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24 February 2017

Mr Warwick Anderson
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Australian Energy Regulator
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Dear Mr Anderson

CONSULTATION PAPER – DEMAND MANAGEMENT INCENTIVE SCHEME AND INNOVATION ALLOWANCE MECHANISM

Ergon Energy Corporation Limited (Ergon Energy), in its capacity as a Distribution Network Service Provider in Queensland, welcomes the opportunity to respond to the Australian Energy Regulator on its *Consultation paper – Demand management incentive scheme and innovation allowance mechanism*.

Should you require additional information or wish to discuss any aspect of this submission, please do not hesitate to contact me on (07) 3851 6416.

Yours sincerely

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Encl: Ergon Energy's submission

Submission on the *Demand management incentive scheme and innovation allowance mechanism*

24 February 2017

Submission on the *Demand management incentive scheme and innovation allowance mechanism* Consultation Paper

Australian Energy Regulator

24 February 2017

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Introduction

Ergon Energy Corporation Limited (Ergon Energy), in its capacity as a Distribution Network Service Provider (DNSP) in Queensland, welcomes the opportunity to provide comments to the Australian Energy Regulator (AER) on its *Demand management incentive scheme and innovation allowance mechanism* Consultation Paper (the Consultation Paper).

This submission sets out our preferences for each of the design options proposed by the AER in the Consultation Paper, as well as an alternative option for the innovation allowance. It also responds to the questions posed by the AER in the Consultation Paper.

In developing the new demand management incentive scheme (the scheme) and innovation allowance, the AER should take into account the following principles:

- The scheme and innovation allowance should be as simple as possible to encourage market participation and to minimise the administrative burden on DNSPs.
- The AER should be mindful that multiple forms of financial incentives under the scheme may lead to confusion amongst stakeholders and may result in an inappropriate value being placed on demand management.
- Demand management is of the greatest benefit when growth is high. When growth if flat (as it is now), the immediate need for DNSPs to invest in demand management is reduced. Accordingly, so is the need to incentivise DNSPs to undertake demand management.
- The scheme and innovation allowance should not inhibit a DNSP's ability to innovate in the demand management space, or be prescriptive in the actions a DNSP can take to address the issues faced by its network. Instead, the mechanisms should focus on providing incentives to achieve the most efficient outcome for customers.
- The verification, reporting and compliance measures should be proportionate to the size of the projects being funded and/or the complexity of the scheme.

Ergon Energy is a member of Energy Networks Australia (ENA), the peak national body for Australia's energy networks. The ENA has prepared a submission in response to the AER's Consultation Paper. Ergon Energy is generally supportive of the positions contained in the submission.

Ergon Energy is available to discuss this submission or provide further detail regarding the issues raised, should the AER require.

General comments

Potential scheme design options

Our high level comments on each of the mechanisms proposed by the AER for the scheme are set out below. More detailed comments are provided in the next section.

Type 1: Mechanisms to target potential disincentives

Limiting penalties under the Service Target Performance Incentive Scheme

Ergon Energy agrees that any changes to the Service Target Performance Incentive Scheme (STPIS) should be consulted on as part of the AER's STPIS review.

Excluding innovation allowance

The innovation allowance should be treated as a revenue adjustment in the Post Tax Revenue Model (as is the case for Ergon Energy in the 2015 to 2020 period). We therefore agree with the AER's proposal to explicitly exclude projects funded under the innovation allowance from the operating expenditure (opex) building block and, consequently, the Efficiency Benefit Sharing Scheme (EBSS).

Addressing the potential bias towards network investment

As noted in the Consultation Paper, there are some features of the existing regulatory framework that may, in theory, lead to a preference towards network investment. We therefore support providing incentives to DNSPs to address this potential bias. Our positions on the mechanisms proposed by the AER are summarised below.

In the longer term, we consider there is value in exploring a total expenditure ('totex') style approach to assessing and approving expenditure allowances, such as that applied in the United Kingdom. This approach has been identified as a key area of regulatory reform in the *Electricity Network Transformation Roadmap: Key Concepts Report*[1] produced by the ENA and the Commonwealth Scientific and Industrial Research Organisation (CSIRO).

