grid australia
BACKBONE OF THE NEM

1 February 2013

Productivity Commission
GPO Box 1428
Canberra City ACT 2601

Attention: Commissioners Phillip Weickhardt and Wendy Craik

Via email: electricity@pc.gov.au

Dear Commissioners

Electricity Network Regulation Inquiry

I am writing with reference to the public hearings conducted as part of the abovementioned Inquiry, in general, and, more particularly, the public hearings on 6 December 2012 and 10 December 2012 involving Grid Australia and the Australian Energy Market Operator respectively.

Grid Australia appreciated the opportunity to present to the hearing and the constructive manner in which the Commissioners tested the evidence provided. In the attached submission, Grid Australia considers key issues raised during the hearings, namely:

- The interpretation of overseas evidence regarding the scope for incentive regulation in relation to transmission investment;
- The application of incentive regulation to more uncertain transmission augmentation projects;
- The possibility of making all transmission augmentation investments above a certain size 'contingent projects'; and
- Which parties should be responsible for making transmission investment decisions.

Two expert reports are also provided, considering economic regulation of electricity transmission networks in the United States and the United Kingdom.

The submission supports the conclusion that the long term interests of electricity consumers are best served if transmission system owners retain ultimate responsibility for transmission augmentation investments.

Yours sincerely

Rainer Korte
Chairman
Grid Australia Regulatory Managers Group

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Productivity Commission Inquiry into Electricity Networks Regulatory Frameworks

Submission in response to matters raised in the December 2012 public hearings

January 2013

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1 Overview

The purpose of this supplementary submission to the Productivity Commission's Inquiry into Electricity Networks Regulatory Frameworks is to provide further information on matters raised at the public hearings held in Canberra on 6 December 2012 and 10 December 2012, involving Grid Australia and the Australian Energy Market Operator (AEMO) respectively. Grid Australia, representing the transmission network businesses in the National Electricity Market[1] (NEM), hopes that this submission will help inform the Commission as it develops its final report in relation to this Inquiry.

The key matters raised at the hearings which are now addressed in this submission are the:

- Interpretation of overseas evidence regarding the scope for incentive regulation in relation to transmission investment (considered in Section 2 below);
- Application of incentive regulation to more uncertain transmission augmentation projects (considered in Section 3 below);
- Possibility of making all transmission augmentation investments above a certain size 'contingent projects' (considered in Section 4 below); and
- Best choice of parties to be responsible for making transmission investment decisions (considered in Section 5 below).

Also included with this submission are two reports from experts in the field of economic regulation of electricity networks. The first of these is from NERA Economic Consulting setting out further information on electricity network regulation in the United States, including the role of history in determining the form of that regulation. The second report is from PricewaterhouseCoopers (PwC) explaining how incentive regulation of transmission in the United Kingdom (UK) addresses some of the concerns raised by the Commission during the current Inquiry.

The further evidence provided in this submission, and expert reports, reinforces Grid Australia's position that the long term interests of electricity consumers are best served if transmission system owners retain ultimate responsibility for all transmission augmentation investments. Grid Australia's position is consistent with the application of the most recent international developments in transmission incentive regulation of transmission services, such as those applied in the UK.

1 Powerlink Queensland, ElectraNet, TransGrid, SP AusNet, and Transend Networks.

Consistent with current best practice regulation the evidence also points to a possible enhanced role for the Australian style transmission 'contingent' project. However, the nature and role of this mechanism is most appropriately left to the economic regulator to develop. In Australia this responsibility rests with the Australian Energy Regulator (AER), as set out in the National Electricity Law and Rules.

2 Interpreting overseas evidence

At the public hearing on 6 December the Commission observed:

> *"I accept the fact that your proposed regime and the AEMC's regime is a better regime than the current status quo but given all those concerns, do you not see that some of the moves people have made internationally to involve not for profit planners have some value in the Australian environment where ironically is the NERA report that you attach seems to indicate that it's not just the Victorians who, for all the reasons I have already mentioned, have used not-for-profit planners and the world hasn't ended, the risks of who's at fault doesn't seem to have pre-occupied the North Americans or the others who have done this. You're sort of painting this a black and white picture that it just cannot work when you've got a not-for-profit planner in place and yet internationally that experience seems relevant."*[2]

It is true that the arrangements in the United States (US) can involve a 'not for profit' planner determining which of the major transmission augmentation investments should be undertaken. It should be noted that this role is typically limited to the largest projects required to meet pre-determined reliability standards.

However, Grid Australia argues that the US arrangements are unlikely to be the most effective in delivering efficient outcomes. The ability to fully utilise incentive regulation is one of a number of important reasons for this.

A regime that allows the regulator to include incentive regulation of large projects in its 'tool kit' for regulating transmission services is superior to one that does not. Incentive regulation requires the decision making body to be responsive to commercial incentives and it logically follows that this can only be achieved in a regime where a commercial (i.e. for profit) entity makes the investment decisions.

The reasons why the United States has not adopted incentive regulation, also known as performance based regulation or PBR, are more about history than deliberate policy design to achieve the best possible outcomes. As NERA points out:

> *"… in general, the reasons for the limited existing examples of incentive regulation in either transmission or distribution are mostly historical, rather than*

2 "Transcript of proceedings at Canberra on Thursday, 6 December 2012", Australian Government Productivity Commission, page 297, viewed on 30 January 2013, http://www.pc.gov.au/__data/assets/pdf_file/0018/121158/20121206-electricity-canberra-transcript.pdf. .

> *a result of conscious policy decisions on the merits of applying a PBR approach versus COS regulation".*[3]

Indeed, this is such a strong driver in the US that there has been very limited adoption of incentive based regulation in electricity distribution, notwithstanding the Productivity Commission recognising the important role this can play in electricity distribution regulation. As NERA says:

> *"The lack of pre-disposition to incentive regulation in the US can be clearly seen from its underdevelopment in the electricity distribution sector, in contrast to other countries such as the UK and Australia where incentive regulation does apply. A few utilities in New York and other states decided to adopt a PBR plan for unbundled distribution tariffs in early 2000s, but these plans were later abandoned."*[4]

The NERA report also demonstrates the crucial role of legal precedent in the US, rather than express policy development, as follows:

> *"The regulatory principles that commissions follow when setting allowed rates of return on assets, take into account the level of risk that the utility business faces. Legal precedent can be found in two key U.S. Supreme Court decisions, known as the Hope*[5] *case [1944] and the Bluefield decision*[6] *[1923]."*[7]

A key element of this history, as it relates to electricity transmission, has already been discussed in earlier submissions. In particular an earlier report prepared by NERA[8] and provided to the Commission points out:

> *"In the US there continues to be a high degree of common ownership between transmission and other electricity sector activities, including generation and electricity retailing, albeit that in some regions they are unbundled into affiliate corporations. This is in contrast to the industry structure in Australia, where transmission has been unbundled into separate, for profit entities. The continued vertical ownership between transmission and generation interests was a key factor leading to the introduction of the ISO/RTO model in the US. The introduction of an independent party to operate and plan the network enabled the restructuring of the sector (and in particular open-access to the transmission networks) to be achieved without*

3 "A review of electricity network regulation in the US", Amparo Nieto, Senior Consultant, NERA Economic Consulting, 30 January 2013, p. 1.

4 Nieto, NERA, 2013p. 5.

5 "Federal Power Commission vs. Hope Natural Gas Company", 320 U.S. 591 (1944).

6 "Bluefield Water Works and Improvement Company vs. Public Service Commission", 262 U.S. 679 (1923).

7 Nieto, NERA, 2013, p. 3.

8 "US Transmission Planning Arrangements – Competitive Procurement and Independent Planner Model" Whitfield, Nieto, Orlandi, NERA, 21 November 2012, p. 5.

the requirement for divestment of transmission ownership from other utility activities.”

Furthermore, as the NERA report points out, the historical establishment of ‘not for profit’ independent system operators (ISOs) and regional transmission organisations (RTOs) with authority to determine required investments, of itself, mitigates the use of incentive regulation (or PBR as it is referred to in the US) in that country. In this regard the report states:

“The potential for adopting a PBR mechanism for transmission is more limited in the case of restructured states, where not-for-profit ISOs and RTOs (as opposed to for-profit transmission companies, or “Transcos”)[9] *have assumed the main planning and operational responsibilities, including decision making authority over which major transmission investments will be undertaken. As a consequence of their not-for-profit status, it is not possible to introduce explicit financial incentives on these bodies in relation to transmission investment.”*[10]

The UK, on the other hand, was very much more a product of deliberate, and relatively more recent, policy design. As pointed out in the PwC report:

“Economic regulation in the UK (which began as a critical element to the privatisation of the formerly state owned telecommunications, water, gas and electricity assets in the 1980s and 1990s) commenced with a “blank sheet of paper” and so was able to learn from the lessons from the US practice of utility regulation, most notably the perceived poor incentive properties and consequent cost and complexity of traditional US utility regulation.”[11]

Grid Australia’s position is that the arrangements operating in the UK encourage profit motivated firms to find the most efficient way of co-ordinating the various inputs of ‘production’ to achieve the required outputs. This includes the capital investment ‘input’, among others. While this might be ‘second best’ compared with a competitive market place to achieve the same outcomes, it is superior to what is, effectively, public sector (or inner Government) style investment decision making by a ‘not for profit’ body in Victoria and in many US jurisdictions.

The attached PwC report expresses this position as follows:

“The rationale for applying incentive regulation is that it is believed to deliver better outcomes for society than the alternative of a regulatory or other central planning type authority being involved in a range of operational decisions for

9 A proposal for a regional for-profit Transco, “Alliance RTO” in the Midwest ISO, was filed before FERC in June 1999. Although FERC initially approved the Alliance companies’ development plan, it eventually rejected the plan, finding that the Alliance RTO lacked sufficient geographic scope to exist as a stand-alone entity.

10 Nieto, NERA, 2013, p. 5.

11 “Design and implementation of incentive regulation for electricity transmission businesses”, PricewaterhouseCoopers (PwC), 29 January 2013, p. 3.

> *which it may be poorly placed. Thus, by providing regulated businesses with a commercial incentive to act in a socially desirable manner, the full private information and expertise of the regulated entity would be expected to be harnessed to find ways to achieve the relevant objective, and simultaneously the process of regulation is simplified."*[12]

It is also clear from the PwC report that this view is shared by 'designers' of the UK transmission arrangements.

> *"While it may seem like a "leap of faith" that incentive regulation may deliver better outcomes than a central planning model, the original pressure for incentive regulation arose from a very real dissatisfaction with the traditional form of utility regulation in North America, where the incentives on regulated businesses for desirable outcomes were weak, and as a consequence, regulatory processes were frequent and unnecessarily complex and broad in their coverage. These and other issues with the traditional form of regulation in the US were spelled out in a persuasive report by Professor Littlechild for the UK government prior to the latter privatising its utility infrastructure in the 1980s, and led to the latter embarking on a conscious decision to implement an incentive regulation regime for its newly privatised industries".*[13]

Similarly, it is apparent from the AEMC's Transmission Frameworks Review that the AEMC shares this view.

3 Complexity of incentive regulation for transmission augmentation

During the hearings the Commission made a number of observations on the complexity of transmission regulation including the following:

> *"So transmission is complicated. You've got inter-regional effects, you've got effects of distribution networks, you've got the risks of under-investment and you've got very large, lumpy investments which don't allow the regulator to really with confidence set incentive regulations that they're confident about. In fact, the AER themselves on Monday said they have real concerns about incentive regulation and the incentive schemes in transmission working effectively."*[14]

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12 PwC, 2013, p. 4.

13 PwC, 2013, p. 4.

14 "Transcript of proceedings at Canberra on Thursday, 6 December 2012", Productivity Commission, page 297,

And:

> *"At the moment, an ex ante revenue allowance with forecasts of expenditure five years down the track gives all sorts of risks of not necessarily managing expenditure tightly and there are all sorts of unknowns in terms of the cost of the goods, the exchange rate that will influence the capital cost of projects. The regulator has got great difficulty in approving a sensible level of ex ante expenditure for a transmission company, as indeed I suspect the transmission company have."*[15]

Grid Australia recognises that incentive regulation of transmission, including transmission investment decision making, can be complex. The reasons provided by the Commission help illustrate this point.

However, Grid Australia, like the UK regulator Ofgem and the AEMC, consider these issues can be addressed with thoughtful incentive design operating in conjunction with appropriate administrative arrangements. The issues raised are not necessarily more challenging than in other areas of infrastructure regulation. Nor has the case been made by the Commission that incentive design for transmission investments is so challenging that investment decisions should, therefore, be subjected to public service style decision making.

The PwC report identifies and shows how the UK regulator addresses many of the issues raised by the Commission.

For example, in relation to concerns that service outcomes might be undermined (e.g. as a result of underinvestment), PwC notes that:

> *"The incentive regulation framework in the UK, upon which the Australian regime is based, is a regime that is focused on powerful incentives to reduce costs combined with a strong emphasis on defining the outputs (or outcomes) expected by regulated utilities and holding the utilities to account for the delivery of those outcomes, including through financial incentives."*[16]

In relation to concerns about changing circumstances that impact on an ex-ante forecast PwC notes that:

> *"Ofgem addresses the potential problem of windfall gains or losses by setting, or changing, revenue allowance depending on the certainty, or realisation, of certain cost drivers. Those costs that are more certain will form part of a baseline allowance and be subject to the full range of financial incentives (these are particularly high powered in the UK regime). However, the revenue allowance can vary on the basis of volume drivers that relate to changes in the*

15 "Transcript of proceedings at Canberra on Thursday, 6 December 2012", Australian Government Productivity Commission, page 299.

16 PwC, 2013, p. 3.

demand of customer or generation connections or the need for network capacity improvements. A mechanism similar to the contingent projects mechanism in the NEM also applies for material reinforcements of the transmission network. The extent that these measures retain the full range of financial incentives is dependent on the specific mechanisms applied to adjusting the revenue allowance."[17]

Further evidence to this effect was provided in the Grid Australia submission lodged with the Commission on 18 January 2012 in response to questions on these matters from Commission staff. This included specific examples of how uncertainty in capital expenditure forecasts had been addressed in practice, including in gas network regulation in Victoria.

From the references to the AER by the Commission above it does not appear that the AER is saying that it is 'not up to the task' on these issues. Rather, it appears that the AER may be saying simply that it is a challenging area of regulation. In any event, the ability (or otherwise) of the AER to carry out its functions (similar to those already delivered by Ofgem, and past Australian jurisdictional regulators) should not be the primary consideration in deciding the best policy direction on this particular matter.

4 Making large transmission augmentation investments 'contingent'

The Commission has identified some of the challenges in designing incentives to regulate transmission investment. The 'contingent' project regime is one of a number of design features available to the AER to manage these challenges.

The Commission has also raised the possibility that certain size projects should become, by default, contingent projects. This was proposed by the Commission at the public hearings as follows:

"given the difficulty of predicting exactly when investments will come, the lead times in transmission and all the difficulties of developing incentive regulation for projects that are out in the future, why wouldn't you make projects above a certain threshold - all projects above a certain threshold - effectively contingent projects?"[18]

At the public hearing Grid Australia agreed that this proposal was worthy of further consideration, albeit cautiously. Ideally, such consideration should be undertaken by the Australian Energy Regulator when it develops its Capital Expenditure Incentive Guidelines for incentive regulation for transmission, as is required by recent amendments to the National Electricity Rules (NER clause 6A 2.3 (a) (1)).

