Attachment 3.03

Application of Demand Management Embedded Generator Connection Incentive Scheme (DMEGCIS) proposal

May 2014

1.1 Role of Demand management Schemes

The proposed application of the Demand Management Embedded Generator Connection Incentive Scheme (DMEGCIS) is a simple, easily administered, low risk and low cost way of promoting efficient DNSP investment in line with the National Electricity Law Objectives.

A Demand Management Scheme (currently the Demand Management and Embedded Generation Connection Incentive Scheme or DMEGCIS) is an integral part of the CPI-X regulatory incentive framework. It addresses long-standing concerns by regulators, policy makers and stakeholders about the failure of DNSPs to include efficient non-network solutions, including demand management and embedded generation, in their investment decisions. It should provide incentives to ensure demand management and non-network solutions are treated on at least an equal basis with network solutions, address barriers to efficient DM in the NEM and fulfill the NEL objectives. It should work in harmony with related parts of the regulatory investment and incentive framework particularly the RIT-D, STPIS and CESS and EBSS but also the switch from deterministic to probabilistic planning under new NSW license conditions from July 1st 2014.

1.2 Background

The DMEGCIS incentives for NSW in 2009-14 were a carry forward of the IPART D-factor incentive created in 2004 for the 2004-09 regulatory period, to which a "use-it-or-lose-it" Demand Management Innovation Allowance (DMIA) was added to fund non-commercial DM R&D expenses.

The AER under clause 6.6.3(b) of the NER must have regard to developing and implementing a DMEGCIS (DMS) as part of its regulatory framework and approach. The AEMC "Power of Choice" review and Productivity Commission Inquiry into Electricity Network Regulatory Frameworks both supported DM incentives and the inclusion of market benefits in a new DMS – this is to be reflected in Total Environment Centre (TEC) and SCER rule change proposals to be published in early 2014.

The AER proposed to continue applying Part A of the DMIA at the same scales as currently applied to NSW DNSPs, but to discontinue Part B of the scheme as it related to compensation for foregone revenue. Our proposal is to apply the AER's approach given that we are no longer under a weighted average price control cap.

The AER also proposed to discontinue the non-compensationary incentive component of the D-Factor scheme, which is not related to foregone revenue, for NSW distributors from the transitional regulatory control period onwards. Our proposal is to replace and improve the incentive component of the D-Factor scheme with a Demand Management Benefit Sharing Scheme (DMBSS) which shares with customers the upstream market benefits from DNSP demand reductions. .

The AER has noted that the Standing Council on Energy and Resources (SCER) is currently considering a series of rule changes proposed by the AEMC in its Power of Choice review examining distributor incentives to pursue efficient alternatives to network augmentation. Our proposal for a DMBSS market benefits based incentive is consistent with the SCER policy intent, Section 6.6.3 of the National Electricity Rules, proposed rule changes and the RIT-D process. In compliance with NER Clause s6.1.3 (5) further details of the proposed DMBSS are provided below.

1.3 Proposed DM Scheme for 2015-19

The AER's Stage 2 Framework and Approach paper January 2014 has stated:

”We propose to continue applying the DMIA to NSW distributors in the transitional period and subsequent period. But, we propose to discontinue the D-Factor scheme for NSW distributors from the transitional period onwards.

The Standing Council on Energy and Resources (SCER) is currently considering a series of rule changes proposed by the AEMC in its Power of Choice review examining distributor incentives to pursue efficient alternatives to network augmentation. This will include new rules and principles guiding the design of a new DMIS. Whether we are able to develop and implement a new DMIS for the subsequent period, depends on the progress of the rule change process and the inclusion of any relevant transitional provisions”.

Consistent with the AER rule change and RIT-D process we propose a simplified DMS with two parts: continuing a $1m per annum DMIA as proposed by the AER; and a Demand Management Benefit Sharing Scheme (or DMBSS). The DMBSS will remove the complexity of the D-Factor’s foregone revenues, avoided distribution cost cap, delayed cost recovery and project cost simulation while being aligned with the RIT-D process and the NEL objectives, We propose:

- a $100 per kVA Incentive in 2013/14 dollars to reflect a 50% share of upstream market benefits from DM (a rounding up from average cost of extra capacity of $90 kVA for Transmission and $95 kVA for peaking generation plant in 2012 dollars, as would be used in RIT-D evaluations)

- kVA and benefit calculation methods to be the same as those used for RIT-D evaluations

- DMBSS incentives to be included in the “i factor” in the year following a secured commitment to reduce demand.