Uplift amount

Ergon Energy supports an uplift on the amount spent on a demand management project so the DNSP can receive an 'instant return' on their investment. This is the simplest scheme out of the ones proposed to address the potential bias towards network investment, and will increase the value DNSPs internally place on demand management solutions. Details on the practical application of this mechanism should be explored further at the workshop and via an exposure draft of the new scheme.

Recovery of foregone return on and return of capital

This option will be administratively burdensome if there are a large number of affected projects. We expect that a separate model would need to be established to monitor and collate information on the capital expenditure (capex) that has been deferred or did not eventuate within the period as

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[1] http://www.energynetworks.com.au/electricity-network-transformation-roadmap

a result of demand management solutions. This model would then need to calculate the forgone return on and return of capital associated with this capex over the specified regulatory control period(s).

Uplift amount proportional to the option value

Ergon Energy does not believe it is possible to reasonably quantify the option value associated with an option. We therefore do not support this approach.

Linking projects funded under the innovation allowance to the scheme

Ergon Energy supports the AER's proposal to provide an 'innovation return bonus' to DNSPs in the event they are able to translate research and development (R&D) under the innovation allowance into a viable project under the scheme. Any innovation return bonus should be dependent on the success of the innovation and acceptance of the activity into the DNSP's business as usual activities or acceptance by other DNSPs or industry bodies. It should not be dependent on the volume of demand removed as a result of applying the new methodology. The scheme will need to include detailed criteria as to what constitutes 'success'.

Recovery of foregone revenue

Ergon Energy notes the control mechanism(s) applying to a DNSP is determined as part of the Framework and Approach process and may change between periods. We therefore consider it inappropriate to discount a particular design mechanism based on the likelihood that all DNSPs will be subject to a particular control mechanism (e.g. revenue cap) in the future.

Type 2: Net-market benefit sharing

Ergon Energy sees merit in exploring a simplified version of a net-market benefit sharing mechanism.

Type 3: Mechanisms to promote competition

Incentivise distributors to provide information

Ergon Energy does not believe that providing more information to market participants will improve the uptake of demand management. We provide a substantial proportion of the information listed in the Consultation Paper, yet the response from the market to our demand management incentives has been slow.

Bidding mechanism

Ergon Energy does not support a bidding mechanism. We consider there are too many practical implementation issues to warrant this approach.

Type 4: Targets for demand management deployment

Ergon Energy does not support setting targets for demand management as they may result in demand management being contracted to meet the target and not for the efficient operation of the network. We have recently moved away from firm MVA targets in our jurisdictional Demand Management Plan.[2]

Potential innovation allowance options

Having considered the options proposed by the AER, Ergon Energy believes an alternative option comprised of a modest innovation allowance as per the current Demand Management Innovation Allowance (DMIA) and an optional, higher cap allowance with ex-ante approval would better meet the objectives and principles set out in the National Electricity Rules (NER). In particular, this approach would help balance divergent views about what is a reasonable level of allowance. Further details on this option, as well as comments on the options proposed by the AER, are provided in the next section.

Prior DMIA underspend

The AER has sought feedback on why DNSPs have under-utilised the DMIA in the past. In Ergon Energy's case, this has been due to:

- resourcing constraints
- the low value proposition of some internally proposed projects
- the DMIA criteria limiting the scope of projects that can be pursued
- funding not being available across regulatory control periods
- co-contributions from innovation partners, like universities, lowering DMIA costs.

[2] The plan is required to be submitted under clause 127C of the *Electricity Regulation 2006*. Refer to https://www.ergon.com.au/network/network-management/demand-management/demand-management-plans-and-reports.

