31 August 2009

An Innovation Funding Scheme for Network Businesses

A Report for the Australian Energy Market Commission

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1. Introduction

NERA Economic Consulting (NERA) has been asked by the Australian Energy Market Commission (the Commission) to consider whether a separate innovation funding scheme is required for network businesses and, if so, what design options should be considered.

This request has arisen from the Commission's consideration of the regulatory framework in light of climate change policies and specifically whether network businesses have sufficient incentives to undertake complex and potentially uncertain research and development to meet expected network operation challenges and facilitate demand-side participation in the market. This study will assist the Commission to decide whether a separate innovation funding scheme is warranted.

1.1. Background and context

The Commission is currently undertaking a review of energy market frameworks in light of climate change policies (the climate change review), which was requested by the Ministerial Council on Energy (MCE).[1] The review is investigating whether changes to the existing regulatory arrangements are necessary in order to facilitate the outcomes desired from government policies to address climate change. These policies include the introduction of the carbon pollution reduction scheme (CPRS), and the expansion of the renewable energy target (RET).

The 2nd Interim Report of the Commission for the climate change review sets out its draft recommendations, being to:

- increase the flexibility for regulated retail pricing;
- facilitate network investment of sufficient capacity to provide transfer capabilities to remote renewable generation;
- introduce transmission charges to generators to improve the signals for generation location decisions; and
- provide distributors with temporary funding to support innovation and so allow them to respond to the challenges associated with larger numbers of connected generation and more variable network flows.

Similar concerns about the lack of incentives for network businesses to undertake research and development have been identified in the United Kingdom by the Office of Gas and Electricity Markets (Ofgem) and also by Australian regulators, particularly the incentives to invest in demand management to address congestion as compared to network options. This has led to the development of a number of schemes to provide a more targeted incentive for network businesses to undertake research on how best to integrate demand side participation and more distributed and intermittent generation into network operations.

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1 AEMC, (2009), *Review of Energy Market Frameworks in light of Climate Change Policies: 2nd Interim Report*, June, Sydney.

1.2. The study and structure of the paper

Our approach to this study has involved setting out the principles underpinning the incentives within the existing regulatory framework for network businesses to undertake research and development that facilitates and improves network operation. This discussion defines the nature of the incentive problem as the context for considering innovation funding scheme design options, drawing upon programmes developed in both Australia and elsewhere.

The critical questions that we have considered in this paper are:

- Is there an incentive problem within the existing regulatory arrangements that impedes network businesses from undertaking research and development?
- How material in practice is the incentive problem? and
- What are the possible scheme design options?

The remainder of this paper sets out our consideration of these questions in detail and is structured as follows:

- Chapter 2 describes the lack of incentives for network businesses to undertake innovative research and development as part of the existing regulatory arrangements;
- Chapter 3 briefly summarises the results of our examination of research and development funding schemes within Australia and selected other countries;
- Chapter 4 sets out the possible design options for a research and development funding scheme; and
- Chapter 5 provides our conclusions and sets out our recommendations.

2. The innovation incentive problem

In the absence of competition distributors have incentives to operate and invest in networks as provided through the regulatory framework. These incentives result from the interaction of regulatory obligations, service standards and the process of determining network revenue requirements, all of which combine to ensure that distributors seek to deliver desired network services in an efficient manner.

That said, the incentives inherent in the regulatory framework are not perfect, and so in this chapter we consider whether those incentives are sufficient for distributors to undertake network research and development to accommodate expected changes in the use of the network. The expected changes result from an anticipated increase in the number, and decrease in the average size, of generation units connected to the network and an associated increase in the variability of network flows resulting from more intermittent renewable generation. In addition, greater use of demand-side participation is also likely to become an increasingly cost effective option to delay network and/or generation investments.

This chapter briefly describes the expected challenges facing distributors following the introduction of the CPRS and the expanded RET. Next the incentives within the existing regulatory framework for network businesses to undertake research and development are considered. We conclude by setting out the circumstances where additional research and development is expected to be required.

2.1. Challenges facing distributors and the need for innovation

The Commission has examined the implications of the CPRS and expanded RET for the energy market, and has identified four anticipated market challenges, namely:[2]

- changes to the fuel mix and location of generation;
- expansion of renewable generation investment, with the associated challenges for the operation of the network associated with increased variability of network flows;
- the need for new network capacity to accommodate the changing geographic location of generation within the network; and
- to accommodate increased numbers of distributed generation within the operation of the network.

The implications for distributors of these anticipated changes to the structure and operation of the energy market are most likely to be related to:

- accommodating increasing distributed generation within the operation of the network, some of which might be intermittent; and
- increased benefits from facilitating demand-side participation as an alternative to new network capacity investments.

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2 AEMC, (2009), *Review of Energy Market Frameworks in light of Climate Change Policies: 2nd Interim Report*, June, Sydney.

Intermittent generation sources rely on uncontrollable fuels such as wind and solar. The expected increase in this type of generation arises out of the expanded RET under which retailers are obligated to source a certain proportion of electricity from renewable sources. Providers of renewable sources are issued credits for each unit of renewable electricity generated. These credits can then be sold to retailers, and so provide an incentive to purchase renewable generation sources some of which can be established on personal properties (eg, small wind and solar).

Distributors play an important role in distributed generation through the power in the regulatory framework to place obligations on connecting generators (or indeed allow the distributor to refuse network connection) to ensure that a generation connection does not adversely affect the local operation of the network[3]. For example, if a distributor believes that a proposed connecting generator does not have the capability to withstand operational difficulties in the network, which could result in a black out, the distributor can refuse to connect the generator.

The approach allows the distributor to manage network security and reliability, but can also lead to inefficiencies in circumstances where uncertainty about the impact of a new type of generation on the network results in overly cautious obligations being imposed on a connecting generator by a distributor. This can increase the cost of connection for these new types of generation and potentially make otherwise viable distributed generation, unviable. Therefore, as new types of distributed generation seek connection to the network, it is anticipated that research and development will be needed to ensure that these generators can be cost effectively connected without compromising network security and reliability.

In addition, increasing wholesale prices as a consequence of pricing carbon emissions through the introduction of the CPRS will mean that demand side options will become an increasingly financially viable alternative to network investments. This is because the payoff for households participating in such schemes will likely increase (because of the avoidance of both electricity charges which are presumed to be higher, and payments for participation in such schemes). All other things being equal, demand-side participation can be expected to increase as a consequence of the introduction of the CPRS.[4]

However, distributors are generally wary of demand-side alternatives to network investments because, they claim, such alternatives are less reliable as compared to network investments. As such and in light of distributor network reliability obligations often demand-side alternative options can be discounted or dismissed despite possibly being a more cost effective option. This highlights the need for research and development to improve distributor's understanding of its value. Decreasing the uncertainty associated with demand side participation in the market will therefore assist in achieving Australia's emission reduction goals by reducing electricity consumption and avoiding additional network investment, with distributors likely to play an important research and development role in achieving these decreases.

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[3] AEMC (2009), *National Electricity Rules*, Chapter 5, Version 30, Clause 5.3.4 (e), Sydney.

[4] The Commission has been investigating whether there are material barriers to the efficient and effective use of demand-side participation in the NEM, see AEMC, (2009), *Review of Demand-Side Participation in the National Electricity Market – Stage 2: Draft Report*, 29 April, Sydney.

In summary, distributors will play an important role in facilitating the introduction of distributed generation and renewable generation in response to the introduction of the CPRS and the expanded RET, by developing cost effective solutions to manage the connection of these new generators to the network. As such distributors will need to consider how to best manage a more varied and larger number of smaller generators dispersed through the network, with potentially greater network flow variability.

Further, distributors have an opportunity to play a key role in the investigation and development of demand-side participation alternatives to network investment. Creating incentives for distributors to do so will be an important part of managing the challenges arising from the introduction of the CPRS and the expanded RET. The challenge for distributors will be to facilitate these changes in the most cost effective manner without creating unnecessary impediments. Such fundamental changes in the operation of the network will therefore likely require a re-examination of the processes and procedures used to operate the network, which in turn will likely require distributors to invest in research and development.[5]

2.2. Incentives of distributors to invest in research and development

In principle, investment in research and development or innovation should be undertaken up to the point where the expected return from the investment is equal to the cost of the investment. The expected return to a research and development investment can be thought of as a combination of the return to the investment if the anticipated outcomes of the investment are realised weighted by the likelihood that those outcomes will be realised.

When the likelihood of the outcomes being realised is small, or in other words the investment is ‘speculative’, the risk of any specific research and development project not delivering benefits is high. Diversification in research and development projects allows an investor to balance these risks as part of a research and development investment portfolio. Indeed, this is the approach used in industries that involve significant amounts of research and development, eg, the pharmaceutical drugs industry. Where there is little scope for diversification (eg, where research is being undertaken directly by a business engaged solely in a particular industry), the associated expected rewards from the project must outweigh the costs despite the associated uncertainty and risk.

