. The entry of DER aggregators into the Tasmanian electricity market is also likely to impact on customer diversity, and will introduce another element to network modelling in the future.

Given the range of factors which are likely to drive expenditure on DER integration, including the differences in hosting capacities and consumer demand for DER between networks, it is unlikely that using techniques akin to the AER's repex (replacement expenditure) modelling is going to be yield robust estimates of DER integration expenditure that will stand up to comparison across such disparate businesses. This situation is exacerbated by the frequently localised nature of network issues arising from the use of DER, which require localised responses rather than network level responses. Having robust modelling techniques available to evaluate the impact of DER on the provision of standard control services in a defined service area and the need for augmentation would be extremely advantageous for networks in preparing their regulatory proposals. However, undertaking network wide modelling of DER impacts is unlikely to yield the sort of insights that the AER might be hoping for, or robust alternative estimates of DER expenditure.

Question 4 – Non-network options

Distributed energy resources are, by definition, located at the end of the electricity network. Typically networks have less visibility of this part of the network.

What approaches or information is reasonable to assess whether DNSPs have considered purchasing the necessary information from metering or DER data providers rather than building their own assets and systems?

Any decision taken by TasNetworks to acquire data, whether it be by purchasing it from a data provider or through building its own systems and assets to capture the data, would be subject to the development of a business case, a business case that would include analysis of the competing options.

As is the case with the AER's evaluation methodology for non-network ICT capex assessment, however, the AER should permit DNSPs to apply their own internal governance frameworks in determining whether a business case is produced for the purchase of information needed to analyse the network and customer impacts of DER. We would also expect that that those business cases, and the level of decision support therein, should be sufficient for the AER's purposes if they meet TasNetworks' own governance framework.

In cases where a business case is not created, as is the case with ICT expenditure we anticipate that the AER would request further information to test the prudency and efficiency of the purchase of data versus the acquisition of the same data through other means. The level of supporting information being sought by the AER would be commensurate with either the quantum of the expenditure or the difference between the costs of purchasing the data and the alternative means of acquisition.

TasNetworks considers that the AER should not need to be prescriptive in this regard.

Question 5 – Policy and standards

The optimisation of DER can be improved through many different approaches. Factors such as tariff reform, connection standards, technical standards and energy efficiency standards can greatly affect the way that DER operates on the network and impacts on network performance.

How should these options be integrated with the development of network DER proposals?

TasNetworks notes the AER's commentary in support of its *Request for submissions* about the contribution that network tariff reform, particularly the use of cost reflective network pricing, is making to the integration of DER, by enabling customers to make informed decisions about the costs and benefits of deploying DER.

As stated in the letter accompanying this submission, cost reflective network pricing currently does not fully signify to customers with DER (or those contemplating an investment in DER) the value of the electricity grid as a trading platform and 'back-up' system. This is because under the NER the cost of delivering the energy injected into distribution networks by customers with DER is currently recovered only from customers that consume energy, and customers who install micro-embedded generation are not required to contribute to the cost of network augmentation needed to support the injection of the energy they produce.

While to some degree we try to demonstrate the value of network connection through the fixed charging components of our network tariffs, significantly increasing the ratio of network costs recovered through fixed rather than volumetric network charges would weaken the price signals sent to customers through the volumetric time of use charging parameters applying to load. So, without changes to the regulatory framework for the economic regulation of DNSPs and electricity connection for retail customers, network tariff reform (with its focus on load) is unlikely to have as much of an impact on DER integration as the AER appears to be anticipating.

