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18 January 2013

Mr Peter Varela
Research Economist
Electricity Networks Regulation
Productivity Commission
GPO Box 1428
Canberra City ACT 2601

Via email: electricity@pc.gov.au

Dear Peter,

Productivity Commission Inquiry - Electricity Networks Regulation

I refer to your email dated 18 December 2012 which sought additional information on transmission investment to assist the Productivity Commission in preparing its final report on network regulation arrangements. In response, the following is included with this letter:

- A response to your questions on the example on page 18 of the Grid Australia submission provided to the Commission in November 2012 (Attachments 1a and 1b).
- Completion of the requested break-up of transmission expenditure into three of the key transmission activities of augmentation investment, replacement investment, and maintenance (Attachment 2).

Further information is being compiled for submission to the Commission in the coming weeks on matters raised by the Commission at public hearings with Grid Australia, and other stakeholders during December 2012.

A central question to be resolved appears to be whether or not there is a useful role for incentive regulation in regulating transmission augmentation investment decision making. If there is a role for incentive regulation, then it follows that augmentation investment decision making should be undertaken by 'for profit' businesses (i.e. transmission asset owners) rather than a 'not for profit' body such as a market and system operator.

It was apparent from the public hearing involving Grid Australia (held in Canberra on 6 December) that the Commissioners may not consider that incentive regulation can, or should, be applied to electricity transmission. Factors that appeared to contribute to this position included:

1. The belief that incentive regulation was not practical for large lumpy investments often required for the transmission sector (as distinct from the larger number of smaller investments in the distribution sector).

2. Incentive regulation is not adopted in the United States for electricity transmission.

The pending submission, referred to above, will provide further relevant information and analysis on these matters to the Commission. Most notably, the role of incentive regulation as 'best practice' regulation of transmission in the UK will be explained.

Yours sincerely,

Philip Gall
Acting Chairman, Grid Australia Regulatory Managers Group

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Electricity Networks Regulation

Submission in response to the Productivity Commission Draft Report

18 January 2013

Powerlink Queensland · TransGrid · ElectraNet electricity transmission · Transend · SP AusNet A member of Singapore Power Group

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Attachment 1a – Answers to Questions on Transmission Incentive Regulation Example

This note sets out Grid Australia's responses to questions posed by Peter Varela from the Productivity Commission on an example of a possible incentive regulation arrangement to be applied to electricity transmission investment. The relevant example is set out on page 18 of a Grid Australia submission on Electricity Network Regulation lodged with the Productivity Commission in November 2012 and, for ease of reference, is repeated in Attachment 1b.

1. Context

A key element of Grid Australia's position is that commercial incentives have an important role to play in regulating electricity transmission businesses to achieve efficient transmission service provision. This includes regulators being able to use commercial incentives to encourage efficient transmission investment. Grid Australia understands that this view is shared by specialist industry regulators in Australia (the AEMC and AER) and overseas e.g. the OFGEM in the UK.

However, commercial incentives can only operate where the entity making an investment decision is a commercial (i.e. 'for profit') entity. If investment decisions are undertaken by a 'not for profit' entity, such as a public authority or market and system operator, then commercial incentives cannot be 'part of the mix' in achieving efficient outcomes as these entities are, by their nature, unresponsive to commercial considerations.

In the public hearings it was apparent that the Productivity Commission correctly recognises the different requirements for designing commercial incentives for transmission and distribution.

However, the crucial question appears to be whether or not incentive regulation of transmission augmentation investment is just too difficult to retain in the regulation mix available to the AER.

If there is a reasonable possibility that incentive regulation can, and should, play an effective role in encouraging more efficient transmission augmentation, then the case for these investment decisions remaining with the commercially orientated transmission network owners is compelling. This allocation of responsibility adds to the armoury of regulatory levers available the AER and others to drive efficient outcomes in the transmission sector.

Alternatively, to conclude that transmission augmentation investment decisions should be made by a 'not for profit' body (such as the AEMO) it is necessary to also conclude that there is no meaningful role for commercial incentives in the regulation of transmission augmentation investment.

The evidence does not support such a conclusion.