For industries facing competitive pressures, research and development can be critical to maintaining market share by lowering costs or through product innovation.[6] For distributors where there is no such competitive pressure, the regulatory framework must compensate for the lack of competitive incentives to undertake research and development and so seek cost efficiencies over time. The existing regulatory framework encourages these efficiencies by:

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[5] While research and development can be undertaken by third party specialist research providers, there are likely to be a need for research testing through pilots and trials. Distributors will therefore eventually be needed as part of the development of any new innovation.

[6] In some industries, third parties undertake research and development and subsequently sell innovations back to participants in the industry. In this way a separate market for innovation or research and development can develop to manage the uncertainties and risks associated with research and development.

- providing an overarching incentive to seek out cost efficiencies by decoupling revenue earned by a distributor from its costs over a regulatory period;
- placing obligations on distributors to satisfy service requirements and operate the network safely;
- requiring distributors to take account of demand side alternative options when assessing proposed network investments; and
- allowing distributors to manage connections to the network, and where necessary impose requirements on connecting generation or load to facilitate connection while satisfying network operational needs.

We describe the implications of each of these regulatory arrangements for the incentives of distributors to undertake research and development below.

2.2.1. Incentives for cost efficiency

The fundamental purpose of the current regulatory pricing arrangements for distributors as set out in chapter 6 of the National Electricity Rules is to provide incentives for cost efficiency, and so promote the National Electricity Objective.[7] These cost efficiency incentives are created mainly by decoupling revenue requirements determined via a regulatory price reset, from the subsequent costs incurred by the businesses during the regulatory period. A business that achieves higher cost efficiencies than anticipated during the price reset will then earn a higher rate of return on capital employed than approved by the regulator over the regulatory period. Similarly if a business does not achieve cost efficiencies then it will earn a lower rate of return.

Importantly, the incentive for cost efficiency within the regulatory framework arises from the decoupling of revenues and costs during *a regulatory period.* In circumstances where cost efficiencies have been achieved, the firm can retain the additional profits until the next price reset, at which time those efficiencies are passed through to consumers in the form of lower revenue requirements.[8] In this way, the benefits of cost efficiencies are shared between the distributor and consumers.

These arrangements in combination with a commercial incentive to maximise shareholder value ensure that distributors have a financial incentive to seek out all available cost efficiencies within a regulatory period. These efficiencies can take the form of finding lower cost materials, or improving business processes to deliver the same level of service at overall lower cost.

In addition to this basic cost efficiency incentive, the regulatory framework provides a number of other mechanisms to ensure that businesses seek out cost savings without distorting the timing of investment and cost saving decisions. These include:

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7 Section 7, National Electricity Law.

8 The efficiency carryover mechanism provides for the benefits of capital cost efficiencies to be extended into subsequent regulatory periods to remove incentives within the regulatory framework to achieve cost efficiencies during the first year of a regulatory control period. However, following the outworking of this scheme, any associated cost efficiencies that have been achieved are passed through to consumers through lower revenue requirements.

- the inclusion of an efficiency carryover mechanism, where the benefits of cost savings achieved during each year of one regulatory period are extended into the subsequent period to minimise any possible distortions in the timing of cost savings during a regulatory period (namely, adopting cost saving measures at the beginning of the regulatory period and revealing higher costs for the year under review at the end of the period to achieve higher than necessary costs in the subsequent period);
- requirements to undertake an economic cost benefit assessment for large capital projects, with an explicit requirement to consider non-network alternative investments that might be more cost effective at alleviating a network constraint problem; and
- the definition of capital and operating expenditure tests that must be satisfied prior to its inclusion in the regulatory revenue allowance.

In summary the existing regulatory arrangements seek to provide a strong incentive for distributors to seek out all available cost savings. On face value this would suggest that they would in turn create incentives for distributors to undertake research and development investments that are expected to lead to further cost savings. However, in practice the arrangements are likely to create a disincentive to undertake research and development because:

- the speculative nature of some research and development might not satisfy the capital expenditure tests of the regulator;
- many innovation projects are likely to have payback periods that extend across regulatory periods and the regulatory framework does not allow the firm to keep those benefits in order to justify the initial investment; andcost efficiency benefits are ultimately passed onto customers in the form of lower prices, and so distributors may be reluctant to invest in research and development if the benefit stream is not sufficient to justify the initial outlay.

In our opinion this highlights how the existing regulatory arrangements might result in less than optimal investment in research and development that leads to overall cost savings unless those savings are achieved within the same regulatory period. However, this disincentive to undertake research and development needs to be examined taking into account the incentives placed on the business to meet its service standards and obligations.

2.2.2. Service standards and obligations

The regulatory arrangements require distributors to provide network services at a standard that satisfies the reliability requirement.[9] This requirement is the principal driver of network investments, and in combination with the service incentive scheme, ensures that the network is operated in a manner that is both safe and reliable.

To ensure that network services continue to meet these standards, distributors conduct an annual planning exercise whereby network constraints, demand and supply are forecast into the future and so the need for network investments are identified.[10] Following the

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[9] AEMC Reliability Panel, (2007), *NEM Reliability Standard – Generation and Bulk Supply*, December 2007.

[10] This annual planning exercise is conducted in accordance with the requirements set out in Rule 5.6.2.

introduction of the CPRS and the expanded RET, any changes to the number of generators and network flow variability will be factored into the businesses network planning arrangements. This means that (at least in principle) any network investments required as a consequence of these changes will be incorporated into subsequent capital and operating expenditure requirements for the distributor.

This approach relies on the existing network planning arrangements to be capable of meeting the challenges associated with the anticipated changes. Network planning arrangements have undergone considerable review in recent years, including by the Commission who was asked to review national transmission planning arrangements by the Ministerial Council on Energy.[11] The Commission acknowledged the importance of the proposed national transmission network development plan taking into account the interrelationships between transmission, generation, distribution and non-network options to deliver reliable energy supply at efficient costs.[12] While the review made recommendations (which have since been implemented) to revise the regulatory test as applied to proposed transmission investments, the existing regulatory test for distribution network investments was retained.

The network planning obligations in combination with the application of the regulatory test to proposed distribution network investments is therefore likely to ensure that any network investments required as a consequence of future network flow changes will be identified and addressed. That said whether the distributors do so at least cost will be guided by the incentives for cost efficiency as described above. This suggests that the current regulatory arrangements might not deliver these new connections at the least possible cost, absent the research and development that might be necessary for cost savings to be achieved.

2.2.3. Incentives to consider demand-side participation

Demand side alternatives to network investments has been identified as an area where distributors have potentially little incentive to investigate, in part because of the uncertainty about the reliability of the demand savings. In addition, it has been previously argued that the potential for distributors to forgo revenue as demand decreases also creates a disincentive for networks to invest efficiently in demand side options.[13]

The Commission has previously considered this potential incentive problem as part of its review into demand side participation in the National Electricity Market.[14] While acknowledging that the uncertainty about reliability potentially warrants the introduction of some scheme to encourage innovation,[15] it also demonstrates that network businesses have sufficient incentives to invest optimally in demand side participation, irrespective of the lost revenue. Indeed, the Commission demonstrates that it is socially optimal to invest in demand

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11 AEMC, (2008), *National Transmission Planning Arrangements - Final report to the MCE*, 30 June.

12 Ibid, page 11.

13 IPART, (2004), *NSW Electricity Distribution Pricing 2004/05 to 2008/09 - Final Report*, June 2004. p. 97.

14 AEMC, (2009), *Review of Demand-Side Participation in the National Electricity Market*, Stage 2: Draft Report, 29 April, Sydney.

15 Ibid, pages 27-29.

side options up to the point where the cost of the demand side option plus foregone network revenue is equal to the benefits associated with avoided network costs.[16]

That said, distributors often claim that there remains considerable uncertainty about the reliability of demand side alternatives to network investments, which can create risks for a distributor as it seeks to satisfy its reliability obligations. The risks are said to arise from a potential for demand-side options to not be available when needed, due in part because of a reliance on consumer action.

There are a number of ways that distributors might seek to manage these risks. These include through:

- contractual obligations with third party demand-side providers; and/or
- providing a mix of controllable and behavioural demand-side options within a demand management portfolio.

Regardless of how such risks can be managed, improving the understanding of distributors about the risks associated with demand-side options will improve the likelihood that they will be evaluated correctly when compared with network options. Removing any impediments to distributors to undertake research and development into demand side options will help them to understand the risks and so minimise the opportunity for these risks to be overstated leading to less than optimal investment in demand side options. This suggests there may be benefits from undertaking research and development to understand how demand side options can be best used to lower the cost of providing electricity networks.

In our opinion therefore, the existing regulatory arrangements do not create sufficient incentives for distributors to invest optimally in research and development to support the development of demand side alternatives to network investments.