Even with network prices which better signal the value of the grid to customers with DER, relying too heavily on network tariff reform to facilitate DER integration is not without risk. Network tariff reform, particularly in a market with a requirement for postage stamp, is rendered a relatively blunt instrument when seeking to address localised DER integration issues. And to whatever extent network pricing reform might have the potential to resolve localised or network-wide DER integration issues, if sufficient customers are not able to be recruited to the required tariffs, or do not change their behaviour in the desired manner in response to those tariffs, then that muted response to network tariff reform may mean that the DNSP is unable to avoid having to implement a traditional solution to DER integration that involves network augmentation. As TasNetworks' *emPOWERing You* trial of demand-based time of use network tariffs and advanced meters demonstrated, not all customers are engaged with electricity pricing, and even amongst those that are there can be a wide range of responses to network pricing signals, with some customers showing no measurable response and others acting seemingly counter-intuitively.

The technical, connection and energy efficiency standards applying to DER are set independently of DNSPs. While DNSPs' are required to comply with those standards, and they might inform the asset management plans underpinning regulatory proposals, including DER integration expenditure plans, there is no need to prescribe how these factors should be integrated with the development of network DER proposals.

Question 6 - Cost benefit analysis

Project justifications will require detailed analysis on the costs and benefits of each option. Many of these benefits may be external to the DNSP's cost base, and may accrue directly to DER users.

What level of analysis is required?

TasNetworks considers that if there are benefits associated with DER integration expenditure that accrue directly to DER users then those benefits should not be taken into account when undertaking a cost benefit analysis of that expenditure, particularly if those DER users are not contributing towards the cost of DER integration in a way that reflects the benefits they derive, compared to customers without DER.

While increasing DER hosting capacity and facilitating the export of electricity by customers with DER may reduce wholesale electricity prices, it may also increase network costs, at least in the short term, before any network benefits, such as reductions in augex or repex, might be realised. Nonetheless, it is appropriate that market benefits be taken into account as part of any cost benefit analysis of DER integration expenditure.

However, network costs are currently the largest component of the delivered cost of electricity for most customers and reducing the largest portion of customers' bills is central to the contribution that can be made by DNSPs towards serving the long-term interests of consumers, in the form of reducing the delivered cost of electricity. The inclusion in the business case for expenditure on DER integration of benefits that accrue directly to DER users is potentially at odds with that objective. Therefore, the benefits recognised in support of DER integration should be confined to broader market benefits and those relating to the provision of standard control services by networks, and should not include benefits accrued solely by customers with DER.

Any analysis of the benefits of providing additional hosting capacity will also need to recognise that, in line with the law of diminishing return, the value of enabling the injection of additional electricity by customers with DER is likely, at some point, begin to decrease as the proliferation of DER increases, rather than remain constant.

TasNetworks does not support calls for the inclusion of any reduction of greenhouse gas emissions associated with customer uptake of DER as part of the business case for DER integration expenditure by DNSPs without also recognising that the proliferation of DER can have negative consequences for network voltages, frequency and inertia. We note that any consideration of the impact of DER on greenhouse gas emissions would also need to be based on the generation mix servicing customers in a given network service area, which is likely to change over time and in Tasmania's case is already primarily made up of dispatchable renewable generation without any of the voltage, frequency and inertia issues associated with a reliance on intermittent embedded generation.

We also do not support the Clean Energy Council's view that networks should be incentivised to integrate more DER on the grid through the AER's assessment of their capex and opex proposals. DNSPs are already incentivised to innovate, pursue savings, improve network reliability and invest in demand management, through a variety of incentive schemes and allowances, all of which are technologically neutral. It would be inappropriate to skew the AER's assessment of the DER integration expenditure plans of DNSPs in any way that interferes with the objective comparison of benefits against costs by favouring a predetermined course of action or outcome.

Question 7 – Customer benefits

With DER being able to provide services across the electricity supply chain, how should DNSPs identify and value customer benefits? These benefits can include reliability outcomes, increased export potential, greater access to energy markets, access to network support services, etc..

Should a common approach to valuing consumer exported electricity be established?

The benefits valued as part of a business case for expenditure on DER integration should be limited to benefits relating to standard control services. Benefits that do not relate to standard control services or which accrue directly to DER users should not be included in any assessment of the benefits associated with DER integration expenditure.