17 PwC, 2013, p. 3.

18 "Transcript of proceedings at Canberra on Thursday, 6 December 2012", Productivity Commission, page 303,

With this in mind, care needs to be taken in recommending a policy of mandating all augmentation projects above a certain cost to be treated as contingent projects. To constrain the economic regulator on this specific aspect of incentive design does not appear to be sound policy. Two reasons for this are that:

1. It would undermine the discretion of the AER to design and develop the incentive regimes in accordance with the principles in the Law and Rules, including adapting incentive schemes in response to evolving practice and experience.
2. Not all large projects are so uncertain that this approach is the best approach, and the circumstances are therefore relevant in deciding the appropriate incentives. For example, changes in timing of demand driven projects, even large projects, may be better addressed using different mechanisms similar to those proposed in the Grid Australia submission to the Commission in November 2012 and those used by Ofgem as described in the attached PwC paper.

A possible alternative to the mandated use of contingent projects is for the Productivity Commission to recommend that the AER give consideration to a broadened scope for use of the contingent project mechanism when developing its incentive frameworks for transmission.

5 Responsibility for transmission augmentation decisions

Grid Australia notes that there are a number of very sound policy and design reasons for the responsibility for transmission augmentation investment decisions remaining with the transmission system owners.

While this submission focuses on the benefits of enabling the full scope of incentive regulation of transmission to be applied, it is worth re-iterating the other important benefits of this allocation of responsibility set out in previous submissions and before the public hearings. These include:

1. better integration of the functions required to deliver transmission service outcomes;
2. better integration of transmission arrangements with the wider market design; and
3. enhanced independent expert oversight of transmission investment decisions.

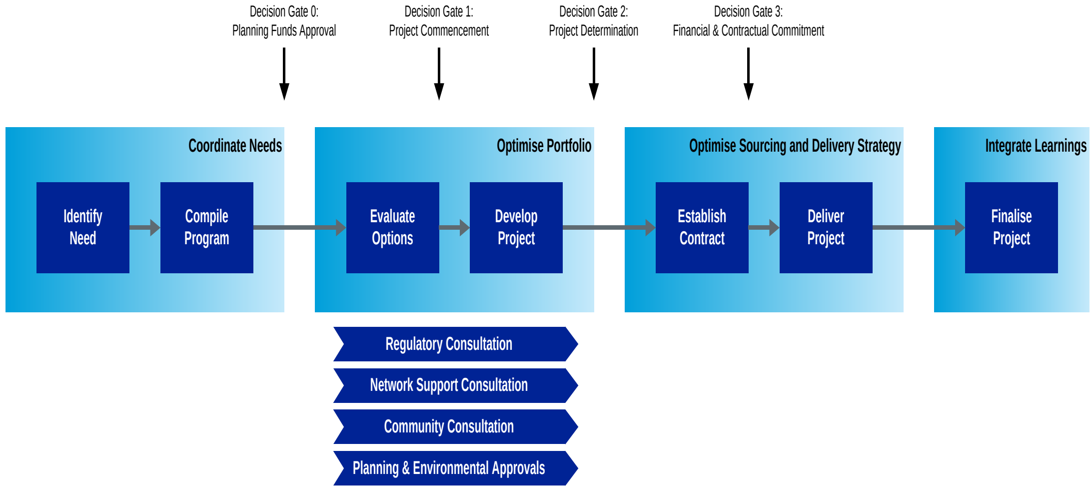
On the better integration of transmission functions (point 1 above) Grid Australia has recently provided the Commission (on 18 January 2013) with detailed data on the overall spending on the interrelated activities of augmentation investment, replacement investment, and operating and maintenance.

Further to this, it is worth noting that where the transmission system owner has responsibility for expenditure decisions on all of these matters, augmentation investment decisions can be undertaken to optimise overall asset life cycle costs.

Good electricity industry practice is reflected in internationally recognised asset management frameworks, such as PAS55 (soon to be superseded by ISO 55000) and others.

Consistent with these frameworks, and across their entire asset portfolio, transmission system owners, that also have augmentation investment responsibilities, consider synergies, and optimise the portfolio over both augmentation and replacement needs. This can be seen from TransGrid's Network Investment Process, as shown in Figure 1 below.

Figure 1 TransGrid's Network Investment Process



Synergies are achieved throughout this process as follows:

1. As needs are identified and compiled into the forward program, they are coordinated with all other needs across both augmentation and asset replacement/renewal. This is to ensure that options are considered across related needs, rather than separately.
2. During the stages of option evaluation and project development, the portfolio is optimised by considering dependencies between projects and evaluating options in the context of related needs.
3. In the process of establishing contracts and delivering projects, the sourcing and delivery strategies are optimised to deliver the portfolio at the most efficient cost.
4. Upon completion of the project, the step of finalising the project includes a review of key lessons to inform process improvement.

At the public hearing in Canberra on 10 December AEMO said that the approach described above does, or can, occur systematically when augmentation investment decisions are undertaken by a different body to that responsible for network management. To some extent this may be possible. However, the difficulty in assigning risk between the parties makes true integration problematic. Grid Australia does not find AEMO's comments to the Commission on this matter[19]convincing.

In relation to better integration with the National Electricity Market (point 2 above), leaving augmentation investment decision making with the transmission system owners also overcomes the problems experienced in the processing of generator connections that occur in Victoria. These problems are a direct result of always having at least two parties involved in providing assets required to facilitate connections. In Victoria these are SP AusNet providing dedicated connection services and AEMO arranging the associated shared transmission augmentations.

Grid Australia is aware of a recent late submission on this matter from AEMO to the AEMC. As yet it is not clear to Grid Australia how this latest proposal addresses the fundamental structural problem in Victoria of requiring both AEMO and SPAusnet to be contractual parties to all new connection arrangements.

On the need to provide independent expert oversight of transmission investment proposal (point 3 above) there are clear benefits in having AEMO provide an independent expert advisory role to the AER on transmission investment decisions. Among other matters, it enables the AER to harness the specialist technical knowledge that does reside within AEMO. However, this can only occur where AEMO itself is not responsible for investment decision making.

6 Conclusion

Grid Australia has provided further information and expert reports in this submission on matters raised in the Commission's public hearings. This is intended to help inform the Commission as it develops its final report in relation to this inquiry.

The evidence provided shows that best practice transmission regulation includes an important role for incentive regulation, including in relation to the regulation of transmission augmentation investments. Accordingly, augmentation investment decision making should remain with profit motivated transmission system owners.

There are other benefits of this allocation of ultimate responsibility for these investment decisions to the transmission system owners. The accountability for transmission service outcomes is clearer and the market and system operator is able to fully undertake an independent expert advisory role to the economic regulator, i.e. AEMO can assist the AER in the Australian context.

19 "Transcript of proceedings at Canberra on Monday, 10 December 2012", Australian Government Productivity Commission, page 412, viewed on 30 January 2013, http://www.pc.gov.au/__data/assets/pdf_file/0018/121158/20121206-electricity-canberra-transcript.pdf.

In relation to the proposal to mandate that all projects above a certain size are regulated as ‘contingent’ projects, this is a matter that should be considered by the Australian Energy Regulator as it develops its Capital Expenditure Incentive Guidelines for incentive regulation of transmission.

Attachments to this Submission

1. "A Review of Electricity Network Regulation in the US", Amparo Nieto, NERA, 30 January 2013

2. Resume of Amparo Nieto

3. "Design and Implementation of Incentive Regulation for Transmission Businesses", Jeff Balchin and Scott Stacey, PricewaterhouseCoopers, 29 January 2013.

4. Resumes of Jeff Balchin and Scott Stacey

NERA
Economic Consulting

A Review of Electricity Network Regulation in the US

Amparo Nieto

January 30, 2013

1. Introduction

This note has been prepared by Amparo Nieto, a Senior Consultant at NERA Economic Consulting (NERA) at the request of Grid Australia. Grid Australia has asked for an overview of the approach adopted for the regulation of electricity network activities in the US, along with a discussion of the main factors that have historically limited the use to date of incentive-based approaches, known in the US as Performance Based Regulation (PBR) plans.

This note is structured as follows: Section 2 provides relevant background on the range of ownership structures of electricity network businesses in the US. Section 3 discusses the main elements of regulation for electricity networks in the US, highlighting the predominant reliance on traditional Cost of Service (COS) methods. Section 4 highlights the limited adoption of PBR, involving formal price or revenue caps plans, for electricity networks in the US, including distribution activities. Section 5 summarizes the key conclusion of the review, which is that, in general, the reasons for the limited existing examples of incentive regulation in either transmission or distribution are largely historical, rather than a result of conscious policy decisions on the merits of applying a PBR approach versus COS regulation.

2. Structure of Electricity Network Companies and Regulatory Bodies in the US

About seventy five percent of electricity distribution assets in the US are owned by private utilities (a.k.a. "Investor Owned Utilities", or IOUs). The remainder of the distribution infrastructure is owned by municipal utilities (governed by the local city council), public power districts (governed by a board elected by voters within the service territory) and cooperatives (nonprofit entities mostly in rural areas, governed by a board elected by their own customers). All private distribution companies in the US are subject to the jurisdiction of state Public Utility Commissions (PUCs).

Transmission, which is mostly an *inter-state* activity, is largely regulated by the Federal Energy Regulatory Commission (FERC), except in Texas (ERCOT), Hawaii, and Alaska. FERC is not allowed to regulate distribution because the U.S. Constitution allows federal intrusion into private economic activity only where interstate commerce is involved, which is nowadays the case of the bulk of transmission.[1] The legislation that first influenced the regulation of interstate transmission networks was the Energy Policy Act of 1992, and it has evolved over time with the EPACT 1995, FERC Orders 888, 889 and 2000, FERC Orders 679 and more recently, FERC Order 1000. There continues to be some overlap between federal and state regulation however, with regard to local transmission. State regulators exercise their rights and responsibilities mostly through siting approval and the determination of transmission revenue requirement to be collected from the transmission owner's retail customers.

The level of vertical integration of the IOUs varies across states. In non-restructured states, private vertically-integrated IOUs own and operate generation, transmission and distribution assets. In the states that underwent restructuring (e.g., California, New York, New England, New Jersey, Maryland, Pennsylvania, Texas), FERC introduced the figure of voluntary, non-for-profit organizations namely a regional Independent System Operator (ISO), or Regional Transmission Organization (RTO), to plan and operate the transmission system.[2] This enabled open access to the transmission networks without the requirement for divestment of transmission assets. The incumbent IOUs in restructured states typically own transmission and distribution lines, but either have divested all of their generation resources (e.g., California) or have undertaken legal unbundling of generation and network functions. In Order 888, the FERC took a non-intrusive alternative to requiring the divestiture of generation or transmission assets, by requiring only functional unbundling. Likewise, FERC Order 2000 did not explicitly require ISOs or RTOs to have a non-profit structure. In all cases, however, the operation of the transmission infrastructure was required to be placed in the hands of ISOs or RTOs.[3]

[1] Historically, transmission assets were mostly owned by vertically-integrated firms and state commissions regulated both transmission and distribution.

[2] ISOs are also tasked with management of congestion on real time basis and dispatch of energy resources following a security-constrained, bid-based procedure.

[3] In the Midwest ISO, existing IOUs were not required to divest their generation assets, but their transmission lines are subject to RTO operational control.

3. PREDOMINANT REGULATORY APPROACH IN THE US: COST OF SERVICE REGULATION

The long-standing regulatory framework in the US for both electricity distribution and electricity transmission activities, either at the FERC or the state level, is Cost of Service (COS), or Rate of Return (ROR) regulation.

Under a COS framework, decisions on the level of transmission and distribution tariffs are made through formal regulatory proceedings at the time of major rate cases. A key role of the regulator during a rate case (or tariff review) is to perform prudence reviews of the costs of the regulated company. The regulator will approve those expenses that are deemed to be "prudently incurred" and will ask the utility to demonstrate that past investments remain "used and useful". The regulator then calculates the revenue requirement for the distribution (or transmission) utility, for a given 'test year', which may be historical, or a future year. When setting allowed rates of return on distribution assets the regulator takes into account the level of risk that the utility business faces. Legal precedent influencing the current regulatory principles in ratemaking can be found in two key U.S. Supreme Court decisions, known as the Hope[4] case and the Bluefield decision[5]. Factors that were considered critical in those cases included financial integrity, balancing of the investor and consumer interests, and ability of the utility to attract capital. In addition to allowing the utility to recover the prudent level of operating costs and depreciation (amortization of capital costs), tariffs must allow for a reasonable rate of return.

Once the allowed rate of return on equity (ROE) and overall revenue requirement are determined, the regulator approves allocation of the revenue requirement to customer classes and tariffs sufficient to recover that amount. These tariffs are valid until the next rate case. A review of transmission or distribution rates can be requested either by the regulated company, when a change in circumstances clearly causes the company's rate of return to reach a level that is unacceptably low, or by the regulator itself, when a third party complains that utilities are earning an unacceptably high rate of return.

In practice, the average interval between general rate cases is between three to five years, but in some cases it may take longer. The fact that electricity tariff reviews take place relatively infrequently is sometimes driven by the fact that they represent a lengthy and involved process (typically not shorter than six months). The existence of informal regulatory lags of several years means that the company bears the risks (if costs increase) and savings (if costs decrease) between major rate cases. The risk to the utility tends to be lower than under a formal incentive scheme, since the utility has the right to request a tariff review at any given time. The regulator may

[4] "Federal Power Commission vs. Hope Natural Gas Company", 320 U.S. 591 (1944).

[5] "Bluefield Water Works and Improvement Company vs. Public Service Commission", 262 U.S. 679 (1923).

request a tariff review when costs of service are lower than anticipated, but there may be a lag since the level of above-normal profit is detected and the time when the rate case takes place.[6] As a result it has been argued that the COS regulation adopted for both electricity transmission and distribution implicitly includes some incentives for cost containment.

Some state regulators do offer explicit incentives to utilities within the traditional COS regulatory framework. US regulators typically set specific policies to encourage utilities to pursue cost-effective energy efficiency measures or demand side management (DSM). Under a DSM incentive mechanism, the regulator establishes an energy reduction target and the utility incurs a penalty if the DSM-related energy savings fall below a specific percentage of the target for the year. If the utility exceeds the target energy savings, it receives a credit that can be used to offset potential DSM-related penalties in subsequent years.

4. HISTORICAL FOCUS ON COSTS HAS LIMITED THE ADOPTION OF INCENTIVE REGULATION

In the late 1980s and early 1990s, as wholesale competition began expanding in the US electricity industry, some state regulators began to consider shifting to incentive regulation or PBR, as an alternative to COS regulation. The idea was that PBR would further weaken the link between the vertically-integrated utility's regulated prices and its costs. However, by the mid- to late-90s, the initial interest in PBR diminished and the focus shifted with the adoption of the so-called 'rate freeze periods' upon the introduction of wholesale energy markets and vertical unbundling. The incumbent utilities' bundled electricity rates in California, Arizona, New York, Idaho, Illinois and other states were capped at existing levels, typically for a period of 10 years, as part of restructuring transitional plans intended to protect the incumbent utilities' entitlements to recover stranded costs.[7] As utilities came out of the rate freeze, in early to mid-2000s, the majority of state regulators turned again to traditional COS regulation. Severe deviations between market costs and electricity rates during the rate freeze period largely drove the preference for returning to COS regulation following the end of the rate freeze. In general, the reasons for the limited existing examples of incentive regulation in either transmission or distribution are largely historical, rather than a result of conscious policy decisions on the merits of applying a PBR approach versus COS regulation.