Experience in the UK, developed over many years, shows that there is a vital role for well-designed commercial incentives in the regulation of transmission investment. In addition, incentive regulation of transmission investment, including augmentations, has been an accepted part of transmission regulation in Australia since the commencement of the National Electricity Market. The debate has been about the form of these incentives rather than about whether or not they should be part of the regulatory mix.

The example in Attachment 1b, which is the subject of the Commission's questions, was provided by Grid Australia to illustrate the reasonable possibility that incentive schemes can be designed to address some of the specific incentive design issues raised by the Commission. It describes a process by which a revenue determination could be adjusted based on actual demand outcomes where these differ from the demand forecasts used in setting the forecast capital expenditure requirements at the beginning of a regulatory control period.

Similar methods have been used in a range of practical regulatory situations to manage potential windfall gains and losses to the regulated business from exogenous factors i.e. factors effectively outside the control of the business. Examples are provided in the more specific responses below.

2. Questions and Responses

Question 1 – Is this [the proposal set out in Attachment 1b] something that Grid Australia has proposed to the AEMC?

The short answer to this question is 'yes'.

Grid Australia members were party to a submission to the AEMC by the Energy Networks Association lodged in December 2011. This submission can be found at: http://www.aemc.gov.au/Media/docs/Energy%20Networks%20Association-715fa3b5-4c38-40c7-a929-8cd21f3da049-0.pdf. This is a very extensive submission covering the wide range of issues before the AEMC at the time.

The relevant part of this submission can be found in Section 4.2.4 of the first expert report on capital expenditure incentives (Attachment B to that submission) in the sub-section titled 'Risk created by the scheme' on page 28 of that expert report. This expressly discusses the matter of exogenous factors (such as changes in demand) in relation to the design of capital expenditure incentive schemes.

Further to this, the criteria ultimately proposed to the AEMC specifically refer to a need for the AER to have regard to exogenous factors in the design of the scheme. This is also mentioned in the following much more recent submission to the AEMC by the Energy Networks Association in October 2012, which can be found at: http://www.aemc.gov.au/Media/docs/Energy-Networks-Association-dee44c03-e993-46ec-a3ce-a1fe6ebb2284-0.PDF. In this regard, please see the incentive design criterion number seven for inclusion in the Rules aimed at dealing with potential windfall gains and losses to regulated network businesses. This can be found on page 57 of this submission and expressly proposes making adjustments to reduce the impact of events that are not within the full control of network service providers (NSPs).

Question 2 – Is there any other document in which this idea is explored in more detail?

In addition to the documents referred to in response to Question 1 the AER is now required to review and develop the capital expenditure incentive arrangements for both electricity distribution and transmission. This is in accordance with the most recent changes in the National Electricity Rules confirmed by the AEMC in late 2012. Accordingly, Grid Australia will almost certainly include this design proposal as part of its wider proposals to the AER for future incentive design arrangements. It is possible that other stakeholders may also make similar proposals as part of this process.

Many of the relevant considerations in developing improved capital investment incentive arrangements are discussed in Section 4.2 on page 22 of the expert report in Attachment B to the ENA submission referred to above and available at: http://www.aemc.gov.au/Media/docs/Energy%20Networks%20Association-715fa3b5-4c38-40c7-a929-8cd21f3da049-0.pdf. This helps show that the matter addressed in the example set out in Attachment 1b is only one aspect of incentive design than needs to be considered.

Other issues include:

- The need for the regulator to ensure that predefined service objectives are not compromised by excessive incentives to minimise costs. This can be achieved in a number of ways, including mandating service outcomes as part of a licence requirement and/or setting complementary service related commercial incentives. The relative strength of these incentives is an important consideration in ensuring that minimising of costs does not come at the expense of service shortfalls.

- Ensuring the rewards for reducing overall capital expenditure are properly balanced with the rewards for achieving efficient deferral of expenditure.

- Recognising that transmission service outcomes, unlike distribution service outcomes, include contributing to the efficient operation of the wholesale electricity market.

The need to address these matters may appear to be complicated. However, significant simplification has been achieved in practice over many years of regulating infrastructure. This involves setting clearly defined service requirements (e.g. via licence conditions or service performance incentive schemes) and using commercial incentives to encourage these to be achieved at least cost.