2.2.4. Managing distribution network connections

The final element of the regulatory framework relevant to our consideration of the incentives for research and development relates to the approval of network connections by distributors. In our opinion, this is the area where there could be significant problems following an anticipated increase in the number of distributed generators seeking connection.

Chapter 5 of the *National Electricity Rules* provide the framework for connection to a distribution network, and so access to the national grid.[17] The Rules specify the technical requirements that connection agreements must include to ensure standards of performance are at or above the minimum access standards[18] otherwise negotiations are necessary under clause 5.3.4 (e).[19] Distributors are required to reject an applicants' proposed negotiated access standards if it does not meet the technical requirements, or if it would adversely affect

[16] Ibid, pages 17-20 and appendix C.

[17] AEMC, (2009), *National Electricity Rules – Chapter 5*, Version 30.

[18] These standards are set out in schedules 5.1, 5.2, 5.3, 5.3a and 5.1a.

[19] AEMC, (2009), *National Electricity Rules – Chapter 5*, Version 30, Clause 5.3.4 (e).

power system security and the quality of supply to other network users.[20] In practice there is considerable discretion provided to a distributor in its interpretation of the technical requirements set out in the rules.

As discussed in section 2.1, this means that distributors have the potential to block a proposed connection to the network, or alternatively impose costly obligations on connecting generators, to ensure that network reliability and safety is maintained. These powers reflect the importance of maintaining network reliability and safety in the supply of electricity to end-use customers.

That said, by having a strong incentive for distributors to focus on network reliability and safety there is no mechanism for distributors to seek out the most cost effective way of facilitating connection to the network at a particular location. This is because the cost of any connection requirements are borne by the connecting generator and so are not incurred by the distributor. This creates an incentive for distributors to require connecting generators to make investments to minimise any network operational risks, regardless of the costs associated with doing so. In effect there is no scope to balance the likelihood of risks against the cost of any additional connection requirements.

For most well known generation technologies, the connection requirements are well understood by all parties. However, for new and emerging generation technologies there is greater uncertainty such that a distributor might impose obligations in part because of its lack of understanding about the implications to the network of allowing a new type of generator to connect to the network. Indeed, it is possible that a distributor will be conservative in the imposition of connection requirements given the potential uncertainty for operation of the network for connection of a large number of distributed generators some of which might be intermittent.

This suggests that there is likely to be an incentive problem for distributors to undertake necessary research and development to facilitate connection of distributed generation through better understanding and management of the risks involved, given the incentive it has to maintain system safety and reliability.

2.2.5. Summary

In summary, the regulatory framework provides some incentive for investment in innovation to the extent it is linked to obligations associated with the operation of the network or returns within the same regulatory period.[21] That said, given that the benefits of research and development will likely extend beyond a regulatory period and that there is little incentive for distributors to seek out cost efficiencies for connection obligations, there is an 'in principle' incentive problem with the existing arrangements. This incentive problem is discussed in more detail along with possible design options of an innovation funding scheme in chapter 4.

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[20] Ibid. Rule 5.3.4A

[21] In addition, distributors will likely have access to other government funding sources for innovation associated with responding to the challenges of the CPRS and expanded RET. We discuss this further in section 3.1.2.

2.3. The nature of the innovation required

There are two principal areas where the existing regulatory arrangements might not provide sufficient incentives for research and development, namely:

- to support increasing demand side participation in the market, as an alternative to network investments; and
- to support an increasing number of distributed generation connections, some of which are likely to be intermittent.

For demand side participation, the problem relates to the uncertainties associated with the firmness of demand responses and so to what extent they can be relied upon to defer otherwise needed network investments. Similarly, for distributed generation the uncertainties relate to the interactions between multiple small generation units on the variability of network flows. The ultimate risk for distributors in both of these circumstances is a compromise in safety and reliability of the network, and so they tend to be fairly conservative and risk adverse. This can come at the expense of lost opportunities for cost savings.

The types of research and development that are therefore in question include:

- projects that seek to better quantify and understand the reliability of demand side measures, including (amongst others): pilots of smart metering technologies; time-of-use and other innovative pricing trials; direct load control programmes; and energy efficiency programmes;
- projects that seek to understand the impact of intermittent generation on the variability of network flows; and
- projects that develop technological options for particular types of distributed generation, to improve understanding of the impact of connecting these generators for the network security and reliability and possibly to develop lower cost ways of overcoming problems.

In summary, the types of research and development that are involved have the potential to deliver cost savings either to the connection applicant in the case of distributed generation projects, or to distributors and network customers where demand side participation leads to lower overall network costs. In both circumstances, the existing regulatory arrangements are unlikely to provide sufficient incentives for distributors to undertake research and development in these areas and so achieve these cost savings mainly because it would not retain the benefits from such research. This suggests that there might be some merit in providing a targeted incentive for distributors to invest in research and development in these two areas, at least in principle. We consider whether such a scheme should be implemented in chapter 4.

2.4. Summary

In summary, there are likely to be insufficient incentives in principle within the existing regulatory arrangements for distributors to invest in research and development that:

- supports improved understanding of the reliability and use of demand side participation in the management of the network; and

- supports the development of options for lowering the cost of connection of distributed generation.

To the extent that this lack of incentive is believed to be material, this suggests that there may be merit in considering the introduction of a scheme to address this incentive problem. We consider this further below.

3. Australian and international innovation funding schemes

In recent years a number of countries including Australia have provided specific incentives to encourage network businesses to fund research and development. Below we review the initiatives in Australia to assess whether supplementary programmes are required.

In addition we review initiatives introduced in the United Kingdom and United States of America, which have also provided specific incentives to network businesses for research and development. As in Australia, the focus to date has been in areas where there might be public benefits from an activity but where the associated risks and uncertainties mean that network businesses are unlikely to engage in the activity (ie, demand-side alternatives to network augmentation).

3.1. Australian innovation funding schemes

New South Wales was the first Australian jurisdiction to recognise the need for, and then implement, a dedicated mechanism to fund research and development –the so called 'D-factor' scheme. The D-factor scheme aims to provide distribution network service providers (DNSPs) with an incentive to undertake demand management by allowing the DNSP to increase prices if demand management above a specified target is achieved. Almost all other jurisdictions in the NEM have since adopted, or are planning to adopt, similar schemes. This section describes those approaches established by the jurisdiction specific regulators and those that have been introduced by the Australian Energy Regulator (AER) since it has taken responsibility for DNSP price regulation.

3.1.1. Schemes introduced by jurisdictional regulators

In 2002 the Independent Pricing and Regulatory Tribunal (IPART) conducted an inquiry into the role of demand management. From this review IPART identified demand management options (eg, time-of-use tariffs and incentive payments to curtail load) as a more cost-effective way of relieving network constraints compared with network augmentation (eg, building additional lines and stations). This improves use of existing capital and so provides benefits to end users by lowering costs.[22] That said, IPART recognised that DNSPs faced a number of barriers to the use of demand management, including network pricing limitations under the regulatory framework, and consequently have undertaken few demand management activities.[23]

A key component of IPART's NSW electricity distribution pricing report for the 2004/05 to 2008/09 regulatory period was the introduction of a number of incentives to promote network demand management:[24]

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[22] IPART, (2002), *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services - Interim Report*, April 2002.

[23] IPART, (2004), *NSW Electricity Distribution Pricing 2004/05 to 2008/09 - Final Report*, June 2004.

[24] Ibid. p. 89.

> 'In determining the new regulatory framework for 2004–09, the Tribunal has aimed to ensure that these regulatory barriers are removed, and to neutralise the potential disincentive for demand management created by the change to a weighted average price cap form of regulation (which links revenue to volumes sold).'

As part of this new regulatory framework for NSW a 'D-factor' was introduced to the weighted average price cap formula for the recovery of demand management costs and foregone revenue.[25] Specifically, the D-factor allows DNSPs to recover:[26]

- approved non-tariff-based demand management implementation costs, up to a maximum value equivalent to the expected avoided distribution costs;
- approved tariff-based demand management implementation costs; and
- approved revenue foregone as a result of non-tariff-based demand management activities.

The introduction of the D-factor arrangement was supplemented by a set of specific guidelines to be used when quantifying the 'approved' costs and benefits of demand management measures outlined above.[27]

The operation of the D-factor provides for an increase in the allowable annual price adjustment if a DNSP meets or exceeds their demand management targets.[28] Accordingly, if a DNSP does not meet their level of demand management expenditure between years then it will receive a negative D-factor, which reduces the size of the allowed price increase in the relevant year. The D-factor allows for demand management costs and foregone revenue to filter through to prices after a two-year lag and will be carried forward at the DNSP's allowed rate of return.[29]

However, IPART intended that the D-factor scheme was established as a transitory measure:[30]

> 'IPART saw the D-factor as a short term incentive for businesses to overcome barriers to the greater use of demand management solutions in supplying network services, particularly with the introduction of the WAPC, and to support the emergent market for these solutions…. IPART expected that demand management, and its related costs, would become part of standard business practices of distributors so that, in the medium term, a special D-factor incentive would be no longer necessary.'