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[6] There are also opportunities for utilities to request issue-specific filings between rate cases. The scope of these single-case filings is much more limited than under a general rate case, and they are typically triggered when a utility decides to offer new services to customers on an optional basis (e.g., a new interruptible rate), or upon specific changes in accounting policies or tax schedules.

[7] Stranded assets generally refer to the present value of assets and contractual obligations in excess of market value that electric firms may face upon industry restructuring and/or implementation of competitive markets for generation.

The lack of pre-disposition to incentive regulation in the US can be clearly seen from its underdevelopment in the electricity distribution sector, in contrast to other countries such as the UK and Australia where incentive regulation does apply. A few utilities in New York and other states decided to adopt a PBR plan for unbundled distribution tariffs in early 2000s, but many of these plans were later abandoned. Currently only 6 out of the 50 states have a PBR mechanism, involving revenue or price caps for periods of a fixed duration. Two of these states, Oregon and Nevada, include a PBR mechanism applied to their bundled power service rates. The other four states (California, Maine, Massachusetts and Oklahoma), have a formal PBR plan for unbundled distribution. Annex 1 summarizes the main elements of these unbundled distribution PBR plans. The remaining 44 states all adopt a COS approach to the regulation of electricity distribution activities.

COS regulation is also the norm for electricity transmission in the US. There are no examples of price or revenue cap formulae for electricity transmission rates. The potential for adopting a PBR mechanism for transmission is more limited in the case of restructured states, where not-for-profit ISOs and RTOs (as opposed to for-profit transmission companies, or “Transcos”)[8] have assumed the main planning and operational responsibilities, including decision making authority over which major transmission investments will be undertaken. As a consequence of their not-for-profit status, it is not possible to introduce explicit financial incentives on these bodies in relation to transmission investment. However, even in the case of transmission owners, who still influence the level of transmission investments, there are not currently PBR mechanisms in place.

Transmission planning by RTOs/ISOs in the US to date has largely followed a ‘project-sponsored’ approach. Under this approach, incumbent transmission owners or merchant developers can take a proactive role in presenting the ISO/RTO with a potential project. Transmission owners have a particular interest in the local transmission planning process, given their requirement to serve their native load. In 2006, FERC introduced a form of ‘incentives’ under Order No. 679 and 679-A.[9] Specifically, FERC adopted ROE incentives, provided through case-by-case determinations, still within the context of COS regulation. These incentives allow certain qualifying transmission projects which are demonstrated to solve reliability or solve congestion, to be assigned a higher ROE (the so-called “ROE adders”) when calculating the revenue requirement to be recovered

[8] A proposal for a regional for-profit Transco, “Alliance RTO” in the Midwest ISO, was filed before FERC in June 1999. Although FERC initially approved the Alliance companies’ development plan, it eventually rejected the plan, finding that the Alliance RTO lacked sufficient geographic scope to exist as a stand-alone entity

[9] *Promoting Transmission Investment through* Pricing Reform, Order No. 679, 71 FR 43294 (Jul. 31, 2006). These were implemented as a response to the directives in section 1241 of the Energy Policy Act of 2005, which added a new section 219 to the Federal Power Act (FPA).

under transmission owners' open access tariffs.[10] One of the goals of ROE adders was to attract new investment in transmission facilities by ensuring higher certainty of cost recovery to transmission developers, associated with perceived potential risks and challenges in development and completion of the project which may not be accounted for in the base ROE. Outside of these initiatives, there continue to be no formal price or revenue cap periods applied to transmission.

5. CONCLUSIONS

Despite major restructuring changes in the US energy industry, the core of transmission and distribution regulatory approaches in the US has changed little over the last decades. The regulatory approaches on a federal and state level remain largely influenced by historical legal arguments that support case-by-case determinations of reasonable rate of returns on equity and prudent level of costs for private firms. Historical attempts by regulators to introduce formal PBR mechanisms – in the form of formal price or revenue caps– to regulate electricity networks have been timid and most of the earlier plans for distribution were quickly abandoned.

For the most part, the US continues to embrace the traditional COS regulatory approach, where the regulator is tasked with ensuring that the actual profits earned by the firm are not sustained over time at levels above or below the allowed ROE level. To some extent, the lag between rate cases under traditional COS regulation provides short-term (if uncertain) incentives to raise utility profits by cutting costs. In addition, regulators have resorted to ad-hoc incentive mechanisms, namely penalties and rewards linked to DSM programs and quality of service standards, as well as energy efficiency targets, outside of a PBR scheme.

[10] FERC Order No. 679 also established other incentives to reduce a project's financial and regulatory risks. These include the inclusion of 100 percent of Construction Work in Progress ("CWIP") in rate base, the recovery of 100 percent of pre-commercial costs as an expense or as a regulatory asset, and the recovery of 100 percent of prudently incurred abandoned plant costs.

Annex 1. Current PBR Programs for Unbundled Electricity Distribution in the US

Jurisdiction (Company)	Type of Plan	Period between Tariff Reviews	Earnings Sharing Mechanism
California			
San Diego Gas & Electric, SCE, PG&E	Revenue Cap based on multiple forward-looking Test years	3-5 years[11]	In any year of the review period when the difference between the 12-mo. average Moody's utility bond rates and the benchmark exceeds +/-100 b.p., ROE is automatically adjusted by one-half of the difference at the end of the year; SCE's cost of debt and preferred equity are reset to latest forecast values for the following year, and the current value of the index becomes the new benchmark value.
Massachusetts			
NSTAR	Price Cap (RPI –X)	5 years	Sharing of earnings outside of a ROE deadband.
Oklahoma			
Centerpoint Energy Resources	Revenue Cap (RPI –X)	5 years	Earnings beyond 100 b.p. deadband around a 10.5% ROE are allocated 75% to customers and 25% to shareholders.
Maine			
Central Maine Power	Price Cap (RPI –X)	5 years	No cap on earnings.

The existing PBR schemes for electricity distribution include a price cap or revenue cap scheme. The arrangement typically includes an indexation formula that applies to electricity distribution tariffs (or revenue requirements) each year as a function of the previous year's prices, an inflation index, and a productivity offset or efficiency factor (X). The length of such plans varies, but it is generally three or five years. Utilities' PBR plans also include specific penalty provisions associated with service reliability targets, customer satisfaction (which looks at parameters such as number of complaints, speed of answering customer calls, installation of new services by the promised date), health and safety.

In addition, the current PBR plans for distribution include earning-sharing mechanisms that establish specified thresholds on allowed earnings, or deadbands around the allowed rate-of-

[11] A full review of the utility's cost of capital cannot be shorter than three years. The latest PBR period for the three California IOUs was of five years (2008 – 2012).

return. By sharing with ratepayers any earnings outside of the specified band, the firm is protected against extreme losses between tariff reviews, while will also forego extreme profits. These forms of earning sharing mechanism were first introduced along with the rate freeze provisions at the time of the energy industry restructuring. The existing distribution PBR plans have retained this mechanism, in large part due to pressure from customer groups, generally suspicious of the ability of utilities to retain above normal profits between tariff reviews. In the case of California utilities, the prior RPI-X plan was modified in 2008 to establish a multi-year revenue cap with a provision for a multi-year automatic cost of capital mechanism. This mechanism allows for annual adjustments to the ROE if certain thresholds in utility bond returns are reached.

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Amparo Nieto is an economist based in NERA's Los Angeles office, where she specializes in the economic regulation of the energy industry. Since 1995, she has advised a large number of utilities and regulatory commissions around the world on electricity wholesale market reforms; regulatory analysis; marginal and embedded cost studies; mechanisms to support investment in renewable resources; auctions for electricity standard offer service; generation capacity market rules; and transmission cost allocation policies. She has assisted utilities and energy regulatory commissions in the US and Canada, as well as in Ireland, Spain, Australia, New Zealand, Argentina, Mexico, Brazil, Barbados, and Kenya. In Spain, she assisted in the design of wholesale market rules at the time of restructuring the electricity sector. Ms. Nieto is Director of the "Marginal Cost Working Group", which is attended by regulatory managers at electric and gas utilities from the US and Canada and addresses regulatory reforms and price strategies in the context of wholesale and retail competition. Ms. Nieto has presented numerous papers on energy regulatory matters at many energy industry forums and has been published in *The Electricity Journal* and the Centre for the Study of Regulated Industries (CRI).

Education

Fiscal Studies Institute, Madrid, Spain
Masters Degree (with Honors), Public Finance and Economic Analysis, 1996

Carlos III University, Madrid, Spain
B.A., Economics, 1994
Specialization in microeconometrics, financial analysis and competition policy.

Professional Experience

NERA Economic Consulting

2000 – present: Senior Consultant, Los Angeles, US

1995 – 1999: Consultant, Analyst, Madrid, Spain

Selected Consulting Experience

Regulatory Analysis and Planning

Barbados Federal Trade Commission, Jan 09 – Oct 09. Directed the NERA team in charge of assisting the Barbados regulatory entity in its review of the electric utility's Rate Application. Audit of the key aspects of the determination of utility revenue requirement, computation of embedded and marginal electricity cost studies, assessment of class cross-subsidy policy and restructuring of the Barbados Light & Power Company rates.

MidAmerican Energy Company, Iowa, March 09 – June 09. Directed the NERA team in charge of reviewing MidAmerican Energy Retail Group's compliance with ERCOT, MISO and PJM wholesale market rules, Resource Adequacy standards, Open Access Transmission Tariff (OATT) schedules and operating procedures.

Duquesne Power and Marubeni Power International, March 09. Contributed to the review of key regulatory and financial issues related to Marubeni's investigation of purchasing a minority share of Duquesne. Review the transmission and distribution CapEx expenditures identified in the long-term financial model provided by Macquarie, review of transmission investment opportunities resulting from Duquesne's location near the Midwest ISO.

Australian Energy Market Commission, Sidney, Australia, Feb 08 – May 08. Co-authored a report on Smart Metering regulatory requirements in the US for the Australian Commission.

Regulatory Office for Network Industries (RONI), Slovakia, Nov 07 – June 08. Directed the NERA team that assisted the Slovakian regulatory commission on the design of efficient renewable energy sources (RES) support mechanisms and a reliable system of issuing guarantees of origin for RES. Trained the commission staff on best practice RES regulation.

MidAmerican Energy Company, Iowa, Sep – Dec 2007. Directed the NERA team in charge of reviewing MidAmerican Energy Retail Group's compliance with MISO and PJM electricity wholesale market rules, Resource Adequacy standards and OATT tariffs.

Southern Minnesota Municipal Power Agency, 2007. Wrote a report on the factors affecting the decisions of building new capacity versus long-term contracting as part of a utility's Integrated Resource Planning.

New Brunswick Power, New Brunswick, Canada. 2006. Ms Nieto was one of the two experts providing joint testimony on behalf of NB Power on the role of DSM and demand response mechanisms in the resource planning process and load forecasts. The testimony assessed whether NB Power sufficiently integrates DSM and DR into its long-term load forecast.

Macedonian Regulatory Commission for Energy, Macedonia. 2006. Review and design of proposals for a “feed-in” tariff regime to recover the costs of renewable resources, in particular small hydro-power plants.

Chinese State Electricity Regulatory Commission (SERC). US 2006. Provided training to the SERC on electricity tariff policy, as part of a multi-disciplinary project funded by the World Bank to strength the capability for effective regulation of the power sector in China.

Edison Electric Institute, 2006. Co-authored a report on adoption of Smart Meters for Electricity, Time-Based Rate Structures, and Net Metering arrangements, discussing the issues that regulators and utilities need to address in the light of the 2005 Energy Policy Act.

Electricity Regulatory Board (ERB), Kenya, Africa, 2002-03. Co-authored an Electricity Tariff Policy for ERB, aimed to ensure the financial health of the sector and promote the efficient provision and expansion of electricity service. Provided recommendations for a design of efficient transmission pricing; reviewed the pricing terms of the “Interim Power Purchase Agreement” between the incumbent generator (KenGen) and the major distribution utility (KPLC); developed financial models for use in calculation of utility revenue requirement; provided on-site training to the ERB staff on regulatory analysis.

Transmission Policy and Cost Allocation

Grid Australia, Sidney 2012: Authored a report for Grid Australia (the body representing the electricity transmission network owners in Australia) analyzing procurement methods for transmission investment, and use of a competitive solicitation process by Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) in the US, as a result of FERC’s Order 1000.

Grid Australia, Oct 08 – Dec 08. Contributed to a report for Grid Australia with an analysis of the regulatory process for coordinating transmission network expansion to accommodate renewable generation in California.

BC Hydro, Canada, June 2008 – Dec 08. Supervised electricity transmission marginal cost study to support BC Hydro in its upcoming rate case.

Midwestern Utility, March-May 2007. Advised on the design of wholesale rates for back-up and supplemental energy service provided by the utility to generators connected to its network, such as wind farms and co-generators.

Alberta Electric System Operator (AESO), Calgary, Alberta, 2006. Analysed AESO’s cost study and transmission cost recovery methods. Deliver presentation with findings and discussed methods to improve cost allocation.

Australian Energy Market Commission (AEMC), Sydney, Australia, 2005. Contributed to a report advising the regulatory commission on transmission pricing and revenue requirement provisions under the Australian national electricity rules.

Tariff Design

NYISO, New York, 2012. Provided recommendations to the New York Independent System Operator for a reform of their wholesale rate mechanism for Black Start service.

Abu Dhabi Regulation and Supervision Bureau, Abu Dhabi, 2012. Directed a project to provide economic advice to the Bureau in allocating costs to different customer classes and establishing an efficient structure for electricity distribution use of system charges.

Otter Tail Power Company, Fergus Falls, MN, US. 2010. Provided support to the utility in the development of more efficient class revenue requirements for their electricity rates in Minnesota, taking marginal costs into account.

BC Hydro, British Columbia, Canada, Aug 09 – Oct 09. Directed the review of the methodology for setting BC Hydro Reactive Power Service and Voltage Control Rates.

Otter Tail Power Company, Fergus Falls, MN 2007-09. Prepared a report on the appropriateness of phasing out declining block rates; updated the marginal cost study for generation, transmission and distribution service and recommended marginal cost-based TOU tariffs for major customer classes based on the results of the cost study.

Los Angeles Department of Water and Power, California, US, 2002 – 2009. Series of projects to advise the utility on a large range of costing and pricing areas, including: electricity marginal cost studies; rate design towards more efficient time-of-day rate structures; Energy Cost Adjustment (ECA) mechanism; distributed generation rates; analysis of potential impact of CAISO market design reforms on the utility’s generation opportunity costs; and review of the utility’s embedded cost of service models for support in tariff-related litigation.

Hawaiian Electric Company, USA, 2008: Provided advice on technical, transmission and distribution tariff design, and regulatory issues related to wheeling of renewable power generated by governmental agencies.

Saudi Electricity Company, Saudi Arabia, Feb 08 – Aug 08. Assisted Saudi utility on a reasonable approach to standby and buyback rates for cogeneration facilities.

Otter Tail Power Company, 2006. Fergus Falls, MN, USA Developed a revenue-neutral, marginal-cost-based, time-of-day rate for large general service electric customers in North Dakota. Assignment included extensive analysis of alternative pricing periods.

Hawaiian Electric Company, Hawaii. US. 2006-07. Advised the utility on improvements to their Power Cost Adjustment, options to hedge fuel price risks and electricity rate smoothing mechanisms to moderate the impact of sudden fuel price changes.