Table of detailed comments

Question(s)	Ergon Energy response
Interpretation and proposed implementation of the new rules	
1. Do stakeholders support our interpretation and proposed implementation of the new rules? If you have alternative views, please share these and provide supporting evidence.	Ergon Energy generally supports the AER's interpretation and proposed implementation of the new rules, as well as the additional assessment criteria developed by the AER. In particular, we strongly agree that the new mechanisms should be transparent, simple to understand and administratively easy to apply. This will help facilitate greater market participation and lower the administrative burden for DNSPs. Having said this, we do not believe an additional assessment criteria relating to competition should be included. Other regulation is more appropriately placed to address this issue (e.g. ring-fencing). In developing the new mechanisms, we believe it is important to ensure the scope of eligible projects/options is interpreted as broadly as possible (providing they meet the respective objectives and criteria set out in the NER). For example, the innovation allowance should not be restricted to pure peak load management. While this continues to be an augmentation driver, it is unlikely to be the only driver in the future. Future risks include voltage stability, supporting renewable energy, enabling market transactions and peer to peer trading, disconnections and reliability, and distribution service operator models. Constraining the scope of the innovation allowance can limit the development of new opportunities in these areas.
Demand management incentives and the regulatory framework	
2. Do you agree with our view on the main demand management incentives (or disincentives) provided under the regulatory framework and the potential issues associated with these incentives? Please provide reasons to support any alternative	Ergon Energy agrees with the AER's views on the main demand management incentives provided under the regulatory framework. Our response on some of the potential issues associated with these incentives is provided below. <u>Incentives across opex and capex</u> Please refer to our response above regarding the totex approach.

Question(s)	Ergon Energy response

views you may have.	Service level incentives
	
	DNSPs cannot practically mitigate the risks associated with the non-delivery of demand management solutions in the manner suggested by the AER. This is because:
	
	• Based on our experience to date, increasing the customer penalty for non-performance decreases the customer's likelihood to participate in programs. If the penalties are too high many customers will not be interested in participating, as the reward is not big enough to outweigh the risk and warrant the effort and distraction from their business as usual activities. On the other hand, if the penalties are too low, customers do not receive the right incentive to perform, leading to inefficient outcomes.
	• DNSPs cannot self-insure or purchase insurance against the risk.
	    o There is no commercial market.
	    o It is not possible to calculate a robust self-insurance premium due to the lack of available data on commercial insurance premiums, the unpredictable nature of the performance of demand management solutions and uncertainty around the volume of demand management solutions that may be in place over the period.
	
	Importantly, the risks associated with an outage are not purely financial. There may be community and political considerations too.
	
	If the AER wishes to pursue changes to the STPIS, this should be consulted on as part of the AER's STPIS review.
	
	Current information requirements
	
	Ergon Energy's website provides a substantial proportion of the information stakeholders have identified as being useful to overcome barriers to demand side engagement. For example, our interactive incentives map[3] shows (down to the land boundary) where incentives are available and includes information on:

[3] https://www.ergon.com.au/network/manage-your-energy/incentives/search-incentives

Question(s)	Ergon Energy response
	• network assets • target demand • price caps for incentives • numbers of customers (residential and business) • the peak network risk time. We also maintain an interactive map[4] on system limitations/constrained feeders to meet our Distribution Annual Planning Report (DAPR) obligations, and engage with providers of demand management solutions through our Trade Ally Network. It is important to note that, despite the availability of this information, the response from the market to uptake demand management incentives has been slow. At the time of writing, only one third of our current annual demand management program has been subscribed to. While this may be partially attributable to the newness of our delivery model (i.e. the mapping model), there is a risk that the low uptake to date has been commercially driven. This may be due to: • The complexity of the solution. If the options available to mitigate the demand are complex, then there would need to be a much greater return than usual to entice market interest. • Geographical factors (e.g. distance) and population density. Even if the $ per kVA incentive was attractive, the volume may not be sufficient enough to justify the distance and time. • Size or available margin to help solve the problem. Unsurprisingly, the market responds best when profitability is likely to be high. A solution delivered via a single contract for a targeted problem can usually achieve this goal. However, the market tends to struggle to develop a profitable solution when engagement with many small customers is required to address the constraint (e.g. a residential driven constraint). This is exacerbated in Ergon Energy's network due to its radial and regional nature. We have

[4] https://www.ergon.com.au/network/network-management/future-investment/distribution-annual-planning-report/dapr-map