Question 3 – Has this process been used before either in Australia or overseas?

The particular aspect of capital investment incentive design being addressed in the example in Attachment 1b is to remove, or at least substantially reduce, the potential for windfall gains or losses by the regulated business as a result of factors unrelated to the performance that is being rewarded. The difference between forecast and actual load growth outcomes over a five year regulatory period is but one example of a range of possible exogenous factors.

In this regard it should be noted that price cap regulation (as distinct from revenue cap regulation) is commonly practiced for a range of regulated network businesses including electricity distribution. Price cap regulation inherently adjusts revenues for variations between forecast and actual load growth outcomes.

Other incentive arrangements to deal with windfall gains and losses to regulated businesses arising from exogenous factors have been developed and applied by the Essential Services Commission in Victoria. This has occurred for both gas and electricity network regulation. Grid Australia is also aware of similar techniques being adopted in the past in the UK. These have now evolved in the UK into a comprehensive package of incentive arrangements announced by Ofgem in December 2012. Each of these examples is briefly discussed in turn below.

Victorian Gas Network Regulation Example

The Essential Services Commission (ESC) of Victoria introduced a scheme in 2002 involving ex-post adjustments to the capital and operating expenditure benchmarks used to provide commercial incentives to the regulated gas distribution businesses. The relevant capex benchmarks are set out in the Commission's 2002 Review of Gas Access Arrangements – Final Decision, October, on page 170. The Commission required the businesses to provide a mechanism for adjusting these benchmarks for the actual outturn of the number of new connections that actually occurred during the subsequent regulatory control period.

The 2008 ESC decision – which applied the carryover established in 2002 – is available at: http://www.sp-ausnet.com.au/CA2575630006F222/Lookup/Projects/$file/Gas%20access%20arrangement.pdf. Some of the relevant quotes from this decision are as follows:

From page 573:

13.4 Capital expenditure ECM for the second regulatory period

The ECM provisions require adjustments to be made to the original benchmarks in order to account for differences between forecast and actual work undertaken. Similarly, in calculating the ECM amounts it is necessary to ensure that actual costs reported by the distributors are consistent with the benchmarks – i.e. that they can be compared on a 'like for like' basis. This ensures that the efficiencies achieved by the distributors can be identified and rewarded accordingly.

From page 574:

> In the draft decision the Commission made a number of adjustments to the capital expenditure benchmarks and actual outcomes consistent with the above provisions. Adjustments were made in respect of:
>
> - the number of domestic and non-domestic connections
> - the length of low pressure mains replacement and
> - the number of domestic and non-domestic meter replacements.
>
> Adjusted benchmarks were calculated using the following formula:
>
> Adjustment amount = Actual units completed *minus* forecast units completed *multiplied* by the approved unit rate

UK Electricity Transmission Regulation

During the initial operation of transmission incentive regulation in the UK in the 1990s there was a significant move from coal fired generation to gas fired electricity generation. This was related to the relatively high cost of coal compared with new gas supplies sourced from the North Sea.

At that time the level of capital investment in transmission was significantly impacted by the level of new gas generation connection. The forecast revenue requirements at the beginning of a regulatory control period were sensitive to this variable.

To address this, a mechanism similar to that proposed in Attachment 1b was adopted by the Office of Electricity Regulation (OFFER). However, in this case, the adjustment to the reference revenue path was linked to the outturn level of new gas generation, rather than the outturn load growth. At the time, load growth in the UK was modest and relatively predictable and had modest and relatively predictable impacts on the transmission investment requirements.

As UK incentive regulation continued to evolve these, and other, incentive design features have developed further. On 17 December 2012 OFGEM released its "RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas" paper on "Cost assessment and uncertainty Supporting Document" which can be located at: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/3_RIIOT1_FP_Uncertainty_dec12.pdf.

While the terminology is a bit challenging, due to the differences between Australian and UK terminology for the same concepts, this document does include proposals similar to the example on page 18 of the Grid Australia submission to the Commission (and repeated in Attachment 1b to this note). These include uncertainty funding mechanisms, including volume adjustments, which involve automatic adjustments where outputs differ to the baseline level.