Manitoba Hydro, Winnipeg, Manitoba, 2004-05. Advised Manitoba Hydro on electricity tariff reform to introduce Time-Of-Use rates and inverted- block rates in Manitoba. Analyzed the pattern of market prices for Manitoba Hydro's exports to the US in order to develop marginal energy costs by time-of-day periods; developed the welfare and cost-benefit models that took into account a range of price elasticities by class and the potential load shifting due to new TOU rate structures and the impact on net welfare. Co-authored the study report for submission to the Manitoba Public Utility Board.

Commission for Energy Regulation, Ireland, 2003-04. Advised the regulatory commission in Ireland on the review of their electricity tariff structures. Evaluated the existing locational tariffs for generators and transmission access tariffs for distributors, including charges for connection to the system. Developed marginal cost estimates for transmission, provided recommendations on efficient tariff structures and connection policy. Trained the Commission staff on tariff screening models.

Cost of Service Studies

Rochester Gas & Electric Corp. and New York Gas & Electric Corp, USA. New York, USA. 2012. Directed a project to update the electricity and gas marginal delivery cost studies of the two companies, currently subsidiaries of Iberdrola USA. Provided guidance for the reconfiguration of their electricity tariffs. A second phase of the project will begin in 2013 and will involve providing expert testimony for the utilities rate case filings.

NV Energy, Nevada, 2011 (on-going). Directed the team that advised NV Energy in a review of their marginal cost methods and provided regulatory support during implementation phase.

Con Edison, New York. 2011. Developed marginal cost estimates of transmission and distribution for use in the context of demand-side management and energy efficiency programs.

CPI USA North Carolina LLC, North Carolina, US. June – August 2010. Reviewed CPI USA's avoided cost calculations in the context of the firm's arbitration with Progress Energy Carolinas, Inc. Commented on the robustness of the method employed by both parties to determine the appropriate energy and capacity prices under long-term power purchase agreements for two CPI USA's qualifying facilities. Filed affidavit with the North Carolina Utilities Commission.

Otter Tail Power Company, MN, US. 2007-08. Prepared marginal cost studies for OTP's rate cases in ND and SD, with rate design assistance and testimony to follow in a subsequent phase.

Xcel Energy, Minnesota, US, 2005. Headed the marginal costing work involving development of generation, transmission, distribution, and retailing cost estimates for Northern States Power Company (a subsidiary of Xcel Energy) in Minnesota.

Newfoundland Power, Newfoundland, Canada, 2006. Managed the team developing a generation and transmission marginal cost of service study, which included projections for 2007-2025 for use in Demand-Side-Management efforts.

Tennessee Valley Authority (TVA), TN, US. 2006. Participated in a generation and transmission marginal cost of service study for TVA as basis for setting rates and evaluate demand response programs.

Newfoundland Labrador & Hydro, Newfoundland, Canada, 2006. Participated in a study of the marginal cost of generation and transmission for the vertically-integrated utility in Newfoundland, for its use in Time-of-Use rates.

Otter Tail Power Co., Minnesota 2004-05. Involved in a study of the distribution costs avoided as a result of Demand-Side Management; design and size of credits for costs avoided as a result of distributed generation; review of Otter Tail Power’s marginal generation and transmission cost methods based on MISO wholesale trading arrangements.

Nicor Gas, Naperville, IL, 2004-05. Modeled the marginal costs of natural gas transmission and distribution service for Nicor Gas, and advised the utility on methods for setting efficient gas delivery rates and class-revenue requirements.

Manitoba Hydro, Winnipeg, Manitoba, 2003-04. Advised Manitoba Hydro on embedded-cost methods for classification and allocation of generation and transmission costs that take into account the utility’s opportunity costs.

Wholesale Energy and Capacity Market Design

ISO-New England, May – June 2010. New England, US. Assisted the Independent System Operator in the review of certain aspects of the existing Forward Capacity Market (FCM) and in particular, the Alternative Capacity Price Rule and impact on bidding strategies in the capacity auctions.

Review of Singapore Electricity Market, July – Aug 2008. Contributed to the review of the Singapore wholesale market, in particularly in the area of generation capacity payments to generators.

California Electricity Market Review, May 2007. Prepared an analysis of the electricity wholesale market in California and the price clearing rules on behalf of a private equity firm.

Single Electricity Market, 2006. Ireland. Advised the Commission for Energy Regulation on a high-level generation capacity payment mechanism in the new Irish Single Electricity Market.

Commission for Energy Regulation (CER), Dublin, Ireland, 2006. Developed a regulatory strategy to address market power mitigation in the all-island wholesale electricity market (the SEM) in Ireland.

Mighty River Power Ltd., New Zealand, 2005. Assisted Mighty River Power Ltd. in preparing comments to the New Zealand Electricity Regulatory Commission's 2005 Consultation Report on Transmission Alternatives. Contributor to a report discussing mechanisms to provide transmission investment incentives and the potential negative efficiency implications of adopting the procurement options suggested by the Commission.

Dresdner Kleinwort Wasserstein, London, UK, 2005. Reviewed the California electricity wholesale market, including an analysis of the existing CAISO-operated energy and ancillary service markets, the CAISO congestion management process, reliability problems of the transmission system and transmission access pricing, and the expected market policy and regulatory changes.

Endesa, Rome, Italy, 2003. Assisted Endesa-Italia to develop several potential capacity payment schemes for Italy. Wrote a report on the remuneration method for electricity generators in Chile, including a description on how capacity payments are calculated for pumping and hydro plants, and a discussion of the problems and criticism of the mechanism to date.

Procurement and Auction Design

PECO Energy Company, Pennsylvania, 2012 (on-going). Coordinating the Independent Evaluator team that administers the Default Service Supply solicitations on behalf of PECO Energy Company. The auctions procure standard offer full-requirements power for Default Service residential, commercial and industrial customers.

Southern California Edison, Los Angeles, California, 2011. Provided advice to the Supply Group of the utility regarding procurement of new generation resources including renewables.

First Energy, Sep 2009 - 2011. Philadelphia, US. Manager of the NERA team in charge of administering the Default Service Supply solicitations via a descending-clock auction on behalf of Met-Ed and Penelec utilities in Pennsylvania. The auctions procure standard offer full-requirements power for Default Service residential, commercial and industrial customers.

PPL Electric Utilities Corporation, Pennsylvania. US. 2009. Advised PPL on and evaluated bids for the procurement of Demand Response and Energy Efficiency products.

PECO Energy Company, Pennsylvania. US, July 08 – Sep 09. Provided regulatory advice to design a competitive procurement process for the acquisition of electric generation and retail rates pursuant to PECO's Default Service Plan.

Spanish National Energy Commission (CNE), Madrid, Spain, Sep 07 – June 08. Administered the default service electricity supply ("CESUR") auctions. The descending-clock auctions were held on behalf of the main regulated distribution companies in Spain and Portugal. Assessed the bidders' competitive behavior during the auctions and prepared a report for the Commission.

Selected Project Reports

Before The State Of North Carolina Utilities Commission, Affidavit: Review of Alternative Application of the Peaker Method Proposed by EPCOR USA North Carolina LLC. with respect to Computation of Avoided Energy and Capacity Costs. July 23, 2010.

Before the New Brunswick Board of Commissioners of Public Utilities, Rebuttal Testimony on behalf of New Brunswick Power. The role of DSM and other Demand Response mechanisms in utility's load forecasting and resource planning. November 8, 2006

Expert Report on behalf of Los Angeles Department of Water and Power (LADWP), regarding alleged overcharging of governmental electric customers by LADWP. Los Angeles County, Los Angeles Unified School District, and Los Angeles Community College District ex rel. Barakat Consulting Incorporated and Samir F. Barakat, Plaintiffs v. Los Angeles Department of Water and Power and Does 1-50, Defendants. (Co-authored with Hethie Parmesano). August 7, 2006.

Publications

"Wholesale Energy Markets: Setting the Right Framework for Price Responsive Demand". *The Electricity Journal*. December 2012.

"Locational Electricity Capacity Markets: Alternatives to Restore the Missing Signals". *The Electricity Journal*. Volume 20, March 2007. Also published in "The Line in the Sand: The Shifting Boundary between Markets and Regulation in Network Industries." September 2007.

"Responding to EPAct 2005: Looking at Smart Meters for Electricity, Time-Based Rate Structures, and Net Metering". Prepared for, and published by, Edison Electric Institute. (With Kenneth Gordon and Wayne Olson), May 2006.

"Performance-Based Regulation of Electricity Transmission in the US: Goals and Necessary Reforms". *Energy Regulation Insights* (NERA Newsletter publication), Issue 28, March 2006.

"The Electricity Sector in Spain." Utility Regulation in the EU. Privatisation International and Centre for the Study of Regulated Industries (CRI). *Utility Regulation 2000 series*, Volume 1. June 2000.

"Effects of the Removal of the Subsidies to the National Coal Industry on Electricity Tariffs, Sector Income and Social Welfare in Spain." Masters Thesis. Institute of Fiscal Studies. Madrid, Spain, Dec. 1995. (Available only in Spanish.)

Selected Presentations

“Making Sense of Demand Response and its Role within Wholesale Energy and Capacity Markets." A paper presented at the *Center for Research in Regulated Industries* (CRRI), 25th Annual Western Conference. Monterrey, California, June 2012.

“Achieving Efficient Demand Response through Dynamic Rates”, Law Seminars International conference. Las Vegas, Nevada, Feb 9, 2009.

“Probability of Peak Analysis for TOU Rate Design”, a paper presented at the Marginal Cost Working Group in Boston, MA, Oct 8, 2008.

“Critical Peak Pricing: A Marginal Cost Approach”, a paper presented at the Marginal Cost Working Group in Phoenix, Arizona, April 2008.

“Demand Bidding Programs in ISO/RTO Environments”, presented at the Marginal Cost Working Group (MCWG), Austin, Texas. October 12, 2006

“Electricity Rate Structure Design: Sector Issues in Rate Design, Marginal and Embedded Cost Studies”; a lecture delivered at the at the University of PURC/World Bank as part of the International Training Program on Utility Regulation and Strategy, Florida, January 16, 2007.

“Locational Generation Capacity Payments in New England,” paper presented to the Marginal Cost Working Group (MCWG). Albuquerque, New Mexico, April 27, 2005.

“Transmission Pricing – Should Generators Pay for Transmission?” paper presented to the Marginal Cost Working Group (MCWG). Phoenix, Arizona, November 15–17, 2004.

“Using Marginal Costs in Electricity Embedded Ratemaking,” paper presented to the California Municipal Rates Group (CMRG). Sacramento, California. August 2004.

“Electricity Quality of Service Regulation: A Look at Europe and Australia,” paper presented to the Spring Marginal Cost Working Group (MCWG) Meeting. Orlando, Florida, April 2004.

“Marginal Costs under FERC’s Standard Market Design,” paper presented to the Marginal Cost Working Group (MCWG) Meeting. San Diego, California, April 2003.

“Real-time Pricing and Load-Curtailment Programs. Adapting to an RTO Environment,” paper presented at the Marginal Cost Working Group (MCWG) Meeting. Nevada, October 2001.

“Analysis of the International Experience with Performance Based Regulation,” paper presented at the Marginal Cost Working Group (MCWG) Seminar. Nevada, April 3-5, 2000.

29 January 2013

Design and Implementation of Incentive Regulation for Electricity Transmission Businesses

1 Introduction and overview

1.1 *Scope of this note*

PricewaterhouseCoopers Australia (PwC or "we") has been asked by Grid Australia, in the context of the Productivity Commission's (Commission) current Inquiry into electricity network regulation, to comment on the application of incentive regulation to transmission businesses, with specific regard to the two challenges the Commission has identified, namely:

- the potential for incentives for cost reduction inadvertently to provide an incentive for cost reductions to be delivered at the expense of service performance (i.e. incentives for under-investment), and
- the scope for the incentive arrangements to deliver the prospect of windfall gains or losses that are at a level that compromises the sustainability of the regime.

We have also been asked to outline how incentive regulation is applied to electricity transmission businesses in the United Kingdom (UK), again focussing specifically on matters relevant to the Commission's concerns.

The Commission has identified particular features of the transmission sector (with its discussion focussing for the most part on a comparison with the distribution sector) that it considers exacerbate its concerns about the application of incentive regulation, most notably:

- the fact that transmission outages tend to be rare but costly events makes it difficult to attach meaningful financial incentives to transmission service performance,[1] and
- the lumpy nature of transmission augmentation investment means that a change in demand growth compared to the forecast can imply a material change in cost (that is, if projects are sufficiently large, the change in financing cost caused by advancing or deferring a project by only a couple of years is material).[2]

To address its perceived shortcomings with applying incentive regulation to transmission providers, the Commission recommended in its draft report that augmentation investment decisions be vested in the not-for-profit Australian Energy Market Operator (AEMO), and has also expressed an interest in applying the contingent projects mechanism more broadly, for example, to all projects above a specified threshold. The contingent project mechanism involves providing TNSPs with an allowance for transmission projects only after a specific project is undertaken. This removes any disincentive to

1 Productivity Commission, Inquiry into Electricity Network Regulatory Frameworks, Transcript of Proceedings, at Canberra on Thursday 6 December 2012, p.297

2 Productivity Commission, Inquiry into Electricity Network Regulatory Frameworks, Transcript of Proceedings, at Canberra on Thursday 6 December 2012, p.303.

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undertake investment (as there would be no financial gain from deferring or avoiding investment) and likewise would reduce the potential for windfall gains and losses, but would reduce the scope of the incentive regime.[3]

The broader observations set out in this letter draw upon the experience of the authors with the design of the incentive arrangements in Australia, especially in the formative years of our regulatory experience, and the observations on the practice in the UK is based upon publicly available material and supplemented by conversations with colleagues in the UK firm of PwC.

1.2 *Summary of conclusions*

In summary, this note identifies the following:

- The objective of incentive regulation as a component of the framework for economic regulation is to provide a profit motive to transmission network service providers (TNSPs) to deliver outcomes that are desirable from the perspective of society. It follows that incentive regulation can only be applied to decisions that are made by commercial entities.

- The rationale for incentive regulation is that this allows the information and expertise of the regulated business to be harnessed and also simplify the process of regulation, which is expected to result in superior outcomes than a framework where decisions are made by a regulatory or other central planning type authority. A number of challenges are inevitable when designing incentive regulation and perfection is probably unattainable; however, an imperfect system of incentive regime may nonetheless offer an improvement over the alternative. A relevant parallel is the belief in mainstream economics that a large deviation from perfect competition is required before regulatory intervention to an industry is justified.

- Our terms of reference has asked that we review the relevant practice in the UK. Regulatory practice in the UK would be expected to offer important lessons for Australia. Economic regulation in the UK (which began as a critical element to the privatisation of the formerly state owned telecommunications, water, gas and electricity assets in the 1980s and 1990s) commenced with a “blank sheet of paper” and so was able to learn from the lessons from the US practice of utility regulation, most notably the perceived poor incentive properties and consequent cost and complexity of traditional US utility regulation. Indeed, the initial design of frameworks for economic regulation in Australia and the key Australian regulatory decisions have drawn extensively on the practice and experience of UK economic regulation.

- The Commission has identified two matters (referred to above) that are clearly challenges for implementing incentive regulation. However, these are issues that need to be addressed with the application of incentive regulation to any sector. Indeed, it is our view that the natural increase in transparency afforded through the lumpiness of transmission investment means that the extent that they may cause distortions might be more identifiable, and therefore more straightforward to address, for transmission than for distribution.