Question(s)	Ergon Energy response
	small constraints and, consequently, small value streams for the market. Because of this (and the low population density), we have achieved more response from local electricians than large aggregators or wholesalers. <u>Cost reflective price signals</u> Ergon Energy agrees with the AER's comments that the move towards cost reflective pricing will be gradual. However, contrary to the AER, we strongly believe this presents a case for using cost reflective pricing as a demand management product. In a non-cost reflective environment, a demand management product must first work to offset the tariffs which are working against an efficient outcome before it can address the constraint. For example, the cost of a demand management product to increase customers' power factors, and therefore release more network kVA capacity, is reduced when kVA tariffs are deployed. The kVA tariff creates the right foundation and demand management products can leverage this rather than having to create all of the incentive (which happens when a kW tariff is in place). Increasing the adoption of cost reflective prices in constrained parts of the network provides the optimal pricing foundation to facilitate lower cost demand management outcomes. As such, incentives should be provided to remove barriers and encourage their adoption. <u>Cultural and other non-market barriers</u> Ergon Energy agrees with the AER's comments in relation to the risks of setting targets to encourage demand management or other forms of non-network solutions. Please refer to our response to question 6 below.
Potential incentive scheme design options	
3. Do you see value in exploring the net-market benefit sharing mechanism further, despite the difficulties associated with measuring net-market benefits?	Ergon Energy agrees that market benefits are both difficult to measure and to apportion. We therefore see value in exploring a more simplified version of the net-market benefit sharing mechanism proposed in the Consultation Paper. A simplified version could include: • a $X per kVA incentive to reflect a share of upstream market benefits from demand

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If yes, what detail of guidance should we provide on calculating market-wide costs and benefits? Should we (and if so, how should we) establish a method for valuing smaller demand management projects in a way that reduces the administrative burden of applying the Scheme to these projects?	management • kVA and benefit calculation methods the same as those used for Regulatory Investment Test for Distribution (RIT-D) evaluations • recovery of the incentive through an adjustment factor in the revenue cap, following a secured commitment to reduce demand. We encourage the AER to explore options for a simplified version of the mechanism at its upcoming workshop and consult on this further via an exposure draft of the scheme.
4. Since the RIT-D already requires distributors to select the option with the highest total market benefit, should we (and if so, how should we) treat RIT-D projects differently under this type of Scheme (that is, under a net market benefit sharing mechanism)?	RIT-D projects should not be treated any differently under a net-market benefit sharing mechanism. Further, as noted above, any new mechanism should align with the RIT-D market benefit calculation and vice versa. We note that the RIT-D is a prescriptive and time consuming process that occurs late in the risk cycle, when the need and network solution is fully defined. This results in delays with engaging the market for non-network solutions as the DNSP needs to wait for the RIT-D process to be initiated before the opportunity can be put to the market. A more efficient solution may be to engage with potential providers without undertaking a RIT-D and developing solutions to mitigate the network issue in collaboration with market providers.
5. How might we best combine the mechanisms discussed in section 6 into an option that achieves the Scheme's objective? If you prefer a mechanism that we did not discuss in section 6, please provide details on this mechanism.	If the scheme includes a range of mechanisms, the AER will need to establish criteria governing when each mechanism will apply. This will ensure the process is transparent and will provide certainty to DNSPs and other stakeholders. The exclusion of the innovation allowance from the opex building block and EBSS can be combined with any of the mechanisms discussed. However, to avoid multiple financial incentives and stakeholder confusion, some of the other mechanisms should not be combined. For example, the uplift amount should not be combined with the net-market benefit sharing mechanism.
6. If you have views against applying any of the particular mechanisms discussed in section 6, please provide reasons to support	Ergon Energy does not support a number of the mechanisms proposed by the AER. Our reasons are detailed below.

Question(s)	Ergon Energy response
this view.	<u>Type 3: Mechanisms to promote competition</u> *Incentivise distributors to provide information* As noted above, the uptake of our demand management incentives under our new go to market mechanisms has been relatively slow, despite information being readily available to the market. We therefore do not believe there is merit in adopting this type of mechanism. *Bidding mechanism to encourage market delivery* Ergon Energy does not support a bidding mechanism. While a DNSP may be able to identify a constraint five to 10 years in advance and one possible option to solve the constraint, the DNSP is unlikely to contract a demand management solution at that time. This is because under a direct asset deferral methodology: • The final network solution will not be known until later in the risk cycle. This means the exact Net Present Value deferral or benefit is subject to variation. • The constraint may not eventuate due to a range of factors like changes in customer consumption, economic conditions and technologies (both demand side and network side). • If the network solution is subject to a RIT-D, the DNSP must apply the RIT-D process. This is unlikely to occur until the network solution is defined. Some of these issues have been the driving force behind Ergon Energy's development of the Optimal Incremental Pricing (OIP) methodology.[5] This methodology enables early engagement, defines the pricing and actively targets the risk that drives expenditure. As part of the bidding mechanism, the AER has also suggested that DNSPs could be provided an incentive to develop a standard form contract for demand management. Ergon Energy has already developed a range of 'standard contracts' to reduce the administrative burden of demand management. However, these contracts only work for standard demand management offerings (e.g. larger, known demand management such as