Nonetheless, it is in the interests of all customers that networks be able to reliably value the benefits associated with DER integration expenditure – and not just the value of the export of electricity by consumers – in order to avoid inefficient investments in DER integration and network infrastructure and ensure consumers don't pay more for network services than necessary. Noting past experience with the derivation of the value of customer reliability, which saw variations in both the methodology and the resulting estimates calculated by different parties, the use of an agreed, common methodology for the valuation of DER integration benefits – preferably developed and issued by the AER – would ensure a consistent approach is taken by all DNSPs, while hopefully recognising that the value placed by customers on particular benefits will differ between networks, and potentially even between different areas within the same network.

Question 8 – Options value

Noting the technological rate of change and the typical asset life of 65 years of many network assets, it is important to test whether current research could provide a more efficient option in the near future.

Should an assessment of emerging alternative approaches be a requirement for DER forecast expenditure? Should there be an 'options value' placed on this?

TasNetworks does not support as part of the business cases prepared for expenditure on DER integration the inclusion of formal assessments of alternative approaches to DER integration that are still in the research and development phase. The speed of technological change and the impact of new technologies and business models is difficult to forecast. As is already the case in relation to expenditure on ICT, in the event that technological change or market developments occur between the preparation of a business case for expenditure on DER integration and its implementation, networks' recursive (or iterative) planning processes will see those developments identified and used to amend those plans if the new options offer a more efficient solution.

There is no need to enshrine an assessment of emerging alternative approaches to DER integration in any guidance provided by the AER to DNSPs.

Question 9 – Shared learning and systems

The development of common platforms, communication standards and shared systems may reduce the overall cost and complexity of facilitating DER.

Should DNSPs need to show how they have considered options that leverage shared learning, common standards and common systems to provide efficient solutions, and that they have consulted and implemented learnings from prior works and trials across the NEM?

DNSPs are not required to show how they have considered options that leverage shared learning, common standards and common systems in relation to other categories of capex or opex, although it is something that TasNetworks and other DNSPs still do as a means of improving efficiency and reducing costs for customers. Therefore, it would be inconsistent to apply such a requirement to DER integration expenditure.

While it is possible that the integration of DER into different network topologies will sometimes require the use of different technologies and solutions, good business practice dictates that DNSPs are likely to continue to seek opportunities to leverage shared learnings, common standards and common systems in the interests of achieving efficiencies, without a mandated requirement to do so.

Question 10 – Rail gauge outcomes

As a corollary to the above question, it will be increasingly important for the industry to work together to provide customer outcomes that are consistent across the NEM (or with international standards if applicable).

What approaches or information is reasonable to show that any DNSP-specific communication protocols, interfaces, connection standards, etc. will not lead to increased cost and complexity for consumers and industry providers?

The electricity supply industry within Australia already successfully operates within a standards-driven framework comprising elements like standardised metering data, business-to-business communication protocols, metrology standards and standards applying to invertor operation, with which DNSPs are required to comply. Those standards are developed in consultation with industry and the involvement of DNSPs, and DNSPs' compliance with those standards, already ensures consistency across the NEM. The rise of DER makes it no less or more important for DNSPs and industry to work together to ensure the development of common platforms, communication standards and shared systems than has been the case in the past.

TasNetworks does not consider that the AER needs to prescribe any particular approach that DNSPs should take, or information that DNSPs should provide as part of their regulatory proposals, in order to show that any DNSP-specific communication protocols, interfaces, connection standards, etc. will not lead to increased cost and complexity for consumers and industry providers. Any departure from those standards in the form of a customised solution is unlikely to be undertaken without the development of a robust business case by the DNSP (or DNSPs) proposing to deviate from a standard. TasNetworks considers that the provision of that business case and any supporting information as part of a DNSP's regulatory proposal should be sufficient grounds on which to assess whether the DNSP's proposed approach will lead to increased cost and complexity for consumers and industry providers.