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3 For example, where projects are treated as contingent projects, the scope to use of financial incentives to influence the timing of investment is removed, including the incentive to use small capital projects or non-network options to defer major capital projects. Similarly, the scope to use financial incentives to encourage the selection of the lowest cost option for a project is also lost under a contingent project regime.

- A range of measures can be applied to offset any incentive to degrade service performance levels. While the capacity to apply an incentive regulation solution may be more limited for transmission there are numerous other methods that exist to enforce service levels. These include mandatory obligations, attaching rewards and penalties to certain outcomes, public reporting or legal action for extreme cases of a material failure to deliver on service performance requirements.

- Addressing the issue of material windfall gains or losses is central to the design of many aspects of the regulatory regime; noting for instance, that a key criterion of the form of price control in the distribution sector is to calibrate the growth in revenue with the growth in cost. For transmission, where revenue caps are a more appropriate form of price control, there are a range of measures that exist and have been used to reduce the potential for windfall gains or losses. A consistent element here, however, is the linking of cost drivers to revenue outcomes recognising that this decision, and the actual mechanisms used for making adjustments, can influence the extent and type of financial incentives that ultimately remain.

- The incentive regulation framework in the UK, upon which the Australian regime is based, is a regime that is focused on providing powerful incentives to reduce costs combined with a strong emphasis on defining the outputs (or outcomes) expected by regulated utilities and holding the utilities to account for the delivery of those outcomes, including through financial incentives.

  - Service performance is encouraged (and under-investment discouraged) through a combination of measures, which include licence obligations for some dimensions of service, financial incentives linked to the delivery of some outcomes and requirements for public reporting, with a large array of service measures targeted. Where financial incentives are applied, in some cases these incentives are directed to encouraging an optimal level of service (i.e., with the rewards/penalties based on consumer value), while for others the incentive is designed to remove any financial benefit (and in some cases, provide a penalty) from not meeting an outcome.

  - Ofgem addresses the potential problem of windfall gains or losses by setting, or changing, revenue allowance depending on the certainty, or realisation, of certain cost drivers. Those costs that are more certain will form part of a baseline allowance and be subject to the full range of financial incentives (these are particularly high powered in the UK regime). However, the revenue allowance can vary on the basis of volume drivers that relate to changes in the demand of customer or generation connections or the need for network capacity improvements. A mechanism similar to the contingent projects mechanism in the NEM also applies for material reinforcements of the transmission network. The extent that these measures retain the full range of financial incentives is dependent on the specific mechanisms applied to adjusting the revenue allowance.

2 Background and context

2.1 Meaning and objectives of incentive regulation

The term incentive regulation is used in this note to refer to a form of price regulation that provides a commercial (profit) incentive for regulated businesses to act in a manner or to deliver outcomes that are considered desirable from the perspective of society. Some of the outcomes that may be (and have been) the target of incentive regulation include: the minimisation of operating and capital expenditure for a given level of service; the efficient connection of new customers; the selection of the optimal level of a particular dimension of service; and the setting of a structure of prices that is efficient (meaning that the deadweight loss from pricing above marginal cost to meet a cost recovery constraint is minimised).[4]

The rationale for applying incentive regulation is that it is believed to deliver better outcomes for society than the alternative of a regulatory or other central planning type authority being involved in a range of operational decisions for which it may be poorly placed. Thus, by providing regulated businesses with a commercial incentive to act in a socially desirable manner, the full private information and expertise of the regulated entity would be expected to be harnessed to find ways to achieve the relevant objective, and simultaneously the process of regulation is simplified.

While it may seem like a "leap of faith" that incentive regulation may deliver better outcomes than a central planning model, the original pressure for incentive regulation arose from a very real dissatisfaction with the traditional form of utility regulation in North America, where the incentives on regulated businesses for desirable outcomes were weak, and as a consequence, regulatory processes were frequent and unnecessarily complex and broad in their coverage. These and other issues with the traditional form of regulation in the US were spelled out in a persuasive report by Professor Littlechild for the UK government prior to the latter privatising its utility infrastructure in the 1980s, and led to the latter embarking on a conscious decision to implement an incentive regulation regime for its newly privatised industries.

We note as a caution, however, that it is not just challenging, but most likely impossible, to design incentive schemes that fully align the commercial incentives of regulated businesses with outcomes that are desirable from the perspective of society. This has a direct parallel in the unregulated sectors, namely that there are probably no markets that correspond to the theoretical ideal of perfect competition. In continuing this parallel, it is our view that imperfect incentive regulation is likely to deliver superior outcomes to the alternatives, for substantially the same reasons that we prefer imperfect competition to regulation or government provision, namely that commercial incentives have proven to be the most successful at driving improvement and innovation. We observe, however, that where there are shortcomings in the incentives for regulated businesses, this can be (and, in practice, is) appropriately supplemented by administrative measures, which are addressed in more detail below. Importantly, the application of administrative measures to regulated businesses is also consistent with the approach in competitive markets where obligations are placed on businesses to act in certain ways or to provide transparency where profit motives might lead them to act in ways that are not desirable from the perspective of society.

2.2 *Adoption of incentive regulation in the UK and Australia*

As noted above, the UK consciously adopted an incentive regulation regime for utility regulation when it privatised its utility infrastructure in the 1980s and 1990s, with telecommunications first privatised,

4 The objectives of incentive regulation, and the general issues and constraints that arise with the design of incentive arrangements in relation to capital expenditure, were set out in some detail in a joint paper with NERA and Gilbert + Tobin that was prepared for the Energy Networks Association for submission to the AEMC: Balchin, J., C. Dermody and G. Houston, Design of Capital Expenditure Incentive Arrangements: A Joint Report for the Energy Networks Association, 8 December 2011 (available at http://www.aemc.gov.au/Media/docs/Energy%20Networks%20Association-715fa3b5-4c38-40c7-a929-8cd21f3da049-0.pdf as Attachment B).

followed by the gas sector, water sector and then electricity. The decision of the UK to embark upon a different form of regulation to the stereotypical form of regulation in the US (referred to as "rate of return" regulation) in reality reflected the fact that the UK was starting with a "blank sheet of paper", and hence able to take account of the accumulated experience of regulation in the US over the preceding century or so, including the substantial academic writings on the incentive problems with the traditional US style of utility regulation. In contrast, while a number of jurisdictions in the US have introduced components of incentive regulation to their practices, the weight of history makes reform slow and challenging.[5]

In Australia, the new economic regulatory regimes that were created for the energy sector in the 1990s were based squarely upon an application of the UK approach to regulation in Australia.[6] In addition, as all of the UK sectors had been through at least one price review by the time that the new regimes in Australia were put into effect, lessons were learned from perceived mistakes in the UK.[7] By way of example, the UK privatised its utilities with price controls in place, but without a prescribed regulatory asset value (these were set by the relevant regulator at the first review). This was seen as subjecting the businesses to unnecessary risk (and consequently reducing sales proceeds) and so most of the Australian utilities have been privatised with a prescribed starting value in place for their assets. In addition, the UK electricity regulator re-opened the price controls to correct what was subsequently seen as excessively generous prices. This was seen widely as contrary to the proper application of incentive regulation, and so in Australia the new regulatory instruments included prescribed limits on the ability for a regulator to reopen price controls prior to a periodic review.

In addition, the foundation regulatory decisions in Australia were materially guided by the practices and decisions of the UK regulators. As an example, the Victorian regulator was advised in its first gas and electricity decisions by practitioners with direct experience in the UK. In addition, the "efficiency carry over" schemes that were introduced for electricity distribution in Victoria from 2001 and gas from 2003 for capital and operating expenditure (the latter of which remains in effect, now labelled the "efficiency benefit sharing scheme") were applications of schemes that had already been applied to the UK water sector, and were only subsequently applied to the UK electricity sector. Indeed, Australia could be said to have led the UK for a period – the incentive scheme that was applied to electricity distributors in Victoria from 2001 (and that continues, albeit through a modified mechanism, as the distribution "service target performance incentive scheme") predated the development of similar schemes in the UK.

To the extent that there has been a departure between the application of incentive regulation in the UK and Australia, it has occurred subsequent to the foundation Australian decisions. In particular, the UK has continued to refine its practice of incentive regulation, innovate and find creative solutions to practical issues or problems, whereas further development in Australia has been slow and there has

5 The other constraint to reform of utility regulation in the US stems from the fact that many of the principles of regulation derive from interpretations of the takings provision in the US Constitution (private property is deemed to be taken for public service for which just and reasonable compensation is required), which therefore cannot be simply changed by State or Federal legislation.

6 The Australian telecommunications regime was also consciously an incentive based regime. However, the (original) policy intent of encouraging facilities-based competition at all levels was more apparent here than in the UK, with a consequent impact on the regime.

7 Policy positions in Australia also took account of what were perceived as mistakes in the UK. The issues faced in light of the UK privatisation of British Gas as an integrated gas producer, transporter and retailer were used to reinforce positions on the desirability of structural separation between transmission and generation in Australia. In addition, the performance of the structurally separate but highly concentrated generation sector in the UK was used in Australia to reinforce arguments on the desirability of horizontal disaggregation of the competitive generation sector.

been a tendency to retreat in the face of practical challenges rather than to address them. The clearest example of this retreating has been in relation to the incentives for capital expenditure, where the most significant practical challenge has been to distinguish a *deferral* of a project from one period to the next from an amount that is *avoided* forever (the former obviously delivering a lower societal benefit than the latter, which needs to be factored into the reward).

- In the UK, Ofgem has tackled this issue by deriving better measures of what is expected from expenditure allowances (in the form of aggregate measures of system health and utilisation), and adjusting the reward or penalty under the incentive scheme (and, subsequently, substantially increasing the power of the incentives).

- In contrast, Australian regulators have confronted the same issue by deleting the "carry-over" element of the capital expenditure incentive arrangements. This was done by the ESC in 2005 when confronted by an apparent substantial deferral of expenditure. However, more surprisingly, the AER has recently foreshadowed removing the carry-over element of the capital expenditure efficiency arrangements in Victoria in response to its concern that expenditure may be being deferred,[8] notwithstanding the innovations in the UK on this matter over the intervening period.

More generally, there have been a number of innovations in UK regulatory practice whose merits have not as yet been debated in Australia, including:

- the comprehensive defining and measurement of the outcomes expected from expenditure allowances (as referred to above)

- the development of incentives on utilities to forecast honestly as an augmentation to the incentive to spend efficiently (which is given effect by offering utilities a menu of choices, whereby the power of the incentive varies with the expenditure allowance – referred to as the Information Quality Incentive, discussed further below), and

- moving away from the accounting concepts of operating and capital expenditure (to address what Ofgem considered to be problems with addressing the incentive to reclassify expenditure from operating to capital), and instead focussing on an assessment of total expenditure, with the recovery of expenditure based on an arbitrary split between immediate recovery (the "fast pot") and recovery over time (the "slow pot").

2.3 *Issues with applying incentive regulation in practice*

The application of incentive regulation in practice can raise challenging issues, that often require solutions that are unique to the context, with this context spanning such matters as the technology, structure and commercial and market arrangements.

We note that the two issues with which the Commission has raised as concerns – the potential for incentives for cost reduction to adversely affect service levels and the potential for the regime to deliver unsustainable windfall gains or losses – are two of the key issues that need to be addressed with the application of incentive regulation to any sector. In our view, however, these matters can be overcome for application to the transmission sector. Indeed the "lumpiness" of transmission projects (bringing

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8 AER, 2012, SPI Gas Access Arrangement– Draft Decision, September, p.49.

with it a natural increase in the transparency of a transmission business's activities) and the dramatic consequences that a major transmission outage, may make addressing some elements to these issues more straightforward for transmission than for the distribution sector. That is, outcomes may be more easily identified and linked to particular causes for transmission than might be the case with distribution. This in turn might mean that remedies are also more easily applied for transmission.

We also note that these are not the only complexities to be addressed with the design of incentive regulation. The main constraint to date in Australia with the application of higher powered incentives to capital expenditure in the utility sector, as discussed above, has been the perceived difficulty of distinguishing a deferral of capital projects from a permanent reduction in costs, with the latter delivering a larger societal gain than the former (while noting that deferring projects if possible also generates societal benefits). While it is noted that the UK has developed techniques to address this matter, the problem is inherently more tractable in the transmission sector than it is in distribution because the projects are larger and deferrals are thereby more obvious.

Our observations on the specific issues the Commission has raised follow.

2.3.1 Incentive regulation and service performance

If a regulated business only had financial incentives to reduce cost and faced no other regulatory obligations, legal liabilities or reputational concerns, then it would be expected to undertake any measure it could to reduce cost, even at the expense of service performance.

A range of measures exist that can be used to offset the incentive to degrade service, and thereby encourage cost reductions only where service is not compromised.

The nirvana of incentive regulation is to attach financial incentives directly to the service levels that are delivered, with rewards or penalties calibrated to the value placed upon the service by consumers. If feasible, this can permit the regulated business to be left to select the level of service and to trade off the benefit to consumers against cost when doing so.

In our experience attaching financial incentives to service levels is feasible only in the minority of circumstances. Constraining factors, amongst others, include the capacity to observe and measure all relevant dimensions of service, and in some cases the difficulty with establishing the societal benefit of a change to service. This is not, however, fatal to incentive regulation. The inability to attach financial incentives to service merely means that the setting of service levels cannot be left to the utility alone.

Provided that service levels can be monitored and enforced, attaching financial incentive to cost and relying more on regulator determined service obligations will still ensure that the desired service level is delivered at least cost.

Some of the regulatory and other measures that exist and are used for enforcing service levels include:

- Subjecting the regulated business to mandatory obligations, either to outputs (if they are able to be observed) or to immediate outputs or outcomes, like the extent of network redundancy (i.e., planning standards)

- Being transparent upfront about the outcomes that are expected from expenditure allowances, and committing to adjust revenues in the next regulatory period to take back the benefit received from under-delivering, possibly with a financial penalty attached

- Public reporting on the service outcomes of businesses, thereby relying on reputational concerns and the potential for future heavy-handed regulation to encourage performance, and

- The potential for network businesses to be the subject of various forms of legal action where their performance is materially outside of industry best practice.

In addition, to the extent that the enforcement on service levels is not considered to be strong, then a further option exists to reduce the power of the incentive regime to a level that is considered to be safe. Noting, however, that as the power of the incentive for capital expenditure is lowered so too is the strength of the incentive for a TNSP to seek out and identify cost minimising solutions.

The last measure that exists is to take the project out of the incentive regime and fund it as and when required, which is achieved through the contingent project regime in Australia. This is a second-best approach because it removes the capacity to use incentive regulation to influence the timing of investment (including using small capital projects and non-network options to defer major augmentations), but nonetheless may be appropriate for certain projects. Importantly, the scheme that applies in Australia is symmetrical and as such does not permit 'double-dipping' between the scheme and the ex-ante revenue allowance. In addition, the scheme also includes mechanisms that provide an incentive for TNSPs to minimise costs on a project-by-project basis.

A measure that is used extensively for transmission in Australia, the UK and elsewhere is to impose a regulatory obligation to plan the network in a certain manner. In addition, as discussed in the following section, one of the innovations that Ofgem has made in this area has been to be much more specific upfront about the expected outcomes of investment programs, thereby providing it with the basis to commit to remove the benefits from not delivering against expectations. In our view, it is arguable that defining the outcomes of an investment program for a transmission business is a much more tractable task than it is for distribution, with the greater scale (and lower number) of projects making a transmission business's actions inherently more transparent.