In Victoria, the Essential Services Commission (ESC) considered the introduction of a D-factor scheme in its 2005 Electricity Distribution Price Review (2006 - 10).[31] The review

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25 IPART, (2004), *Treatment of Demand Management in the Regulatory Framework for Electricity Distribution Pricing 204/05 to 2008/09 - Draft Decision*, February 2004.

26 IPART, (2004), *NSW Electricity Distribution Pricing 2004/05 to 2008/09 - Final Report*, June 2004.

27 These guidelines are the '*Guideline - Calculation of avoided distribution costs'* and the '*Guideline - Methodology for estimating foregone revenue'* published by IPART on 28 and 29 April 2005 respectively.

28 IPART, (2008), *Demand management in the 2004 distribution review: progress to date*, NSW Electricity Information Paper No 3/2008, 1 August 2008.

29 IPART, (2004), *NSW Electricity Distribution Pricing 2004/05 to 2008/09 - Final Report*, June 2004.

30 IPART, (2008), *Demand management in the 2004 distribution review: progress to date*, NSW Electricity Information Paper No 3/2008, 1 August 2008. p. 2.

examined whether there were any impediments to distributors implementing a least cost solution to network augmentation in the regulatory framework. The ESC did not consider that the introduction of a D-factor scheme was appropriate at the time of the determination.[32] In addition to the costs of administering the scheme the ESC stated that distribution tariffs can provide more efficient cost signals to customers and that this will be considerably enhanced through the interval metering rollout (IMRO). Specifically:[33]

> 'The Commission considers that before customers are required to fund additional high powered incentives for demand management, they should receive improved signals on the cost of their current network usage so as to be best informed of how their demand side response can reduce costs both to them as customers, and to the distributors.'

However, the ESC further noted that:[34]

> 'As the IPART D-factor was only implemented in its final determination made in 2004, it is premature to assess its effectiveness. The Commission will therefore monitor the success that this high powered incentive has on moderating increases in peak demand, in conjunction with monitoring the impact of the interval meter rollout on growth in peak demand.'

Although the ESC did not consider it necessary to introduce a D-factor scheme it found that there are disincentives for DNSPs to implement demand management initiatives, instead opting for network augmentation solutions to network constraints.[35] The regulatory arrangements in Victoria ensure that any benefits resulting from capital expenditure deferred due to demand management practices within a regulatory period are retained in full by the DNSP. However, where capital expenditure deferral benefits extend across regulatory periods[36] the benefits to the DNSPs are reduced and the benefits may be returned to customers following a subsequent price determination.

In light of this incentive problem, the 2006 determination provided a specific allowance of $600,000 for each distributor to fund trials of demand management initiatives.[37] In addition, the ESC excluded embedded generation or other demand initiatives from the service incentive, or 'S-factor' scheme.[38] This was to prevent DNSPs from being penalised if demand side responses and distributed generation was not be available during peak times, thereby affecting a DNSP's service performance.

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31 ESC, (2006), *Electricity Distribution Price Review 2006-10 October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006 - Final Decision Volume 1 - Statement of Purpose and Reasons*, October 2006.

32 ESC, (2006), *Electricity Distribution Price Review 2006-10 October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006 - Final Decision Volume 1 - Statement of Purpose and Reasons*, October 2006. p. 500.

33 Ibid. p. 500.

34 Ibid. p. 500.

35 ESC, (2006), *Electricity Distribution Price Review 2006-10 October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006 - Final Decision Volume 1 - Statement of Purpose and Reasons*, October 2006. pp 495 - 496.

36 For example where demand management, and the associated cost, takes place in one regulatory period but the deferred capital expenditure is expected to occur in subsequent regulatory periods.

37 Ibid. p. 496.

38 Ibid. p. 498.

Similarly in the South Australian Electricity Distribution Price Review for 2005–10, the Essential Services Commission of South Australia (ESCOSA) provided an allowance to ETSA Utilities to undertake a range of pilot demand management initiatives. ESCOSA made an allowance for expenditure of up to $20 million during the regulatory period in operating expenditure.[39] The funding of these demand management initiatives was seen as a test of their appropriateness to help determine the worthiness of funding future demand management implementation:[40]

> 'These trials, and the experience gained, will be used by the Commission [ESCOSA] and ETSA Utilities to determine the benefits and costs for wider application….It is the intention of the Commission to conduct a public review of the outcomes of this program of demand management initiatives in the final year of the 2005-2010 regulatory period, ahead of any consideration of ongoing funding. If some of the trials result in significant benefits to SA customers, the Commission will consider expanding such trials during the 2010-2015 regulatory period.'

3.1.2. Schemes introduced by the Australian Energy Regulator

The AER became responsible for the regulation of distribution networks in the NEM on 1 January 2008. In November 2008, the AER published its first electricity distribution decision, which was the draft decision for the NSW and ACT DNSP for the 2009–14 regulatory control period. Part of this included a demand management innovation allowance (DMIA) scheme to apply to all DNSPs[41] for the regulatory control period 1 July 2009 to 30 June 2014. The purpose of the scheme is:[42]

> '… to provide incentives for DNSPs to conduct research and investigation into innovative techniques for managing demand so that, in the future, demand management projects may be increasingly identified as viable alternatives to network augmentation.'

The DMIA is divided into two parts: [43]

- Part A provides DNSPs with an annual ex ante allowance,[44] which is broadly proportionate to the DNSP's average annual revenue requirement in the form of a fixed amount at the commencement of each year within the 2009-14 regulatory control period. Once the results from the regulatory period are known,[45] a single adjustment will be made to return the amount of any underspend or unapproved amounts to customers. This ensures the scheme is neutral in terms of the expenditure profile within the period to which it has applied. The AER published a set of criteria that any non-tariff demand management project or program must satisfy to qualify under this scheme.

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39 ESCOSA, (2005), 2005 - 2010 Electricity Distribution Price Determination Part A – Statement of Reasons, April 2005. pp. 53 and 60.

40 Ibid. p. 59.

41 Prior to this there were no demand management incentive schemes operating in the ACT.

42 AER, (2008), *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations*, November 2008. p. 3.

43 AER, (2008), *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations*, November 2008.

44 In addition, an annual ex-post review of expenditure under the scheme is conducted by the AER to ensure compliance with the DMIA criteria.

45 This is defined as occurring in the second year of the subsequent regulatory control period.

- Part B allows for the recovery of foregone revenue associated with implementing non-tariff demand management programs approved under part A of the DMIA. This applies to DNSPs whose services are subject to a form of control at least partially dependent on energy sold, such as a weighted average price cap or average revenue cap. The recoverable revenue under Part B does not have a specified cap, rather the amount available to be recovered is limited to approved revenue forgone resulting from a successful project established under Part A of the scheme.

As part of the DMIA, the AER decided to exclude any demand management costs from the efficiency benefit sharing scheme (EBSS).[46] The EBSS is a form of efficiency carryover whereby businesses are given incentives to pursue cost efficiencies and over time pass on these benefits to consumers through lower prices. The reason for excluding any demand management related costs from the EBSS is that the incentives that motivate businesses to pursue operating cost efficiencies under the EBSS are different to those under demand management programmes where operating costs are often required to increase to reduce capital spending.

The DMIA scheme was also not specified as a permanent measure and was introduced, in part, as a trial to analyse the costs and benefits of demand management and associated incentive schemes.[47] The AER stated its intentions for the DMIA scheme as:[48]

> ‘The operation of this scheme will be considered by the AER throughout the regulatory control period 2009–14, and an assessment of the scheme will be made when considering the AER’s application of demand management incentive schemes for the regulatory control period 2014–19.’

In addition to introducing the DMIA, the AER kept the D-factor arrangements IPART established in operation for NSW as part of the 2009 distribution determinations. A D-factor scheme was thought inappropriate for the ACT given differences between the two jurisdictions, namely the form of regulation (average revenue cap); network characteristics (the network in the ACT is characterised by many residential customers and few commercial loads); and stakeholder views that ActewAGL has scope to provide efficient pricing structures.[49]

The AER has also introduced demand management initiatives in the other NEM jurisdictions in preparation for their pricing reviews. In October 2008, the AER published a demand management incentive scheme (DMIS) to apply to DNSPs in Queensland and South Australia for the 2010-15 regulatory control period. Similar to the DMIA applying to NSW and the ACT, the DMIS for Queensland and South Australia has two parts, namely:[50]

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46 AER, (2008), *Demand management incentive schemes for the ACT and NSW 2009 distribution determinations – Final Decision*, February 2008. p. 10.

47 Ibid. p. 5.

48 AER, (2008), *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations - Demand management innovation allowance scheme*, February 2008. p. 5.