A 50/50 split is considered a reasonable sharing with customers and has been proposed by TEC in supporting their rule change application. Customers’ share of the market benefits of DNSP demand management will be reflected in their bills thorough lower transmission and generation charges.

1.4 Demand risk management size in a low growth, revenue caped environment

The regulatory period 2015-16 to 2018-19 - with lower forecast peak load growth, lower augmentation capex, and a revenue cap provides a stable environment in which a DMBSS can be implemented with low cost, low risk and at a manageable scale.

The amount of a new DMBSS incentive will depend on opportunities for DM as they appear at a local level and it is uncertain. However, 10 to 15MW of load reduction per annum (representing $1-1.5M in incentives) is a reasonable estimate of the annual opportunity for new locational DM project. This is less than current D-factor incentive payments and has very limited potential to increasing beyond this amount given current low demand growth forecasts. However, if risks of increased load growth and augmentation expenditure did emerge a DM incentive provides a cost effective hedging mechanism to encourage DNSPs to manage uncertainty and emerging risk with non-network options.

1.5 NER areas for consideration in developing & implementing a DM incentive scheme

This section address issues that, under the National Electricity Rules S6.1.3(5) the AER must have regard to “In developing and implementing a demand management and embedded generation connection incentive scheme”. These cover six issues:

(1) the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for Distribution Network Service Providers;

Response - This is met though a 50/50 sharing of benefits with customers, future benefits from lower DNSP augmentation investment and the greater risk management options provided by DM investments.

(2) the effect of a particular control mechanism (i.e. price – as distinct from revenue – regulation) on a Distribution Network Service Provider's incentives to adopt or implement efficient non-network alternatives;

Response - this is addressed by dropping the foregone revenue compensation component of the D- factor mechanism but proposing an improved market benefit sharing incentive

(3) the extent the Distribution Network Service Provider is able to offer efficient pricing structures;

Response - the proposed DMBSS would apply to a range of possible DM programs which will be complementary to but independent of specific pricing structures

(4) the possible interaction between a demand management and embedded generation connection incentive scheme and other incentive schemes under clauses 6.5.8, 6.5.8A, 6.6.2 and 6.6.4;

Response - as DM tends to replace capex with opex its effects should be removed from the EBSS but retained in STPIS and CBSS as these are part of the building block assumptions built into revenues for which a DMBSS would be providing an efficient non-network alternative

(5) the willingness of the customer or end user to pay for increases in costs resulting from implementation of the scheme; and

Response – "willingness to pay" studies have shown a reluctance for customers to pay for higher or accept savings for lower service levels. A DMBSS will reduce costs consistent with NEL Objectives in the long run interest of customers by delivering cost effective non-network options in place of network solutions. As the RIT-D investment evaluation process will ensure cost will be lower than benefits customers should not see increases as a result of the DMBSS.

(6) the effect of classification of distribution services, as determined in accordance with clause 6.2.1, on a Distribution Network Service Provider's incentive to adopt or implement efficient Embedded Generator connections.

Response – adopting or implementing efficient Embedded Generator connection is not inhibited but should be enhanced by incentives to support non-network solutions.

Appendix A

DMBSS simple calculation example

The amount of the DMBSS to be included in future network prices would:

- Have kVA and benefit calculation methods to be the same as those used for RIT-D evaluations
- Be calculated for the year a demand reduction commitment is made
- Be available for audit and review in the year a commitment is made included in the I-factor in the year following a commitment
- Be included in the I-factor in the year following a commitment
- Measure demand reductions as the weighted average of committed load impacts in transmission & distribution
- Use the calculation methodology for demand reduction used for RIT-D analysis
- Measure kVA as the capacity to manage forecast demand, as is done with network assets
- Exclude any DM projects identified as part of the building blocks of regulated revenue
- Have its impacts removed from the EBSS calculations but remaining in STIPIS and CESS.

The example below indicates how the demand reductions from a range of audited projects would be applied.

Estimated Demand reductions in financial year 2016

Project	**kVA reduction**
Project 1	200
Project 2	500
Project 3	1200
Total - (a)	**1900**
KVA incentive	
Real	$100
Inflator	1.05
Nominal - (b)	**$105.06**
Add to i factor - (a) x (b)	**$199,619**