Lastly, we note that reputation effects and the threat of legal action would be expected to have most relevance and effect in relation to decisions that are low probability but of high consequence, which are also the sorts of events for which it is most difficult to attach financial incentives or obligations. As such, we would expect transmission businesses to be particularly motivated by these matters.

2.3.2 Windfall gains and losses

The prospect that a regulated business may make a material windfall gain or loss raises questions about the sustainability of the regulatory regime and is undesirable. Windfall losses may threaten the incentive and capacity for the regulated business to deliver the service, while large windfall gains raise questions about the political sustainability of the regime (the Commission's current inquiry being Exhibit A in this regard).

As a consequence of this, the desirability of avoiding material windfall gains or losses is central to the design of many aspects of the regulatory regime, including:

- the need for, and duration between, periodic price reviews
- the form of price control in the distribution sector, with a key criterion being to calibrate the growth of revenue with the growth of cost (noting that the lumpiness of transmission – and therefore inherent material variation in the marginal cost of growth – makes a revenue cap most feasible),
- processes for regulating the larger projects that have a high dependency on exogenous factors, and
- the scope of pass through and reopener arrangements.

A range of measures exist and have been used for reducing the potential for windfall gains and losses, a range of which have been employed in the UK, which are discussed in the next section.

We note in relation to transmission that the key area where a windfall gain or loss may occur is in relation to the reduction or increase in capital expenditure required if demand was lower or higher than forecast. It is our view that devising measures to ameliorate demand risk as a source of material windfall gain or loss should be relatively tractable, at least to a standard where the regime is sustainable. The main constraint with addressing such matters is to isolate the drivers of cost (and to distinguish this from management decisions) and then to isolate the effect of that driver on cost. In this case, the scale of transmission projects and the direct link to demand forecasts would be expected to make this issue much easier to address than it would be the case for distribution.

3 Incentive regulation for TNSPs in the UK

As indicated above, the regulatory arrangements that exist in Australia are predominately based on the framework that was implemented in the UK. As such, a close consideration of the approach to transmission regulation in this jurisdiction can be insightful when considering the future approach to economic regulation in the NEM. In particular, it is relevant to consider what approach the UK regulator has taken to ensuring a satisfactory level of service performance is maintained in the face of strong expenditure incentives, and the prospects of windfall gains or losses that might arise through cost drivers that are exogenous to the business.

It is also relevant to note at the outset that the incentive regulation framework in the UK has recently been the subject of substantial review, with some further reform. Ofgem, the UK energy regulator, undertook a review of whether, after 20 years experience, the UK approach to incentive regulation was still achieving the desired objectives and whether any changes were warranted. In particular, Ofgem looked at how best to regulate energy companies to enable them to meet the challenges and opportunities of delivering the networks required for a sustainable, low carbon energy sector.[9] Importantly, the Ofgem review reaffirmed the application of incentive regulation for transmission businesses. Further, while enhancements to incentive regulation were proposed, Ofgem's overarching finding was that the incentive regulation framework "has served customers well, delivering lower prices, a better quality of service and more than £35 bn in network investment since privatisation 20 years ago".[10]

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9 http://www.ofgem.gov.uk/Networks/rpix20/Pages/RPIX20.aspx
10 Ofgem, RIIO: A new way to regulate energy networks, Final Decision, October 2012, p.02.

3.1 *Overview of the regulatory framework*

Ofgem refers to its model of incentive regulation as RIIO, which stands for "Revenue = Incentives + Innovation + Outputs". While some commentators have pointed derisively at the obvious media focus of this renaming, both the outcomes of the review and the new label reflect a very real enhancement to Ofgem's method of regulation, with the changes most relevant to this note being:

- an enhancement of the power of the incentives provided to reduce cost, combined with
- much greater emphasis on defining the outputs (or outcomes) expected by regulated utilities and holding the relevant utility to account for delivery of those outcomes, including through the application of financial incentives.

In combination with the strengthening of incentives, the RIIO model also signalled a greater desire on the part of Ofgem to consider explicit mechanisms for reducing the exposure of businesses (and consumers) to the consequences of uncertain categories of expenditure.[11]

3.1.1 Application of expenditure incentives to TNSPs

As briefly noted above, in the UK the power of the incentive that applies to TNSPs' expenditure is determined through a form of menu regulation that is referred to as the Information Quality Incentive (IQI). The key feature of the IQI is that the stronger the alignment between the TNSP's forecast of required expenditure with the regulator's view, the higher the power of the expenditure incentive. A detailed description of how the expenditure incentive is actually determined is contained in Appendix A of this note.

What is particularly revealing about the expenditure incentives that apply to TNSPs in the UK is that they are considerably higher powered and more comprehensive than the expenditure incentives faced by Australian TNSPs. In the first instance, the UK framework provides a balanced and continuous incentive to minimise capital and operating expenditure. Further, the incentive rates (i.e. the sharing ratio of gains and losses between TNSPs and customers) are also far higher than what is applied in the NEM.

It is notable that under the first application of RIIO to transmission businesses that Ofgem has sought to substantially increase the incentive rates for capital expenditure. Under the previous regime TNSPs faced a constant 25 per cent incentive rate for expenditure. Conversely, under the RIIO two of the three TNSPs obtained the maximum incentive rate of 50 per cent[12], and National Grid (or NGET,the largest of the UK TNSPs) received an incentive rate of 46.9 per cent. [13]

In the NEM, the approach taken to the EBSS means that the maximum incentive rate applied is limited to the number of years a benefit or penalty is retained. A five year retention period (with a 7.5% WACC) would derive an incentive rate of 32.62 per cent.

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[11] Some of the other changes introduced with RIIO included more certainty with how elements of the cost of capital are determined and a mechanism to better manage the effect of changes in the cost of debt; a commitment for the intensity of Ofgem's review process to depend on the quality of proposals and an extension of the 5 year regulatory period to 8 (with the option of a limited mid-period review).

[12] The two TNSPs received the maximum incentive rate automatically on the basis of receiving an IQI score of 100. This means that Ofgem accepted their business plans in total.

[13] Ofgem, RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas, Cost assessment and uncertainty Supporting Document, 17 December 2012, pp. 116-118

3.2 *Approach to the 'challenges' of incentive regulation in the UK*

The high powered expenditure incentives that are applied to TNSPs in the UK might suggest that maintaining a desirable level of service performance and avoiding excessive windfall gains or losses are far more challenging issues than they are in the NEM. However, the transmission framework in the UK also gives significant attention to the achievement of service outcomes through a mix of incentives, regulatory obligations and administrative arrangements. Additionally, the regulatory framework includes mechanisms that mean that revenue flexes on the basis of cost drivers that are external to the business; thereby reducing the scope of windfall gains or losses.

The remainder of this section discusses the UK approach to each of these issues.

3.2.1 Service performance and obligations

A range of measures are applied in the UK in order to ensure appropriate minimum service performance outcomes are achieved (and under-investment discouraged) and to encourage service performance enhancements where it is economic to do so. The measures applied include a combination of strict licence obligations, financial incentives and administrative arrangements such as reporting requirements.

Transmission businesses in the UK are obliged by licence to build and operate the network to a certain level. Expenditure allowances for load related expenditure are predominately linked to the achievement of a planning standard. The planning standard in the UK is contained in the National Electricity System Security and Quality of Supply Standard (NESSQSS) which is administered by Ofgem. The development of the standard is the responsibility of the regulator; however, it is informed by an industry working group when making its decisions. Not meeting the standard would be a breach of a licence condition and may trigger legal proceedings and/or the loss of the TNSPs licence.

Expenditure allowances for non-load related expenditure for asset replacement and overall system performance is predominately linked to key measures that approximate network health, condition and criticality outcomes. The network health and performance outcomes that TNSPs are required to achieve form what is referred to as the Network Output Measures (NOMs). There are four measures that collectively make up the NOMs, these are:

- The Network Assets Condition Measure – which relates to the current condition of network assets, their reliability and the predicted rate of deterioration in their condition that is relevant to the present and future ability of the network assets to perform their function.

- The Network Risk Measure – which relates to the overall level of risk to the reliability of the transmission system that results from the condition of the network assets and the interdependence between network assets.

- The Network Performance Measure – which relates to technical performance aspects that have a direct impact on the reliability and cost of services provided by the TNSP as part of its transmission business.

- The Network Capability Measure – which relates to the level of the capability and utilisation of the transmission system at entry and exit points and to other network capability and utilisation factors.

As discussed below, a variety of approaches are applied in order to encourage TNSPs to achieve the NOMs.

Incentives for achieving service outcomes

In finalising its approach to the most recent price review for NGET Ofgem sets out how it intends to assess performance against network output measures. This is necessary because a financial reward or penalty is associated with achieving the measures. A financial reward is provided for justified over and under delivery and a financial penalty for unjustified over and under delivery. The size of this incentive is presently capped at 2.5 per cent of the value of the additional or avoided costs. The clear implication is that if Ofgem determines that the TNSP did not achieve the necessary network output measures that not only will it have its revenue reduced by the amount of avoided expenditure, it will also incur an additional financial penalty.

Ofgem is explicit that its approach to assessing NOMs will not be mechanistic and will consider qualitative and quantitative evidence from the TNSP. This is to recognise that in achieving the NOMs that it is possible for a TNSP to make trade-offs that may be welfare improving. On this basis Ofgem indicated that it would first assess whether the NOMs were met or not. Where the NOMs are either exceeded or not met it indicated it will consider whether the outcomes are justified on the basis of what is in the best interests of consumers:[14]

> *"2.22. We expect TOs [TNSPs] to make asset management decisions which are based on the latest information, and in the best interest of consumers. TOs can trade-off between asset categories in order to deliver an equivalent or better outcome to the NOMs target. We will not limit these trade-offs. It is for TOs to justify why they need to over-deliver in one asset category and under-deliver in another, and how the overall delivery equates to an equivalent or better level of the network risk. In the longer term we expect TOs to develop a monetisation approach to justify the trade-off.*
>
> *2.23. We propose to review the performance of NOMs following the two-tier approach in our Initial Proposals. The first tier of this process is to compare the outturn NOMs against the NOMs targets, and determine if a TO delivers the NOMs targets or not. We do not think a mechanistic dead-band of plus or minus 5 per cent around the RP4 target is appropriate, because the assets in different RP groups have different impacts on the network risk and TOs have the scope to trade-off against asset categories. Therefore, we do not propose to set out a mechanistic dead-band around the NOMs targets. We will ask TOs to provide evidence to justify their achievement of the NOMs target when we compare the outturn NOMs against the NOMs targets. Where a TO is on target, we will take no further action following the first tier review.*
>
> *2.24. For a TO that delivers the NOMs below or above the target, we will initiate the second tier of assessment process. We will ask the company to provide evidence to quantify the scale of the under or over-delivery, and justify whether the under or over delivery is in the best interest of consumers. When we set out the RIIO-T2 allowances for non-load related expenditure (NLRE), we will take the NOMs targets of RIIO-T1 as an opening position from which the company will deliver the NOMs targets of RIIO-T2. Therefore, for under delivery*

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14 Ofgem, RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas, Outputs, incentives and innovation Supporting Document, 17 December 2012, p.13.

the gap between the outturn and target NOMs of RIIO-T1 will not be funded in RIIO-T2, and for over delivery this gap will be funded through the NLRE allowance for RIIO-T2."

In addition to the output measure related to reliability and network health, TNSPs in the UK also face a number of other financial incentives and administrative arrangements related to other network performance outcomes. The table below, drawn from a table in Ofgem's recent final decision on NGET's price control, identifies the outcomes, including the NOMs, that are expected in return for the expenditure allowances, and the associated incentive for their delivery. Notably, Ofgem applies a financial incentive on TNSPs to look for reliability improvements that will be valued by customers. This is in the form of a financial reward or penalty that is linked to the value of lost load.

It is also relevant to note here that Ofgem has labelled reporting requirements and meeting statutory obligations as an incentive even though there is no financial penalty or reward associated with their achievement. While throughout this letter we have referred to incentives being linked to a financial reward or penalty, we agree with Ofgem that reputational incentives can be just as powerful, if not more so, at driving efficient decisions by regulated businesses.

Table 1: NGET's outputs and incentive parameters for RIIO-T1

Category	Output	Incentive
Safety	Compliance with safety obligations set by the Health and Safety Executive (HSE).	Statutory requirements. No financial incentive.
Reliability	Primary output based on Energy Not Supplied (ENS).	Incentive rate of £16,000/MWh which is based on an estimate of the value of lost load (VoLL). A collar on financial penalties limiting the maximum penalty to 3% of allowed revenues.
	NOMs - measures of asset health, condition and criticality with agreed targets and impacts on RIIO-T2 funding.	A penalty/reward of 2.5% of the value of any over/under delivery of network replacement outputs.
Availability	Prepare and maintain a Network Access Policy (NAP).	Reputational incentive. Potential financial incentives if relevant during development and update of NAP.
Customer Satisfaction	Develop customer/stakeholder satisfaction survey	Up to +/-1% of allowed revenue.
	Effective stakeholder engagement	Up to 0.5% of allowed revenue via a discretionary reward scheme.
Connections	To meet existing legal requirements.	General enforcement policy.
Environmental	To meet existing legal requirements.	General enforcement policy.
	SF – Baseline target calculated annually with best practice 0.5% leakage rate for new assets installed.	Differences to baseline subject to a reward/penalty based on the non-traded carbon price for carbon equivalent emissions.
	Losses – Publish overall strategy for transmission losses and annual progress in implementation and impact on transmission losses.	Reputational incentive.
	Business Carbon Footprint (BCF) – Publish BCF accounts at business level annually over RIIO-T1.	Reputational incentive.
	EDR Scheme – measures to focus on aspects of the roles of the TOs and SO not explicitly captured in RIIO-T1 incentives.	Positive reward available if achieve leadership performance across different scorecard activities.
Wider works (new investment)	Baseline wider works outputs of approximately 7,250MW of additional	NGET's scheduled baseline and SWW outputs will be subject to timely delivery

	transmission capacity funded baseline funding. Best view wider works outputs (approximately another 22,150MW) are to e funded through flexible baseline (with volume driver to adjust allowances if delivery turns out to be different) and SWW arrangements for potentially a further 7,900MW of transmission capacity.	standards. For best view wider works (i.e. non SWW), NGET required to meet NDP criteria and take forward timing and phasing of WW outputs that are in the best interests of consumers.

Source: Ofgem, RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas, Final Decision – Overview document, 17 December 2012, Table 3.

3.2.2 Treatment of windfall gains or losses

As indicated in the previous section, the Ofgem approach explicitly links expenditure allowances to certain outcomes, such as meeting a planning standard or network performance in the form of NOMs. TNSPs will lose revenue, and be further penalised, for not meeting the specified outcomes of the price determination. As such, avoiding the achievement of required outcomes would not be considered a source of potential material windfall gains or losses. The prospects of windfall gains or losses, therefore, is more likely to be the consequence of outputs changing materially, which itself is driven predominately by material changes in demand.

Given it is demand changes that are the likely driver of potential windfall gains or losses in the UK regime, augmentation expenditure is the focus of measures to reduce the scope of its impact. In the UK augmentation expenditure is split into four categories, these are:

- Customer demand related expenditure
- Generator related expenditure
- Wider works, and
- Strategic wider works.