49 AER, (2007), *Issues Paper - Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009-2014*, November 2007.

50 AER, (2008), *Demand Management Incentive Scheme - Energex, Ergon Energy and ETSA Utilities 2010–15 – Final Decision*, October 2008.

- Part A provides DNSP's with a demand management allowance (DMIA) for the recovery of costs for demand management projects and programs throughout the regulatory control period, subject to satisfaction of defined DMIA criteria. The annual allowance is to be provided ex ante[51] and distributed evenly across each regulatory year with the amount being broadly proportionate to the DNSP's annual revenue requirement.
- Part B allows DNSPs to recover revenue foregone as a result of any reduction in the quantity of energy sold as a result of DMIA approved expenditure. This recovery of foregone revenue only applies to DNSPs whose regulated revenue is subject to a form of control dependent on the quantity of energy sold. As with the DMIA in NSW, the recovery of forgone revenue under Part B is limited to non-tariff demand management initiatives and while revenue available under Part B does not have a specified cap the amount recoverable is limited to approved revenue forgone resulting from successful projects established under Part A of the scheme. However, unlike the DMIA in NSW and the ACT, foregone revenue recoverable under the DMIS is recoverable *in addition to*, rather than under, the expenditure cap set on the DMIA.[52]

The DMIA available to DNSPs is not provided on an annual basis but rather over the regulatory control period as a whole. The AER justifies this on the basis that it creates the incentive for the DNSP to make full use of the allowance within the regulatory control period whilst retaining flexibility in the timing of expenditure so as to best suit the DNSP.[53]

In addition, the AER have indicated that the DMIA is not the sole mechanism to recover the cost of demand management expenditure:[54]

> 'The DMIA is not intended to be the primary source of recovery for demand management expenditure. Rather, the AER considers it appropriate that a DNSP recover demand management costs primarily through forecast opex and capex approved at the time of the AER's distribution determination.'

The AER also introduced a demand management incentive in Victoria. In April 2009, the final decision on a demand management incentive scheme (DMIS) for Victorian DNSPs for the 2011-15 regulatory period was released. The scheme is similar to the DMIA in place in NSW and the ACT and is comprised of two parts:[55]

- Part A – the DMIA – will allow DNSPs to recover their costs for demand management projects throughout the regulatory control period, subject to satisfaction of defined DMIA criteria. DNSPs are to be provided with this allowance ex ante[56] with the amount being

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51 As with the DMIA in NSW and ACT, an annual ex-post review of expenditure is conducted to ensure compliance with the DMIA criteria.

52 Ibid. p 11.

53 Ibid. p. 15.

54 Ibid. p. 14.

55 AER, (2009), *Demand Management Incentive Scheme - Jemena, CitiPower, Powercor, SP AusNet and United Energy 2011–15 – Final Decision.*

56 Similar to the arrangements in NSW/ACT and QLD/SA, an ex-post review of expenditure is conducted to ensure compliance with the DMIA criteria. However, DNSP's can also seek indicative up-front approval of planned expenditure under the scheme, by submitting an application to the AER prior to 31 January in the relevant regulatory year.

proportional to the relative size of their average annual revenue requirement across the previous regulatory control period. DNSPs are afforded discretion in their spending, with the amount that they can spend in any one regulatory year being uncapped, however the total amount recoverable over the regulatory control period cannot exceed the total amount of the allowance which is proportional to their size, or past regulated revenue.

- Part B will allow recovery of forgone revenue by a DNSP where there are reductions in the quantity of energy sold due to expenditure approved under Part A. Similar to the DMIA operating in NSW and the ACT, this occurs when the DNSP is regulated so that their approved regulated revenue is dependent on the quantity of electricity sold. The revenue recoverable under this part is to be limited to non-tariff demand management initiatives.

The AER noted the potential for D-factors to correct the incentive problem but, similar to the ESC, concluded that it was inappropriate to apply a D-factor to Victorian DNSPs. The AER indicated that the benefits of D-factor schemes were not as yet conclusive.

The AER has also indicated its intention to develop a national DMIS.[57] Whilst specific details are not currently known, the AER has specified that uncertainties surrounding national policy issues, such as the Carbon Pollution Reduction Scheme (CPRS) and the AEMC's review of demand side response, currently render the development of a national DMIS inappropriate, ie:[58]

> 'The AER intends to monitor the development of related policy initiatives and consider them in developing a national DMIS in the future. The AER considers that it would be inappropriate to develop a national DMIS before the extent of potential changes to the policy and regulatory framework within which it will operate are known.'

This position differs from that of the targeted innovation funding considered in this report. The targeted innovation funding is, in part, to assist DNSPs in managing the operational uncertainties arising from wider national policy initiatives such as the CPRS and expanded Renewable Energy Target.

3.1.3. Other Australian schemes

However, in the 2009-10 budget, the Australian Government announced that up to $100 million will be invested in partnership with the energy sector for the development of the National Energy Efficiency Initiative: Smart Grid, Smart City. The majority of the funds are to be used to trial a large-scale smart grid and smart meters project aimed at demonstrating the benefits of a transition smart grid technology as well as encouraging innovation in such technology. Specifically, smart meters will allow electricity businesses to introduce innovative tariffs such as time of day, and critical peak pricing tariffs in order to align prices more directly with the cost of providing electricity (both generation and network capability) during different times of the day or periods in the year.

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57 AER, (2009), *Demand Management Incentive Scheme - Jemena, CitiPower, Powercor, SP AusNet and United Energy 2011–15 – Final Decision.*

58 Ibid. p. 5.

Smart grid technology is expected to improve the scope for distributors to manage distributed generation connections to the network, through smart network monitoring and operations. Innovations in this area are therefore likely to go some way to facilitating the increased numbers of distributed generation connections expected following the introduction of the CPRS and the expanded RET.

The arrangements surrounding the licensing of DNSPs in NEM jurisdictions all include provisions that require the consideration of demand-side alternatives to network augmentation. The associated legislation includes the mandatory condition that the holder of a distributors' licence must investigate, and report, whether demand-side (or namely demand management) options would be a cost-effective solution to network augmentation. For example NSW legislation imposes:[59]

> 'a condition requiring the holder of the licence, before expanding its distribution system or the capacity of its distribution system, to carry out investigations (being investigations to ascertain whether it would be cost-effective to avoid or postpone the expansion by implementing demand management strategies) in circumstances in which to would be reasonable to expect that it would be cost-effective to avoid or postpone the expansion by implementing such strategies'

To investigate demand-side alternatives to network augmentation, there are various government grants and concessions that DNSPs may be eligible to apply for. A number of Commonwealth, state and territory government departments offer grants to encourage innovation and research and development into areas particularly focused on energy efficiency, renewable energy and the impact of climate change polices more generally.

3.1.4. Summary

The table below provides a summary of the various schemes in place across Australia.

[59] Clause 6 (5) (a) in Schedule 2 of the NSW *Electricity Supply Act 1995*.

Table 3.1: Summary of Australian demand management funding arrangements

	Form of regulation	Form of funding	Length of funding	Selection criteria
ESC	WAPC	$600,000 allowance over the regulatory period.	5 years (2006-10 regulatory period).	-
VIC†	WAPC	DMIA* and forgone revenue. Forgone revenue is recoverable *under* the capped allowance.	5 years (2011-15 regulatory period).	AER DMIA criteria.
IPART	WAPC	D-factor.	DNSPs receive benefit for 2 years.	IPART Guidelines
NSW/ACT†	WAPC/ARC	DMIA* and forgone revenue in addition to D-factor for NSW. Forgone revenue is recoverable *under* the capped allowance.	5 years (2009-14 regulatory period).	AER DMIA criteria.
ESCOSA	Revenue yield	Allowance of up to $20m over the period.	5 years (2005-10 regulatory period).	-
SA/QLD†	WAPC/FRC	DMIA* and forgone revenue. Forgone revenue is recoverable *in addition to* the capped allowance.	5 years (2010-15 regulatory period).	AER DMIA criteria.

*Note: † indicates an AER scheme and * denotes that that DMIA is capped at an amount broadly proportionate to the DNSP's average annual revenue requirement. Also, WAPC, ARC and FRC stand for weighted average price cap, average revenue cap and fixed revenue cap forms of regulation respectively.*

3.2. International innovation funding schemes

The United Kingdom and United States also have in place incentives to encourage network businesses to undertake research and development projects. These measures have largely been developed as a result of the impact of climate change policies and a growing interest in the ability of demand-side options to provide more efficient and effective solutions than network augmentation. This section describes these schemes.