[5] https://www.ergon.com.au/network/network-management/demand-management/pricing-network-risk

Question(s)	Ergon Energy response
	demand response from embedded generators) and must still be altered to suit the individual sites and site capabilities. For smaller demand opportunities we have developed a 'deemed product' which has a much lower contractual, measurement and verification obligation. <u>Type 4: Targets for demand management deployment</u> Setting firm targets may result in inefficient outcomes, as it can create a situation where demand management is contracted to meet the target and not for the efficient operation of the network. This is inconsistent with the scheme's objective. Ergon Energy was previously subject to firm MVA targets as part of our jurisdictional Demand Management Plan. Ergon Energy formally sought approval for changes to the targets from the Queensland Department of Energy and Water Supply. Our MVA targets were replaced with efficiency targets ($X per kVA of delivered demand reduction) from 1 July 2016. With the implementation of our new OIP methodology the volume of demand is continually recalculated to manage network risks, creating a variable demand requirement. Our new demand management performance measures are based on the efficiency to deliver this variable demand requirement, rather than the total volume of delivered demand. Other issues associated with setting targets include: • The potential need to revise targets mid-period due to changes to economic outlooks, security planning criteria and localised load growth. These factors impact demand growth and the need to invest in either capital or demand management solutions. When growth is flat (as it is now), the immediate need to invest in demand management is reduced. It is not clear how the AER intends to manage this if targets are prescribed as part of the distribution determination process. • The target may be achieved, but the constraint may not be mitigated due to the operational cost of contracting the MWh being too high. For example, 4 MWh is required to effectively mitigate a 2 MVA peak demand event for two hours, but mitigating a 2 MVA peak demand event for four hours would require 8 MWh. This can substantially change the operational cost of demand management. • Practical difficulties in determining what reductions in demand are actually attributable to the demand management solutions.

Question(s)	Ergon Energy response
	• Administrative costs associated with setting targets, verifying the results and compliance reporting.
7. How we might best give effect to or enhance the information and reporting requirements discussed in section 6.5?	Ergon Energy notes the exact scope of the information and reporting requirements will depend on the mechanism adopted by the AER. We believe the following principles should be applied: • The information and reporting requirements should not be overly prescriptive or administratively burdensome. • There should be no duplication with other reporting requirements (e.g. Regulatory Information Notices (RINs), the DAPR and the new system limitations report under the Local Generation Network Credits rule change). • Confidential information should not be disclosed publicly.
Potential innovation allowance design options	
8. Which of the options discussed above in section 7 would best achieve the Allowance Mechanism's objective? Please provide reasons supporting your view. If you prefer an Allowance Mechanism design that we did not discuss as an option in section 7, please provide details on this option.	As noted above, Ergon Energy prefers an innovation allowance mechanism which is comprised of: 1. A modest innovation allowance, as per the current DMIA. 2. An optional, higher allowance cap with ex-ante approval for larger non-network R&D projects (e.g. full-scale trials of concepts that are successful under the modest innovation allowance). The modest innovation allowance would operate in the same manner as the current DMIA, with DNSPs proposing (and the AER approving) an amount as part of the distribution determination process. It would allow DNSPs to test, trial and develop non-network capabilities in a dynamic, small-scale environment. Any unspent funds would be returned to customers in the future through the annual pricing process. For larger projects, DNSPs could seek approval of the project and the required funding from the AER on an ad hoc basis via a pre-implementation plan. A summary of this plan could be published on the DNSP's or the AER's website and potentially be subject to stakeholder feedback. A clearly defined approval process would be required, including criteria on how the