Principally the mechanisms that exist in the UK to manage windfall gains or losses work to adjust 'baseline' revenue within the period either automatically or following a decision by the regulator. Ofgem has described its overall approach as follows:[15]

> *"Three key terms used in this document are baseline, best view and uncertainty mechanism. These are described below.*
>
> - *Baseline is the amount of allowed expenditure we set at the start of the price control for each year of RIIO-T1. Baseline typically includes expenditure for outputs where there is a reasonable degree of certainty over their need and cost.*
> - *Best view is an estimate of total expenditure based on a central scenario of the generation and demand changes as well as connection activity. Best view is made up of baseline funding and additional funding adjustments through the operation of uncertainty mechanisms.*

[15] Ofgem, RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas, 17 December 2012, p. 6.

- *Uncertainty mechanism funding is either adjusted automatically where outputs differ to the baseline level, or is triggered by events defined in the transmission licences, or is provided at certain times during the price control period after further assessment by us of needs case and costs."*

The extent that the UK framework retains the broadest range of financial incentives under the different categories of augmentation expenditure depends on the specific operation of each mechanism (such as how benchmarks are adjusted). Importantly however, for each augmentation expenditure category an incentive is maintained for businesses to identify more cost effective ways of delivering their required output measures, including through innovation.[16]

The remainder of this section describes the four forms of augmentation expenditure that exist in the UK regime and how they operate to reduce the scope for material windfall gains or losses.

Customer demand related expenditure

Customer demand related expenditure relates to the shared transmission network asset costs of meeting the supply and service performance requirements of customers. The baseline expenditure allowance includes an amount for customer demand related expenditure that is reasonably certain.

The potential for windfall gains or losses that might arise through variations to the expenditure forecast provided for in baseline expenditure is accommodated through a volume driver. The customer demand volume driver accommodates variations in costs driven from major new demand connections. Ofgem described its approach to the customer demand volume driver in its Initial Proposal document for NGET stating:[17]

> *"We propose a volume driver for Local Enabling (Exit – Shared Use) LRE [Load-related expenditure] based on demand related infrastructure with parameters set at the start of the price control for the unit costs of key components. We propose NGET would report annually on commercial agreements for customer connections it has completed, the transformer works and the length (number of kms) of OHL [overhead line] used.*
>
> *We will use the volume driver to calculate automatically the allowed expenditure for the delivered output and OHL in a given price control year and compare this to NGET's baseline allowances. An adjustment will be made to their allowed expenditure if NGET has delivered more or less than the baseline level of outputs and/or used OHL in completing the connections. The totex sharing factor of 48%[18] will apply in respect to any over or underspend (as calculated under the IQI mechanism)."*

To calculate the addition or reduction in the revenue allowance required from variations in customer connections to the forecast provided in the baseline expenditure, Ofgem sets value amounts for certain

16 We note that as part of its Final Proposals Ofgem provided a Network Innovation Allowance of 0.7 per cent of allowed revenue for NGET.

17 Ofgem, RIIO-T1: Initial Proposals for National Grid Electricity Transmission and National Grid Gas, 27 July 2012, pp 44-45

18 Note that this sharing factor was adjusted down in Ofgem's Final Proposals.

parameters.[19] The parameters that are used to apply the volume driver to customer demand related costs are:

- Substation costs (£m/SGT)
- Overhead lines (£m/cct km)
- A matrix of additional costs associated to cable undergrounding
- A construction expenditure profile to spread the cost allocation over several years (% per year), and
- An adjustment for real price effects (% per annum).

Generator related expenditure

Generator connections drive a significant proportion of transmission network costs. However, unlike for customer demand related expenditure, generator connections are more uncertain and therefore harder to predict. As such, the generation connection related volume driver is the primary source of allowed expenditure for new generation connections in each year of the price control (rather than through a baseline expenditure allowance). In this instance, the volume driver for generation connections is based on the output of additional generation capacity connected in megawatts and the circuit kilometres of overhead line and underground cabling needed in connection works.[20] As with the customer demand related volume driver there are further parameters related to the profile of expenditure and real price effects.

Wider works

Wider works relates to reinforcement works to the wider transmission system to accommodate new generation and comply with security standards. These have an output measure associated with them in the form of transfer capability across system boundaries.

NGET has baseline outputs related to wider works, however, based on its Network Development Plan (NDP) Policy processes, it is able to determine whether additional wider works are in the best interests of existing and future customers. Where it identifies an advantageous wider work it is able to advance these into its forward investment program for delivery with limited regulatory oversight. For outputs determined and delivered in accordance with its NDP Ofgem will adjust baseline revenue allowances for the efficient costs of the delivered wider works outputs through a volume driver.

In order to protect customers from the prospect of stranded assets, wider works projects are able to progress only subject to the project meeting all the stipulated conditions in one of the following categories:

<u>Category 1 wider works outputs</u>

19 It is relevant to note that the approach taken by Ofgem is broadly the same as the approach proposed in the Grid Australia submission to the Commission's Draft Report.

20 It is worth noting that the AEMC has proposed a similar method for accommodating the costs associated with generator connections as part of its Optional Firm Access model.

- The total costs of the project are less than £100m (2009-10 prices), and

- The project does not require planning permissions from a local authority or a Development Consent Order from the Secretary of State.

Category 2 wider works outputs

- The total cost of the project is less than £500m (2009-10 prices)

- Is supported by user commitment from more than one customer, and

- Has a positive needs case under a range of generation and demand scenarios.

Strategic wider works

Strategic wider works relate to material reinforcements of the transmission system that cost more than £500m or other wider works outputs that do not meet the criteria under the NDP. An allowance for a strategic wider works project is intended to cover the costs of construction works and an allowance for operating expenditure associated with the completed asset. This mechanism appears to operate largely in the same way that the contingent projects mechanism applies in the NEM.

Ofgem described its intention in implementing a strategic wider works mechanism in its Initial Proposals document:[21]

> *"1.16. The SWW arrangements are designed to ensure value for money for consumers and timely funding of the construction costs and additional opex associated with large projects that are needed to meet customer requirements of wider network capability. It will achieve this by, firstly, providing NGET with flexibility to request a reopener to fund the costs of delivering SWW outputs once more information is available; and, secondly, allowing us to apply proportionate scrutiny, on a case-by-case basis, to the needs case and project assessment for delivering SWW outputs.*
>
> *1.17. NGET has identified in their business plans a number of projects that they consider are suitable for future consideration under the SWW arrangements. We will require NGET to keep us up to date on the status of these projects, as well as give us notice of any other potential projects that emerge during the RIIO-T1 period."*

Ofgem has implemented a staged approach for the assessment of strategic wider works. Ofgem explained its staged approach as follows:[22]

> *"1.19. We propose that the SWW arrangements will generally take a staged approach for the assessment, delivery and closure of these projects. Under the assessment stage we propose to determine whether the project meets the eligibility criteria for consideration under the SWW arrangements, with reference to its cost materiality and the needs case for the project. We*

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21 Ofgem, RIIO-T1: Initial Proposals for National Grid Electricity Transmission and National Grid Gas, 27 July 2012, p.172.

22 Ofgem, RIIO-T1: Initial Proposals for National Grid Electricity Transmission and National Grid Gas, 27 July 2012, p.172.

also propose to assess the specifics of the costs and outputs for the construction phase. Following this, we propose there is the delivery stage where we would implement decisions about additional funding and output delivery and the TO will regularly report on delivery progress. We propose the final stage is delivery review and closure where we will confirm whether the TO has delivered the agreed output to the standards expected."

We note that three projects were identified by Ofgem in its Initial Proposals document.[23] These were not varied for the Final Proposals report.

* * *

Jeff Balchin Principal	Scott Stacey Associate Director

23 Ofgem, RIIO-T1: Initial Proposals for National Grid Electricity Transmission and National Grid Gas, 27 July 2012, p.57.

Appendix A: Operation of Ofgem's IQI mechanism

The IQI has three outcomes:

- it sets the Expenditure Allowance based on the ratio of the NSP's forecast to the regulator's forecast. The greater the ratio, the lower the proportion of the company's request is allowed

- it rewards or penalises "honesty" in expenditure requested with an addition (or subtraction) to total allowed revenue for the period (Additional Income). The closer the NSP's forecast matches the regulator's view, the greater the reward, while divergence results in a penalty, and

- it defines what percentage of any expenditure under spend a company may keep in additional allowed revenue, or over spend for which they must pay through its base allowance (Incentive Power). Put another way, this defines the under spend *not* shared with or over spend *not* paid for by consumers. NSPs are therefore incentivised to out-perform their expenditure allowance. The under/over spend is retained by the company for a rolling five-year period to retain timing impartiality.

The subsequent matrix below simply shows the range of outcomes according to a number of example levels of Actual Expenditure by the business over the price control period. The reward or penalty outcome is the sum of additional income and the percentage of under or over spend for which they are paid or must pay.

Ratio of NSP : Regulator forecast		**95.00**	**100.00**	**105.00**	**110.00**	**115.00**	**120.00**	**125.00**	**130.00**	**135.00**	**140.00**
Expenditure allowance		**98.75**	**100.00**	**101.25**	**102.50**	**103.75**	**105.00**	**106.25**	**107.50**	**108.75**	**110.00**
Incentive power		**52.5%**	**50.0%**	**47.5%**	**45.0%**	**42.5%**	**40.0%**	**37.5%**	**35.0%**	**32.5%**	**30.0%**
Additional income		**3.09**	**2.50**	**1.84**	**1.13**	**0.34**	**-0.50**	**-1.41**	**-2.38**	**-3.41**	**-4.50**
Actual expenditure	**90**	7.69	7.50	7.19	6.75	6.19	5.50	4.69	3.75	2.69	1.50
	95	5.06	5.00	4.81	4.50	4.06	3.50	2.81	2.00	1.06	0.00
	100	2.44	2.50	2.44	2.25	1.94	1.50	0.94	0.25	-0.56	-1.50
	105	-0.19	0.00	0.06	0.00	-0.19	-0.50	-0.94	-1.50	-2.19	-3.00
	110	-2.81	-2.50	-2.31	-2.25	-2.31	-2.50	-2.81	-3.25	-3.81	-4.50
	115	-5.44	-5.00	-4.69	-4.50	-4.44	-4.50	-4.69	-5.00	-5.44	-6.00
	120	-8.06	-7.50	-7.06	-6.75	-6.56	-6.50	-6.56	-6.75	-7.06	-7.50
	125	-10.69	-10.00	-9.44	-9.00	-8.69	-8.50	-8.44	-8.50	-8.69	-9.00
	130	-13.31	-12.50	-11.81	-11.25	-10.81	-10.50	-10.31	-10.25	-10.31	-10.50
	135	-15.94	-15.00	-14.19	-13.50	-12.94	-12.50	-12.19	-12.00	-11.94	-12.00
	140	-18.56	-17.50	-16.56	-15.75	-15.06	-14.50	-14.06	-13.75	-13.56	-13.50
	145	-21.19	-20.00	-18.94	-18.00	-17.19	-16.50	-15.94	-15.50	-15.19	-15.00

Overall, the reward/(penalty) to the company is given by:

(Allowed Expenditure – Actual Expenditure) × Efficiency Incentive + Additional Income

Incentives created within the scheme

In order to maximise their returns under the IQI scheme NSPs should do three things:

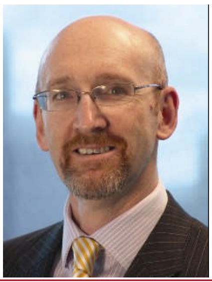
1. Regardless of the regulator's forecast, the company will maximise its total returns by submitting a forecast which it thinks, ex ante, is accurate. This is because the additional income is such that

it always maximises total returns to the company for any actual expenditure if it was accurately forecast by the company.

2. *Having fulfilled point 1*, the company should seek to forecast as low an expenditure as possible. This is because the incentive income declines as the company's forecast increases. All else equal, a low forecast expenditure has higher returns than a high forecast expenditure, *but not if the forecast is inaccurate.*

3. Regardless of its forecast, the company should be as efficient as possible throughout the price review period. Companies will not maximise their returns by manipulating their spending to meet their ex ante forecast. This is because the direction (but not the strength) of the current incentive for efficiency remains unchanged.

The outcome of the above is that a business will always be better off forecasting accurately, and once allowed expenditure is determined, seeking to spend less than the allowed expenditure.



Jeff Balchin

Principal

Jeff is an economist in the PwC Economics and Policy team. Jeff has almost 20 years of experience in relation to economic regulation issues across the electricity, gas and airports sectors in Australia and New Zealand and experience in relation to water, post and telecommunications. He has advised governments, regulators and major corporations on issues including the development of regulatory frameworks, regulatory price reviews, licensing and franchise bidding and market design. Jeff has also undertaken a number of expert witness assignments. His particular specialities have been on the application of finance principles to economic regulation, the design of tariff structures, the design of incentive compatible regulation and the drafting and economic interpretation of regulatory instruments.

In addition, Jeff has led a number of analytical assignments for firms to understand the responsiveness of consumers to changes to prices or other factors (like promotional activities) and to use this information to inform pricing strategy.

His experience is outlined below in more detail.

Relevant experience – prior to joining PwC

Prior joining PricewaterhouseCoopers, Jeff was a Director with the Allen Consulting Group and prior to becoming a consultant, Jeff held a number of policy positions in the Commonwealth Government.

- Commonwealth representative on the secretariat of the Gas Reform Task Force (1995-1996) - Played a lead role in the development of a National Code for third party access to gas transportation systems, with a particular focus on market regulation and pricing.

- Infrastructure, Resources and Environment Division, Department of the Prime Minister and Cabinet (1994-1995) - Played a key role in the creation of the Gas Reform Task Force (a body charged with implementing national gas reform that reports to the Heads of Government). During this time he also had responsibility for advising on primary industries, petroleum and mining industry issues, infrastructure issues, government business enterprise reform and privatisation issues.

- Structural Policy Division, Department of the Treasury (1992-94). Worked on environment policy issues in the lead up to the UN Conference on Environment and Development at Rio de Janeiro, as well as electricity and gas reform issues.

Relevant experience – Economic Regulation of Price and Service

Periodic Price Reviews – Major Roles for Regulators

- ACT regulated retail electricity price review (Client: Independent Competition and Regulatory Commission, ACT, 2009) – Directing a team that is developing a method to derive a benchmark cost of purchasing wholesale electricity for a retail business that is subject to a regulated price but exposed to competition.
- South Australian default gas retail price review (Client: the Essential Services Commission, SA, 2007-2008) - Directed a team that derived estimates of the benchmark operating costs for a gas retailer and the margin that should be allowed. This latter exercise included a bottom-up estimate of the financing costs incurred by a gas retail business.
- South Australian default electricity retail price review (Client: the Essential Services Commission, SA, 2007) -Directed a team that estimated the wholesale electricity purchase cost for the default electricity retail supplier in South Australia. The project

involved the development of a model for deriving an optimal portfolio of hedging contracts for a prudent and efficient retailer, and the estimate of the expected cost incurred with that portfolio. Applying the principles of modern finance theory to resolve issues of how the compensation for certain risk should be quantified was also a central part of the project.