3.2.1. United Kingdom

Ofgem introduced an incentive mechanism for DNSPs to facilitate the connection of distributed generation (DG) to their networks.[60] The 'DG Incentive' was introduced in response to the UK government adopting specific targets for the amount of energy to be

60 Ofgem, (2004), *Electricity Distribution Price Control Review - Final Proposals*, November 2004.

supplied by renewable generation and the capacity of combined heat and power to be installed by 2010.[61]

In addition to the DG Incentive, Ofgem has also implemented an Innovation Funding Incentive (IFI) scheme and a Registered Power Zones (RPZ) scheme. The IFI scheme was designed as a mechanism to encourage Distribution Network Operators (DNO) to invest in appropriate research and development activities that focus on the technical aspects of network design, operation and maintenance.[62] The ultimate objective of the scheme is to deliver benefits to end customers by enhancing efficiency in network operating costs and capital expenditure. Whereas the RPZ scheme is a mechanism to encourage DNOs to develop and demonstrate, on their networks, innovative and more cost effective ways of connecting and operating generation.[63] The scheme was designed to recognise that for some new DG connection schemes, an innovative technical solution could offer material advantages to DG customers compared with a conventional solution.[64]

Both initiatives were established to develop the regulatory framework to help accommodate the expected increase in the amount of DG. However, both the IFI and RPZ schemes were developed as temporary solutions to difficulties associated with facilitating the connection of DG:[65]

> 'The IFI and RPZ initiatives are intended to act as catalysts, bringing together DNOs, product providers, service providers, and the research community to accelerate the innovation process and deliver new solutions more efficiently. They are transitional arrangements intended to be in place until DG becomes "business as usual"; it is thought unlikely that this would be before 2010.'

The IFI scheme allows a DNO to spend up to 0.5 per cent of its regulated revenue on 'eligible' IFI projects[66] and that funding is on a 'use-it-or-lose-it' basis.[67] Companies can only carry forward from one year to the next year up to 50 per cent of the maximum allowable IFI funding for a given year and cumulative carry forward is not allowable, hence 'use-it-or-lose-it'. Eligibility is determined via a 'good practice guide' (GPG), which companies have to produce and comply with for managing their research and development projects as part of the regulatory framework.[68] Ofgem states the rationale for establishing a GPG as being:[69]

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[61] Ofgem, (2004), *Electricity Distribution Price Control Review - Final Proposals*, November 2004.

[62] Ofgem, (2006), *Open Letter Consultation on the Innovation Funding Incentive and Registered Power Zone Schemes for Distribution Network Operators*, 5 October 2006

[63] Ibid.

[64] Ofgem, (2004), *Electricity Distribution Price Control Review - Final Proposals*, November 2004.

[65] Ofgem, (2003), *Innovation and Registered Power Zones - Discussion Paper*, July 2003. p. 4.

[66] Ofgem stated "IFI projects might be expected to embrace all aspects of distribution system asset management from design through to construction, commissioning, operation, maintenance and decommissioning." – Ofgem (2004) *Electricity Distribution Price Control Review - Final Proposals*, November 2004. Paragraph 5.40.

[67] Ofgem, (2004), *Electricity Distribution Price Control Review - Final Proposals*, November 2004. Paragraph 5.41.

[68] Ofgem, (2005), *Further Details of the RPZ Scheme Guidance Document - Version 1*, April 2005. Paragraph 3.1.

[69] Ibid. Paragraph 1.4.

> 'intended to establish a common code of practice across the industry and deliver a coherent approach between DNOs undertaking RPZ and IFI projects.'

The IFI scheme provides DNOs with a partial pass through of the costs associated with their research and development activities. This reflects the importance of exposing DNOs to some of the financial risk of research and development to encourage efficient expenditure. The table below outlines the extent of the pass through for each of the years since the IFI scheme has been in place. The decreasing pass-through rate has the further advantage of providing a greater incentive for projects at the start of the period.[70]

Table 3.2: Pass-through of the IFI

Year	2005/6	2006/7	2007/8	2008/9	2009/10
Pass-through rate	90%	85%	80%	75%	70%

In 2007, Ofgem announced that it intended to continue the IFI scheme through the next regulatory control period. The previous scheme arrangements remained except the pass-through rate was set at 80 per cent and the cap on internal funding was removed.[71]

In contrast to the IFI scheme, the RPZ mechanism is focused specifically on the connection of DG and is an extension of the DG Incentive. The DG Incentive allows DNOs to recover their generation connection costs via a combination of pass through and incentive per kW connected.[72] If a DNO connects generation in an innovative way then it can seek to register the connection scheme with Ofgem as an RPZ.[73] Ofgem uses a set of published criteria to determine the validity of the 'innovation' which, if deemed so, means the incentive element of the DG Incentive increases for the first five years of operation by £3/kW.[74] The additional revenue a DNO can claim, ie the revenue generated from the £3/kW uplift, each year is capped at £0.5 million.[75]

In December 2008, Ofgem released a policy paper for the upcoming regulatory control period which, among other things, expressed concern that the IFI and RPZ schemes did not go far enough in encouraging DNOs to undertake research and development and to be more innovative in the connection of DG.[76] Following this, Ofgem have suggested a low carbon network (LCN) fund in addition to the IFI scheme to encourage innovation. [77] Ofgem also

[70] Ofgem, (2004), *Electricity Distribution Price Control Review - Final Proposals*, November 2004. Paragraph 5.42.

[71] Ofgem, (2007), *Open Letter Consultation on the Innovation Funding Incentive and Registered Power Zone Schemes for Distribution Network Operators*, 14th February 2007

[72] Ofgem, (2004), *Electricity Distribution Price Control Review - Final Proposals*, November 2004. Paragraph 5.5.

[73] Ofgem, (2005), *Further Details of the RPZ Scheme Guidance Document - Version 1*, April 2005. Section 4.

[74] Ibid. Paragraph 2.10.

[75] Ibid. Paragraph 2.16.

[76] Ofgem, (2008), *Electricity Distribution Price Control Review - Policy Paper*, 5 December 2008.

[77] Ofgem, (2009), *Electricity Distribution Price Control Review - Initial Proposals - Incentives and Obligations,* 3 August 2009,

stated their intention to discontinue the RPZ scheme on the basis that any innovative DG connection projects that would fall under it can be funded via the LCN fund.[78]

The LCN fund is a new fund which proposes "a total of £500m over DPCR5 to fund the trialling of innovative technological or commercial arrangements intended to solve problems on networks relating to sustainable development."[79] The fund is proposed to be split across two tiers:[80]

- Tier 1 is provided to allow DNOs to react quickly to changing circumstances. Funding is self-audited by the DNOs against specific guidance similar to the IFI in order to lower administrative overhead costs; [81] and
- Tier 2 is proposed to be a much greater amount with funds distributed between DNOs on a competitive basis. It is proposed that only a limited number of projects can be submitted under this tier and on an annual basis so as to reduce the administrative burden and cost. Projects funded under this tier are expected to be of significant scale with the potential for national rollout. The costs of projects under Tier 2 are to be socialised, where the revenue required to fund these costs is to be shared across all DNOs in the expectation that benefits will accrue nationwide.

Ofgem have proposed that the cost of projects under this scheme is to be shared, with the LCN fund only funding a maximum of 90 per cent of the project cost and the DNO funding the remaining 10 per cent.[82] Ofgem have noted that where a DNO identifies direct, or 'commercial', project benefits to them from a trial that the DNO funding will form a greater percentage of the project cost.

3.2.2. United States

In December 2007 the *Energy Independence and Security Act 2007* was enacted. The Act recognised the importance of developing an electrical smart grid, and included specifications for the funding of smart grid research, development and demonstration and a federal matching fund for smart grid investment costs.[83] Specifically, authorised funding included:[84]

- the development of the Department of Energy's (DOE) Smart Grid Investment Grant Program which includes: grants ranging from US$500,000 to US$20 million for smart grid technology deployments; grants of US$100,000 to US$5 million for the deployment of grid monitoring devices; and matching grants of up to 50 per cent for investments planned by electric utilities and other entities to deploy smart grid technologies. US$3.375 billion was allocated to this initiative; and

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78 Ibid. p. 12.

79 Ibid. p. 5.

80 Ibid. p. 165.

81 Ofgem note that they reserve the right to disallow any monies spent that do not confirm to the guidance.

82 Ibid. p. 5.

83 Sections 1304 and 1306 of the *Energy Independence and Security Act 2007* respectively.

84 U.S. Department of Energy Media Release, Vice President Biden Outlines Funding for Smart Grid Initiatives, April 16 2009.

- an additional US$615 million for smart grid demonstration projects, these included: smart grid regional demonstrations; utility-scale energy storage demonstrations; and grid monitoring demonstrations.