Interestingly, 'uncertainty funding' is also impacted by events defined in the UK transmission licences, or may be activated at certain times during the price control period after further assessment by OFGEM of needs and costs. At face, there appears to be parallels here with ‘pass through’ and ‘contingent project’ mechanisms, which are, currently, part of the Australian arrangements for incentive regulation of electricity transmission.

The other potentially relevant document within the OFGEM package released on 17 December 2012 is: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/2_RIIOT1_FP_OutputsIncentives_dec12.pdf(Outputs, incentives and innovation supporting document). Both of the above mentioned OFGEM documents make a number of references to the strategy documents referred to at: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=77&refer=Networks/Trans/PriceControls/RIIO-T1/ConRes

Attachment 1b – Example from Page 18 of the Grid Australia November 2012 Submission to by the Productivity Commission

Box 1: Possible approach to minimising windfall gains and losses under incentive regulation

In many incentive schemes, the reward or penalty that a regulated business receives for a change in performance is based on the difference between an ex ante forecast of the relevant performance metric and the result that is achieved. This approach is taken in the service target performance incentive schemes and operating expenditure efficiency benefit sharing schemes for both transmission and distribution. It is also implicit where a forecast of capital expenditure is included in the setting of a price or revenue cap.

The gap between the relevant forecasts and outturn results is not a real measure of the change in efficiency resulting from the efforts of the regulated business because factors beyond the control of the business will also affect service outcomes or the required expenditure. Nevertheless, provided the windfall gains and losses arising from the effect of exogenous factors are sufficiently modest and symmetric, this administratively simple measure of the change in efficiency is feasible.

However, transmission augmentation projects can be very large, and their timing critically affected by the forecast of demand, which is largely outside of the control of the transmission businesses. The implications of these factors is that applying a simple incentive scheme to transmission augmentation projects could deliver material windfall gains or losses (depending upon whether demand forecasts turn out to be too high or too low), which explains the preference of some of the consumer representatives for excluding such projects from incentive schemes.

An alternative approach to excluding augmentation projects from an incentive scheme is to attempt to remove the demand-related “windfall” element from the rewards and penalties under the scheme. One possible approach for achieving this outcome would be as follows.

- First, include a forecast of augmentation expenditure in the capital expenditure that is included under the revenue cap that is based upon the best forecasts of demand available at the time. As discussed elsewhere in this submission, converting economically derived standards into a deterministic equivalent makes it more straightforward to link demand and expected capital expenditure needs.

- Secondly, at the end of the regulatory period, re-run the models that were used to forecast augmentation expenditure using the actual demand that was observed over the period. This step could be made easier by the AER generating a number of forecasts of augmentation expenditure during the preceding review, with each scenario corresponding to different forecasts of demand, which is undertaken already by the TNSPs that use a probability-weighted average for capital expenditure across different scenarios for demand.

- Thirdly, calculate the business-induced efficiencies in augmentation expenditure by comparing the actual augmentation expenditure to the adjusted forecast. This would allow the demand-induced "windfall" element to be removed from the measured change in efficiency, while still including (and thereby encouraging) savings in the cost of the project, or savings from being able to defer the project (including through undertaking demand-side measures).

This last step would permit the "windfall" element to be removed from the reward or penalty that may have accrued during the previous regulatory period, as well as permitting this to be excluded from any carry-over of capital-related efficiency benefits into the next regulatory period. It is observed here that while undertaking such a project-by-project adjustment may appear at first sight to be complex or intrusive, the "lumpiness" that characterises projects in the transmission sector makes such a project-by-project adjustment feasible. Moreover, as discussed below, the option would remain to remove particularly large or uncertain projects from the revenue cap and treat them instead as a contingent project.

The approach set out above would require assessment and implementation details to be developed, but would appear to address some of the Commission's concerns. It is noted that developing such a mechanism is within the AER's powers under the new capital expenditure incentive rules that the AEMC has finalised and there other possible design options that could emerge from the AER Guidelines development process to address concerns.

Attachment 2 – 5-year Grid Australia project forecast data

The table below presents Grid Australia's total forecast five-year costs for augmentation, replacement and maintenance projects by size and type of project. Following the table and its accompanying notes are descriptions of five different proposed projects estimated to cost more than $35 million.