Question(s)	Ergon Energy response
	AER will assess projects, the timeframe in which the AER is required to approve a project proposal (e.g. within 30 business days after receipt of the project plan) and how additional funding can be sought if required. Once approved by the AER, the funding could be recovered from customers in the forthcoming year's Pricing Proposal. For DNSPs subject to a revenue cap, this could be achieved through an incentive scheme adjustment factor (i.e. the amount would be added to the annual revenue requirement). As above, any unspent funds would be returned to customers in the future through the annual pricing process. In the event this alternative option is not implemented, Ergon Energy would support either Option 1 or Option 2. In applying the alternative option, Option 1 or Option 2, the following principles should apply: • Funding under the innovation allowance should be available to research organisations (e.g. universities and the CSIRO) and other market participants, at the DNSP's discretion. This provides third parties with an opportunity to compete for funding from the DNSP, while ensuring the project is addressing an issue that is affecting the DNSP and its network. • The innovation allowance should be flexible. Nominating projects as part of the distribution determination process restricts DNSPs' responsiveness to emerging issues and changes in the operating environment. Within the period, DNSPs should be able to alter the scope of the project to extract the maximum value or cease the project early if, for example, the required knowledge has been gained. Further consultation on or approval of these changes would delay the deployment of demand management solutions and create an overly complex administrative burden. • Projects commenced in one regulatory control period should be able to continue into the next period and maintain their funding. This would eliminate the risk of projects not being commenced at the end of a regulatory control period. Consideration will need to be given to how unspent funds are returned to customers in these instances (e.g. a project may not be completed in time for unspent funds to be returned to customers in the second year of the next regulatory control period, as is the case

Question(s)	Ergon Energy response
	under the current DMIA). • Tariff trials (for the avoidance of doubt) should be exempt from complying with the Tariff Structure Statement obligations set out in the NER.
9. If you have views against applying any of the particular mechanisms discussed in section 7, please provide reasons to support this view.	Ergon Energy does not support the bidding mechanisms proposed under Options 3 and 4. Any centrally managed process, bidding or otherwise, does not have the level of flexibility needed to deal with changing conditions. Even if it did, requiring a project to continually go back to a central administrator to change the scope is inefficient and will hinder innovation. It may also cause a situation where a project continues to completion even though it may be clear in the early stages that the project will not succeed. These options would also be costly to administer. Further, the involvement of third parties is already common practice under the current DMIA. It is therefore unclear what benefit the bidding process will provide. For example, Ergon Energy worked with the Queensland University of Technology, Smart Grid, LED Roadway Lighting Ltd and three host sites to validate the performance of light emitting diode (LED) technology for public lights. As a result of the project, LED public lights are now becoming a standard installation option. The bidding mechanism options also appear to limit a DNSP's involvement in the demand management supply chain. DNSP involvement is crucial to achieving successful innovation and applying it in business as usual activities. One such example is our innovative Grid Utility Support System (GUSS), which won the Excellence Award for Innovation, Research and Development at the 2016 Australian Engineering Excellence Awards for Queensland.[6] Each GUSS unit is an advanced, cost-effective technology solution that can reduce peak loads and support reliable voltage levels for up to 100 customers. Finally, we strongly believe it is unfair for customers to fund projects they are not directly benefiting from (as is the case under the aggregate funding model proposed by the AER). While we recognise that customers might indirectly benefit due to the publication of results,

[6] https://www.ergon.com.au/about-us/news-hub/talking-energy/technology/national-recognition-for-electricity-innovators

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	these results may not be transferrable to other networks due to differences in customer demographics and operating environments etc.
10. How we might best give effect to or enhance the information and reporting requirements discussed in section 7.5?	Ergon Energy considers the following principles should apply to the information and reporting requirements: • They should be scaled to the size or complexity of the projects being funded. The administrative burden should not be so high that it prevents a project from being pursued, stifling innovation in the process. In particular, pre-project implementation plans should not be required for small-scale projects and outcome reports should be limited in length. • They should not be overly prescriptive. • There should be no duplication with other reporting requirements (e.g. RINs). • Confidential information should not be disclosed publicly. To assist with knowledge sharing, Ergon Energy suggests that the outcomes of trials could be included in a central, online repository managed by an independent or industry body.