The Advanced Research Projects Agency-Energy (ARPA-E) was established in 2007 as a new organisation within the DOE, created to encourage research and development of 'transformational' energy-related technologies. Transformational technologies are defined as technologies that disrupt the status quo, they are stated as being not merely better than current technologies but rather they are significantly better. The ARPA-E was modelled after the Defence Advanced Research Projects Agency[85] and was established to focus investment in high risk, high payoff research and development, noting that the DOE invests a significant amount in basic research and ARPA-E is not intended to supplement these efforts.[86] Most recently, the *American Recovery and Reinvestment Act* of 2009 approved US$400 million in research funding for the DOE's ARPA-E program.[87]

In February 2009, the *American Recovery and Reinvestment Act* was signed into law in the United States by President Obama. Under the Act the DOE is responsible for implementing over US$40 billion worth of funding which will largely support implementation of the Smart Grid programs authorised by the *Energy Independence and Security Act* of 2007. As part of the *American Recovery and Reinvestment Act* US$11 billion has been appropriated for research and development, pilot projects, and federal matching funds for the Smart Grid Investment Program as well as US$2.5 billion for energy efficiency and renewable energy research, development, demonstration, and deployment activities.[88]

In addition to Federal initiatives, a number of states have enacted their own research and development funding schemes. For example, the Californian Energy Commission has in place a Public Interest Energy Research (PIER) program. The PIER program provides contracts and grants in the support of public interest energy research, development and demonstration.[89] In 2008, the California Energy Commission administered a total of US$83.5 million for research through the PIER program, with approximately US$62.5 million for electricity projects.[90] The funds collected as part of the PIER program are collected annually from the investor-owned Californian electric utilities.[91]

New York State has an Energy Research and Development Authority (NYSERDA) which funds research into energy supply and efficiency, as well as energy-related environmental

85 The Defence Advanced Research Projects Agency is credited with helping provide the Internet, the stealth aircraft, as well as many other technological breakthroughs - The Department of Energy (2009) *Fact Sheet: A Historic Commitment to Research and Education*, 27 April 2009.

86 ARPA-E website, available at www.arpa-e.energy.gov

87 U.S. Department of Energy, (2009), *Program Specific Recovery Plans - Advanced Research Projects Agency – Energy*, 15 May 2009.

88 US House of Representatives Committee on Appropriations (2009) *Summary: American Recovery and Reinvestment - Conference Agreement*, 13 February 2009.

89 The Californian Energy Commission website, available at www.energy.ca.gov/research/index.html

90 California Energy Commission, (2009), *California Energy Commission Public Interest Energy Research – 2008 Annual Report*, March 2009.

91 Ibid.

issues with funding coming primarily from state rate payers through the System Benefits Charge[92]. NYSERDA publicly requests proposals, from any private or institutional entity, to submit project plans to address energy and environmental issues that NYSERDA has highlighted. Projects are chosen on a proposer's experience, concept and scope of work, detailed costs and schedule for completion.[93] If funding is granted, a project's costs are usually shared between NYSERDA and the proposer.[94]

A key feature of the US funding arrangements, both at a Federal and State level, is that a central research and development fund is commonly established, as opposed to incorporating funding initiative into specific regulation. Funding is then allocated to interested parties on a competitive basis and eligible parties are not confined to one particular group. This means that any party with demonstrated experience can submit a proposal for funding.

[92] The Systems Benefit Charge was established to fund public policy initiatives not expected to be adequately addressed by New York's competitive electricity markets. The current SBC in place until 30/6/2011 and has an annual funding level of US$175 million - New York State Public Service Commission website, available at www.dps.state.ny.us

[93] NYSERDA website, available at www.nyserda.org

[94] Ibid.

4. An Australian innovation funding scheme for distributors

Having examined the existing arrangements for funding research and development, and the international experience, this chapter considers whether an innovation funding scheme is required for distributors in the NEM, and the design options for a scheme.

4.1. Is an innovation funding scheme required?

In chapter 2 we identify that under the current regulatory framework there is an 'in principle' incentive problem with the existing arrangements. However, current arrangements in Australia already address many of the incentive problems, specifically for research and development aimed at facilitating demand-side participation. For this reason, there does not appear to be a strong case for introducing a new scheme or enhancing the existing arrangements for funding research and development into demand-side participation.

That said the existing arrangements are not readily capable of addressing the lack of incentive for distributors to engage in actions to facilitate the connection of increasing numbers of distributed generation and intermittent generation – both of which are expected to increase as a consequence of the introduction of the CPRS and the expanded RET.

We believe therefore that there is a significant potential impediment to distributors undertaking the necessary research to respond in a timely manner to these connection challenges (and indeed other challenges that will inevitably arise). We therefore believe that there is merit in introducing an innovation funding scheme for a limited duration focused on the connection challenges.[95] To this end, we believe that there is merit in having a review five years after its introduction by the AER. The terms of reference for such a scheme review should explicitly require the AER to consider whether the continuation of the scheme is warranted.

While we believe that a scheme is warranted, we acknowledge that there is limited evidence available about the likelihood that distributors will not respond adequately within the existing arrangements. In considering the alternative design options below, we have been mindful of developing a scheme that is proportionate to the extent of the perceived problem.

4.2. Scheme design options

It is paramount that the design elements of any innovation scheme provide distributors with the appropriate incentives to invest efficiently in innovation while being proportionate to the extent of the incentive problem. There are a number of scheme design elements for which alternative options are available, namely:

- administration of the scheme;
- source of funds;

[95] The Ofgem scheme was originally established as a 'temporary scheme' until such time as the implications of the European emissions trading scheme had been better understood. That said the scheme has recently been extended as part of Ofgem's most recent decision.

- quantum of funds;
- project selection criteria; and
- extent of cost sharing between distributors and end-use customers.

Each of these scheme design elements is discussed in further detail below.

4.2.1. Administration of the scheme

There are two principal scheme administration options, namely:

- a centralised scheme approach, where all funds are received centrally and allocated to distributors on the basis of project bids subject to satisfaction of selection criteria; or
- a decentralised scheme approach, where distributors are allowed to pass some or all of the cost of research and development to customers up to a capped amount.

A centralised scheme approach would establish a NEM wide entity (possibly the AER or an alternative agency) with responsibility for the innovation scheme. This responsibility would extend to the development of project funding criteria, the evaluation of project funding bids, dissemination of project findings and evaluation of project outcomes. The principal advantages of a centralised scheme approach is that it:

- ensures coordination of innovation projects by having a centralised agency having discretion to choose between alternative project funding proposals;
- facilitates dissemination of project outcomes either directly (ie, by the AER itself), or by obliging project proponents to publish project outcomes as a condition of funding;
- potentially allows other parties (eg, third party researchers, universities, research and development businesses, etc) to seek and receive funding for projects that otherwise satisfy the project funding criteria; and
- certainty of funding for distributors, because a project would not commence until it had been approved by the innovation funding scheme agency.

Its disadvantages including:

- potentially large administrative burden associated with the preparation and lodgement of proposals to undertake research and development projects; and
- it will likely limit the scope for distributors to respond quickly to changing circumstances.

In contrast, a decentralised scheme approach would allow a distributor to undertake innovation projects directly from an innovation project funding allowance determined as part of the scheme. Such an approach might apply a ‘use-it-or-lose-it’ funding approach whereby any amount left over from the allowance is returned to customers over the subsequent regulatory period.

The advantages of a decentralised scheme approach include:

- a lower administrative burden because project proposals would not have to undergo third party scrutiny; and
- flexibility for the distributor to respond quickly to changing circumstances, without the need to seek approval from a centralised scheme funding agency.

The disadvantages include:

- potential project overlap as multiple distributors undertake projects to address similar concerns;
- uncertainty about funding (particularly if there is scope in the scheme design for a third party to retrospectively disallow funding for a project that it considers did not satisfy the scheme criteria); and
- limits participation to distributors and their agents, and so limits the scope for innovation to develop by third parties.

To balance the advantages and disadvantages of both of these approaches, the Ofgem scheme provides a small quantum of funds directly to distributors to give each distributor the flexibility to respond to changing circumstances. In addition, there is a centrally administered fund for which distributors can submit project proposals.

In our opinion, in light of the uncertainty about the need for and so materiality of the current incentive problem, particularly given the availability of other funding sources (eg, the smart grid initiative), a small decentralised fund would be the most appropriate. Such an approach would avoid the potentially large administrative costs of the centrally administered approach, while addressing any possible concern about a lack of incentives within the existing arrangements for distributors to respond to the challenges created through the implementation of climate change policies.

However, should evidence arise to support the need for additional innovation funding, then we would support the creation of a centrally administered fund, for which distributors could submit proposals for funding.

4.2.2. Source of funding

Irrespective of whether the scheme is centrally or de-centrally administered, there are two possible options for the source of funding for the scheme, namely:

- electricity users, by increasing the price of electricity paid in order to fund the scheme; or
- general taxpayers via consolidated revenue.

The choice between these two alternatives rests on a philosophical view as to whether the beneficiary or causer should pay for such research and development, as a consequence of the government implementing carbon reduction policies. Arguably electricity users are the beneficiary of such research presumably through cost efficiencies that would be expected to lower electricity prices. The government (and so taxpayers) could be considered as the ‘causer’ because such innovation might not have been otherwise required in the absence of carbon reduction policies.