Grid Australia consolidated 5-year forecast project costs

Project size	Augmentation		Replacement		Maintenance
	$ million ($2012 or $2012/13)	Number of projects	$ million ($2012 or $2012/13)	Number of projects	$ million ($2012 or $2012/13)
< $0 - < $5 million	93	89	437	536	
$5 million - < $35 million	532	60	1409	178	
> $35 million	999	21	1914	42	
Total	**$1,624m**	**170**	**$3,761m**	**756**	**$1,552m**

Notes:

1. Figures are sums of values for SPAusNet (Victoria), TransGrid (NSW), Powerlink (Queensland), ElectraNet (South Australia) and Transend (Tasmania).
2. Each transmission business's figures were provided for different five-year periods falling between 2012 and 2019, depending on what stage of its regulatory control period each TNSP is at.
3. Augmentation figures include prescribed costs for augmentations, connections and easements.
4. Augmentation figures do not include data for Victoria, as AEMO plans and directs network augmentation in that region.
5. Replacement projects are classified differently across TNSPs, impacting the project number count (for example, replacement across the network of a particular type of equipment could be considered as one project by one TNSP, but as many different projects by another).
6. Maintenance figures are direct costs only, and may not include costs such as WH&S, business support, corporate costs, asset management planning costs, customer management, grid planning, project initiation, regulation and compliance, system modelling and planning etc.

Examples of projects greater than $35 million

Redevelopment of West Melbourne Terminal Station at approximately $150 million (SP AusNet, Victoria)

The West Melbourne Terminal Station (WMTS) is one of the three terminal stations in Melbourne supplying the CBD plus the surrounding residential, commercial and industrial western area. The redevelopment of WMTS is driven by reliability considerations, load criticality and asset performance. Along with RTS (discussed below), the rebuild of WMTS will secure supply to the CBD and inner Melbourne.

The planned rebuild will replace end-of-life assets with modern, safe and more compact equivalents including: replacing the 220 kV switchyard with indoor GIS; replacing the 220/66 kV and 220/22 kV transformers; and replacing protection and control systems.

Redevelopment of Richmond Terminal Station at approximately $150 million (SP AusNet, Victoria)

Richmond Terminal Station (RTS) provides supply to the Eastern Central Business District and inner suburban areas in the inner east and south-east of metropolitan Melbourne. Three of the four existing transformers have been identified as having some of the highest risk of failure of any transformers in the SP AusNet network. The terminal station's present 220 kV switching arrangement presents a supply risk and there is no space to increase the station capacity or to improve the switching configuration within the existing arrangement. It is therefore necessary for RTS to be rebuilt to secure supply to the CBD and inner Melbourne.

The existing 220 kV switchyard will be replaced with indoor gas insulated switchgear equipment that provides independent switching for all lines and transformers. Replacement of ageing 150 MVA 220/66 kV transformers with larger 225 MVA units is also required to create more space to facilitate the refurbishment and provide for further capacity expansion. This will maintain total N-1 capacity at current levels. Significant replacement of protection, control, metering and communications equipment is also required.

CityGrid project estimated at $358 million (TransGrid, New South Wales)

The CitiGrid project is to install a new 330 kV supply to the Sydney CBD. The primary drivers for this project are replacement of capacity due to thermal issues on an existing TransGrid 330 kV supply and replacement of Ausgrid 132 kV cables that are reaching their end of life. However, demand forecasts for the Sydney CBD are also being taken into account to ensure that the capacity installed under the project providers the most overall economically efficient solution. Therefore, although it has been included in Grid Australia's replacement project figures, it may meet both replacement and augmentation needs.

Palmerston to Avoca 110 kV Transmission Line Augmentation valued at $36 million (Transend, Tasmania)

The project involves the installation of a second 110 kV transmission circuit primarily driven by the requirements of the Tasmanian ESI planning regulations for load associated with Avoca Substation. Joint planning with Tasmania's distribution network service provider is underway and an alternative option that better satisfies the regulatory investment test for transmission (RIT-T) may yet be identified.