In our opinion there is merit in requiring electricity users to fund such innovation investments, as compared with taxpayers because:

- the implications of carbon reduction policies should be considered as a ‘cost of doing business’ for distributors like any other government regulatory requirement;
- if government was made responsible for the business cost implications of its decisions, almost all government decisions would result in compensation to the parties affected – a financially unsustainable position; and
- users are expected to benefit from the payoffs that would result from such investments, and so should be obliged to fund the investments in the first place.

4.2.3. Quantum of funds available

The next question is to consider how much should be available in total for innovation projects funded through the scheme.

As outlined earlier Ofgem’s IFI scheme allows a distributor to spend up to 0.5 per cent of its regulated revenue on innovation projects that meet the published criteria. We calculate this to be equivalent to $15 million for all distributors in New South Wales in 2009/10, or approximately $3.50 per customer.[96]

An alterative approach to determining the funding allowance as a proportion of revenue requirements is to determine a fixed amount to be added to each distributor’s revenue requirement as the funding amount (say $10 million). Such an amount could be indexed by the rate of change of general prices over time, as measured by the consumer price index.

In our opinion determining the innovation funding allowance as a proportion of a distributor’s revenue requirement should be preferred because it ensures that a customer pays the same proportion of its bill to the innovation scheme, regardless of the revenue requirement of the specific business. The alternative approach could result in customers of distributors with smaller revenue requirements per customer paying proportionately more into the innovation scheme as compared to customers of distributors with larger revenue requirements per customer.

That said there is no strong case to support a particular percentage of revenue requirement choice. The advantage of a relatively small percentage (say 0.5 per cent) is that it does not result in a large impact on customers, but is sufficient to allow the need for innovation funding to be evaluated. In our opinion, any funds not used during a year should be returned to customers at the next regulatory price reset.

4.2.4. Selection criteria

To ensure that the scheme funds are appropriately spent on projects that promote the scheme objectives, a set of project evaluation criteria are needed.

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[96] These estimates have been made using annual revenue requirements and customer numbers for Country Energy, EnergyAustralia and Integral Energy published in the Australian Energy Regulator’s final decision for the 2009/10 – 2013/14 regulatory determination.

There are two approaches for the project evaluation criteria, namely: the use of detailed and specific criteria or alternatively, the use of high level criteria. Detailed and specific criteria are appropriate in circumstances where large amounts are in question and so detailed accountability about the appropriateness of a particular project is required. A disadvantage of detailed criteria is that it can create funding uncertainty, particularly if the AER is allowed to ex post determine whether a project satisfies the criteria.

High-level criteria may be appropriate if the funds in question are relatively small and there is a desire to provide flexibility to distributors, thereby encouraging them to engage in innovative projects.

In our opinion, a small and decentralised funding scheme (such as our preferred approach) should be supported by high-level criteria where there is only limited discretion for the AER to ex post disallow funding. This approach strikes an appropriate balance between providing certainty of funding to distributors to encourage innovative research and development, while minimising the administrative costs of the scheme.

The DMIA criteria include:

- specifying the nature of projects that can be funded by the allowance (ie, demand management projects or programs);
- guidance on the types of programs that are appropriate (eg, peak demand projects, broad based demand reduction projects);
- guidance on the outcomes from the project, including to build capability and capacity and be innovative;
- clarification that proposed projects can be either tariff or non-tariff based;
- clarification that costs recovered through the allowance cannot also have been recovered from other funding sources; and
- clarification that expenditure can be either operating or capital expenditure.

As we outline further below, one approach to implementation is to extend the existing DMIA to include projects that address innovation in the connection of distributed generation. We therefore propose that in addition to the DMIA criteria (as applicable) an additional criteria be added, namely:

- to include projects or programmes that seek to facilitate innovation in the operation and management of the electricity distribution network in response to distributed generation connections; and
- to clarify that projects and programmes can relate to specific generation types, or more broadly to improving the entire operation and management of the electricity network in response to an increasing number of distribution generation connections.

Further consideration should be given to the need for additional selection criteria, if required.

4.2.5. Cost sharing

The final design question relates to the extent that costs, and so risks, of a specific project are shared between the distributor and customer. Choices about risk sharing between distributors and customers have implications for the incentives created to choose projects that are likely to deliver benefits.

There are two broad approaches, namely:

- where customers bear all of the costs and so are entitled to all of the benefits that might result; or
- a hybrid approach where customers bear only a proportion of the total cost of a proposed project and so the distributor is entitled to share some of the benefits of the scheme.

The first option is likely to result in a moral hazard given the nature of the projects likely to be funded. A moral hazard describes the prospect that, if insulated from risk, a party will behave in a different manner than if it were exposed to some risk. Since research and development projects are inherently risky with the likelihood of the outcomes being realised often small, a distributor receiving the entire funding for a project may be inclined to pursue projects it otherwise would not if it shared some of the risk.

Alternatively if distributors shared some of the costs, and so risk, of funding research and development then the size of this moral hazard problem diminishes – as in the hybrid approach. As outlined earlier Ofgem have provided distributors with only a partial pass through of innovation project costs, in order to expose the distributor to some of the risks associated with the project and so minimise the scope for completely unwarranted projects being undertaken.

For these reasons, we believe there is merit in having some portion of the costs of an innovation project funded by the distributor. In practice this would mean that a distributor would only be entitled to claim a proportion of the cost of a proposed innovation project from the scheme funds.

4.3. Implementation arrangements

In light of the introduction of the CPRS in 2010, there is merit in implementing the proposed innovation funding scheme prior to the next regulatory price reset (which for some distributors is almost five years away). This will ensure that funds are available to distributors to commence innovative projects as soon as practical.

There are a number of alternative pathways to implement such a scheme prior to the next round of regulatory resets, specifically:

- require through a change to the National Electricity Rules for the AER to widen the scope of its demand management incentive allowance to include those additional innovation activities relating to generator connection to the network; or

- develop an alternative innovation funding scheme in the rules, to allow distributor revenue requirements to increase by the innovation funding requirement (say 0.5 per cent of maximum allowable revenue).

Whether either approach can be implemented through changes to the rules is ultimately a legal question that will need to be considered further. Putting to one said whether it is legally possible for each option to be implemented, the first approach is likely to be the simplest and will satisfy all of the scheme design preferences set out above, except for risk sharing between distributors and customers. To create this incentive the rules could require that any scheme developed in accordance with the rules oblige only a percentage of costs be recovered from the scheme allowance amount.

We do not believe that there are particular advantages from the second approach however there would be a need to undertake further detailed scheme design prior to its incorporation in the rules.

Finally, we acknowledge that the Federal Government's $100 million investment in smart grid technologies will likely go some way to fund innovation to address the concerns that have been raised about the network implications of an increase in distributed generation connections. However, it is likely that each distributor will also need to undertake its own smart grid technology trials in the future to determine how such technologies can be best used within its own network, and so funding will be needed for these trials. In addition, the smart grid funding does not allow other innovations that might otherwise develop to manage distributed generation connections, in the absence of smart grid technologies. That said, if it is legally difficult to implement the proposed scheme ahead of the next round of regulatory resets, the smart grid investment might go some way to addressing the incentive concerns that have been raised in this paper.

4.4. Summary

In summary we believe that there is merit in extending the AER's demand management incentive scheme to include those additional innovation activities relating to generator connection to the network. The consequential changes to the rules include:

- requiring the allowance be increased by a fixed proportion of the maximum allowable revenue for each distributor (say 0.5 per cent);
- requiring the project scope to be expanded to include innovation projects relating to generation connection; and
- requiring that distributors can only recover a portion of the total project costs (say 80 per cent).

5. Conclusions and recommendations

In this report we have examined whether a separate innovation funding scheme is required for distributors in the NEM. Our approach involved first setting out the innovation incentive problem before considering innovation funding arrangements in place in both Australia and abroad. This was followed by an evaluation of the need for an innovation funding scheme, and alternative design options and approaches to implementation.

In our opinion there is merit in introducing a decentralised innovation funding scheme, by expanding the AER's demand management innovation allowance to include projects relating to connection of generation.

We therefore recommend that:

- the scheme be implemented as soon as possible, given rule making and other legal requirements. This will allow distributors to commence projects in anticipation of the need following the introduction of the CPRS and the expanded RET;
- total additional funding available in the first regulatory year be no more than 0.5 per cent of total annual revenue requirement (ARR) for each distributor in the NEM;
- consequential changes to the rules are developed to:
  - require the demand management innovation allowance be increased by a fixed proportion of the maximum allowable revenue for each distributor (say 0.5 per cent);
  - require the project scope to be expanded to include projects relating to generation connection;
  - require that distributors can only recover a portion of the total project costs (say 80 per cent); and
- the scheme should be introduced for a limited period of time, with a review of the scheme's effectiveness before 5 years following implementation.

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