- South Australian default gas retail price review (Client: the Essential Services Commission, SA, 2005) - As part of a team, advised the regulator on the cost of purchasing gas transmission services for a prudent and efficient SA gas retailer, where the transmission options included the use of the Moomba-Adelaide Pipeline and SEAGas Pipeline, connecting a number of gas production sources.
- Victorian Gas Distribution Price Review (Client: the Essential Services Commission, Vic, 2006-2008) - Provided advice to the Essential Service Commission in relation to its review of gas distribution access arrangements on the treatment of outsourcing arrangements, finance issues, incentive design and other economic issues.
- Envestra Gas Distribution Price Review (Client: the Essential Services Commission, SA, 2006) - Provided advice on several finance related issues (including 'return on assets' issues and the financial effect of Envestra's invoicing policy), and the treatment of major outsourcing contracts when setting regulated charges.
- Victorian Electricity Distribution Price Review (Client: the Essential Services Commission, Vic, 2003-2005) - Provided advice to the Essential Service Commission on a range is economic issues related to current review of electricity distribution charges, including issues related to finance, forecasting of expenditure and the design of incentive arrangements for productive efficiency and service delivery. Was a member of the Steering Committee advising on strategic regulatory issues.
- Victorian Water Price Review (Client: the Essential Services Commission, Vic, 2003-2005) - Provided advice to the Essential Services Commission on the issues associated with extending economic regulation to the various elements of the Victorian water sector. Was a member of the Steering Committee advising on strategic regulatory issues, and also provided advice on specific issues, most notably the determination of the initial regulatory values for the water businesses and the role of developer charges.
- ETSA Electricity Distribution Price Review (Client: the Essential Services Commission, SA, 2002-2005) - Provided advice on the 'return on assets' issues associated with the review of ETSA's regulated distribution charges, including the preparation of consultation papers. The issues covered include the valuation of assets for regulatory purposes and cost of capital issues. Also engaged as a quality assurance adviser on other consultation papers produced as part of the price review.
- Victorian Gas Distribution Price Review (Client: the Essential Services Commission, Vic, 2001-2002) - Economic adviser to the Essential Services Commission during its assessment of the price caps and other terms and conditions of access for the three Victorian gas distributors. Was responsible for all issues associated with capital financing (including analysis of the cost of capital and assessment of risk generally, and asset valuation), and supervised the financial modelling and derivation of regulated charges. Also advised on a number of other issues, including the design of incentive arrangements, the form of regulation for extensions to unreticulated townships, and the principles for determining charges for new customers connecting to the system. Represented the Commission at numerous public forums during the course of the review, and was the principal author of the finance-related and other relevant sections of the four consultation papers and the draft and final decisions.
- ETSA Electricity Distribution Price Review (Client: the South Australian Independent Industry Regulator, 2000-2001) - As part of a team, prepared a series of reports proposing a framework for the review. The particular focus was on the design of incentives to encourage cost reduction and service improvement, and how such incentives can assist the regulator to meet its statutory obligations. Currently retained to provide commentary on the consultation papers being produced by the regulator, including strategic or detailed advice as appropriate.
- Dampier to Bunbury Natural Gas Pipeline Access Arrangement Review (Client: the Independent Gas Pipelines Access Regulator, WA, 2000-2002) - Provided economic

advice to the Office of the Independent Regulator during its continuing assessment of the regulated charges and other terms and conditions of access for the gas pipeline, including a review of all parts of the draft decision, with particular focus on the sections addressing the cost of capital (and assessment of risk generally), asset valuation and financial modelling. Represented the Office on these matters at a public forum, and provided strategic advice to the Independent Regulator on the draft decision.

- Goldfield Gas Pipeline Access Arrangement Review (Client: the Independent Gas Pipelines Access Regulator, WA, 2000-2004) - Provided economic advice to the Office of the Independent Regulator during its continuing assessment of the regulated charges and other terms and conditions of access for the gas pipeline, including a review of all parts of the draft decision, with particular focus on the sections addressing the cost of capital (and assessment of risk generally), asset valuation and financial modelling. Represented the Office on these matters at a public forum, and provided strategic advice to the Independent Regulator on the draft decision.
- Victorian Electricity Distribution Price Review (Client: the Office of the Regulator-General, Vic, 1999-2000) - Economic adviser to the Office of the Regulator-General during its review of the price caps for the five Victorian electricity distributors. Had responsibility for all issues associated with capital financing, including analysis of the cost of capital (and assessment of risk generally) and asset valuation, and supervised the financial modelling and derivation of regulated charges. Also advised on a range of other issues, including the design of incentive regulation for cost reduction and service improvement, and the principles for determining charges for new customers connecting to the system. Represented the Office at numerous public forums during the course of the review, and was principal author of the finance-related sections of three consultation papers, and the finance-related sections of the draft and final decision documents.
- Victorian Ports Corporation and Channels Authority Price Review (Client: the Office of the Regulator-General, Vic, 2000) - Advised on the finance-related issues (cost of capital and the assessment of risk generally, and asset valuation), financial modelling (and the derivation of regulated charges), and on the form of control set over prices. Principal author of the sections of the draft and final decision documents addressing the finance-related and price control issues.
- AlintaGas Gas Distribution Access Arrangement Review (Client: the Independent Gas Pipelines Access Regulator, WA, 1999-2000) - Provided economic advice to the Office of the Independent Regulator during its assessment of the regulated charges and other terms and conditions of access for the gas pipeline. This advice included providing a report assessing the cost of capital associated with the regulated activities, overall review of all parts of the draft and final decisions, with particular focus on the sections addressing the cost of capital (and assessment of risk generally), asset valuation and financial modelling. Also provided strategic advice to the Independent Regulator on the draft and final decisions.
- Parmelia Gas Pipeline Access Arrangement Review (Client: the Independent Gas Pipelines Access Regulator, WA, 1999-2000) - Provided economic advice to the Office of the Independent Regulator during its assessment of the regulated charges and other terms and conditions of access for the gas pipeline, including a review of all parts of the draft and final decisions, with particular focus on the sections addressing the cost of capital (and assessment of risk generally), asset valuation and financial modelling. Also provided strategic advice to the Independent Regulator on the draft and final decisions.
- Victorian Gas Distribution Price Review (Client: the Office of the Regulator-General, Vic, 1998) - Economic adviser to the Office of the Regulator-General during its assessment of the price caps and other terms and conditions of access for the three Victorian gas distributors. Major issues addressed included the valuation of assets for regulatory purposes, cost of capital financing and financial modelling. Principal author of the draft and final decision documents.

Periodic and Other Price Reviews – Other Activities

- Regulatory cost of debt (Clients: Powerlink, ElectraNet and Victorian gas distributors

2011-2012) – provided a series of reports addressing how the benchmark cost of debt should be established pursuant to the National Electricity Rules and on the appropriate benchmark allowance for debt and equity raising costs.

- Strategic advice, Victorian electricity distribution review (Client: Jemena Electricity Networks, 2009-2011) – provided ongoing advice on regulatory economic issues during the course of the price review, including on regulatory finance matters, issues associated with the AER's desire to end the former service performance incentive scheme, issues associated with the regulatory treatment of related party contracts, allocation of costs between regulated and unregulated activities and forecasting of expenditure.
- Regulatory cost of debt (Client: Powercor Australia Limited, 2009-2010) – provided a series of reports addressing how the benchmark cost of debt should be established pursuant to the National Electricity Rules.
- Cessation of service incentive scheme (Client: Powercor Australia Limited, 2010) – assisted Powercor to quantify the financial effect that would have flowed if the former service performance incentive scheme had continued. Also prepared an expert report pointing to a material inconsistency in how the AER intended to close out the old scheme and the parameters for the new service performance incentive scheme, which was accepted by the AER.
- Strategic advice, NSW gas distribution review (Client: Jemena Gas Networks, 2009-2011) – provided ongoing advice on regulatory economic issues during the course of the price review, including on regulatory finance matters, issues associated with the regulatory treatment of related party contracts, allocation of costs between regulated and unregulated activities, forecasting of expenditure and issues associated with the updating of JGN's regulatory asset base.
- Input methodologies for NZ regulated businesses (Clients: Powerco NZ and Christchurch International Airport, 2009-ongoing) – advising in relation to the Commerce Commission's development of input methodologies and related matters, covering issues associated with regulatory asset valuation, the regulatory cost of capital, the use of productivity trends in regulation and the design of incentive-compatible regulation.
- Equity Betas for Regulated Electricity Network Activities (Client: Grid Australia, APIA, ENA, 2008) - Prepared a report presenting empirical evidence on the equity betas for regulated Australian electricity transmission and distribution businesses for the AER's five yearly review of WACC parameters for these industries. The report demonstrated the implications of a number of different estimation techniques and the reliability of the resulting estimates. Also prepared a joint paper with the law firm, Gilbert+Tobin, providing an economic and legal interpretation of the relevant (unique) statutory guidance for the review.
- Economic Principles for the Setting of Airside Charges (Client: Christchurch International Airport Limited, 2008-2009) - Provided advice on a range of economic issues relating to its resetting of charges for airside services, including the valuation of assets and treatment of revaluations, certain inputs to the cost of capital (beta and the debt margin) and the efficiency of prices over time and the implications for the depreciation of assets and measured accounting profit.
- Treatment of Inflation and Depreciation when Setting Landing Charges (Client: Virgin Blue, 2007-2008) - Provided advice on Adelaide Airport's proposed approach for setting landing charges for Adelaide Airport, where a key issue was how it proposed to deal with inflation and the implications for the path of prices over time. The advice also addressed the different formulae that are available for deriving an annual revenue requirement and the requirements for the different formulae to be applied consistently.
- Application of the Grid Investment Test to the Auckland 400kV Upgrade (Client: Electricity Commission of New Zealand, 2006) - As part of a team, undertook a review of the Commission's process for reviewing Transpower's proposed Auckland 400kV upgrade project and undertook a peer review of the Commission's application of the Grid Investment Test.
- Appropriate Treatment of Taxation when Measuring Regulatory Profit (Client:

Powerco New Zealand, 2005-2006) - Prepared two statements for Powerco New Zealand related to how the Commerce Commission should treat taxation when measuring realised and projected regulatory profit for its gas distribution business (measured regulatory profit, in turn, was a key input into the Commission's advice to the Minister as to whether there would be net benefits from regulating Powerco New Zealand's gas distribution business). A key finding was that care must be taken to ensure that the inputs used when calculating taxation expenses are consistent with the other 'assumptions' that a regulator adopts if it applies incentive regulation (most notably, a need for consistency between assumed tax depreciation and the regulatory asset value).

- Application of Directlink for Regulated Status (Client: Directlink, 2003-2004) - Prepared advice on the economic issues associated with the Directlink Joint Venture's request to be converted from an unregulated (entrepreneurial) interconnector to a regulated interconnector. As with the Murraylink application, the key issues included the implications for economic efficiency flowing from its application and the appropriate application of a cost benefit test for transmission investment (and the implications of that test for the setting of the regulatory value for its asset).
- Principles for the 'Stranding' of Assets by Regulators (Client: the Independent Pricing and Regulatory Tribunal, NSW, 2005) - Prepared a report discussing the relevant economic principles for a regulator in deciding whether to 'strand' assets for regulatory purposes (that is, to deny any further return on assets that are partially or unutilised). An important conclusion of the advice is that the benefits of stranding need to be assessed with reference to how future decisions of the regulated entities are affected by the policy (i.e. future investment and pricing decisions), and that the uncertainty created from 'stranding' creates real costs.
- Principles for Determining Regulatory Depreciation Allowances (Client: the Independent Pricing and Regulatory Tribunal, NSW, 2003) - Prepared a report discussing the relevant economic and other principles for determining depreciation for the purpose of price regulation, and its application to electricity distribution. An important issue addressed was the distinction between accounting and regulatory (economic) objectives for depreciation.
- Methodology for Updating the Regulatory Value of Electricity Transmission Assets (Client: the Australian Competition and Consumer Commission, 2003) - Prepared a report assessing the relative merits of two options for updating the regulatory value of electricity transmission assets at a price review - which are to reset the value at the estimated 'depreciated optimised replacement cost' value, or to take the previous regulatory value and deduct depreciation and add the capital expenditure undertaken during the intervening period (the 'rolling-forward' method). This paper was commissioned as part of the ACCC's review of its Draft Statement of Regulatory Principles for electricity transmission regulation.
- Application of Murraylink for Regulated Status (Client: Murraylink Transmission Company, 2003) - Prepared advice on the economic issues associated with Murraylink Transmission Company's request to be converted from an unregulated (entrepreneurial) interconnector to a regulated interconnector. The key issues included the implications for economic efficiency flowing from its application and the appropriate application of a cost benefit test for transmission investment (and the implications of that test for the setting of the regulatory value for its asset).
- Proxy Beta for Regulated Gas Transmission Activities (Client: the Australian Competition and Consumer Commission, 2002) - Prepared a report presenting the available empirical evidence on the 'beta' (which is a measure of risk) of regulated gas transmission activities. This evidence included beta estimates for listed firms in Australia, as well as those from the United States, Canada and the United Kingdom. The report also included a discussion of empirical issues associated with estimating betas, and issues to be considered when using such estimates as an input into setting regulated charges.
- Treatment of Working Capital when setting Regulated Charges (Client: the Australian Competition and Consumer Commission, 2002) - Prepared a report assessing whether it would be appropriate to include an explicit (additional)

allowance in the benchmark revenue requirement in respect of working capital when setting regulated charges.

- Pricing Principles for the South West Pipeline (Client: Esso Australia, 2001) - As part of a team, prepared a report (which was submitted to the Australian Competition and Consumer Commission) describing the pricing principles that should apply to the South West Pipeline (this pipeline was a new asset, linking the existing system to a new storage facility and additional gas producers).
- Relevance of 'September 11' for the Risk Free Rate (Client: the Australian Competition and Consumer Commission, 2001) - Prepared a report assessing the relevance (if any) of the events of September 11 for the proxy 'risk free rate' that is included in the Capital Asset Pricing Model (this is a model, drawn from finance theory, for estimating the required return for a particular asset).
- Victorian Government Review of Water Prices (Client: the Department of Natural Resources and the Environment, Vic, 2000-2001) - Prepared a report discussing the principles regulators use to determine the capital related cost (including reasonable profit) associated with providing utility services, and how those principles would apply to the water industry in particular. The report also provided an estimate of the cost of capital (and assessment of risk in general) associated with providing water services. The findings of the report were presented to a forum of representatives of the Victorian water industry.
- Likely Regulatory Outcome for the Price for Using a Port (Client: MIM, 2000) - Provided advice on the outcome that could be expected were the dispute over the price for the use of a major port to be resolved by an economic regulator. The main issue of contention was the valuation of the port assets (for regulatory purposes) given that the installed infrastructure was excess to requirements, and the mine had a short remaining life.
- Relevance of 'Asymmetric Events' in the Setting of Regulated Charges (Client: TransGrid, 1999) - In conjunction with William M Mercer, prepared a report (which was submitted to the Australian Competition and Consumer Commission) discussing the relevance of downside (asymmetric) events when setting regulated charges, and quantifying the expected cost of those events.

Relevant experience – Development of Regulatory Frameworks

- Review of the Australian energy economic regulation (Client: Energy Networks Association, 2010-ongoing) – assisting the owners of energy infrastructure to engage in the current wide-ranging review of the regime for economic regulation of energy infrastructure. Advice has focussed in particular on the setting of the regulatory WACC and on the regime of financial incentives for capital expenditure efficiency, and included strategic and analytical advice, preparation of expert reports and assistance with ENA submissions.
- Review of the Australian electricity transmission framework (Client: Grid Australia, 2010-ongoing) – assisting the owners of electricity transmission assets to participate in the wide-ranging review of the framework for electricity transmission in the national electricity market, covering such matters as planning arrangements, the form of regulation for non-core services and generator capacity rights and charging. Has included analytical advice on policy choices, facilitation of industry positions and articulation of positions in submissions.
- Implications of greenhouse policy for the electricity and gas regulatory frameworks (Client: the Australian Energy Market Commission, 2008-2009) – Provided advice to the AEMC in its review of whether changes to the electricity and gas regulatory frameworks is warranted in light of the proposed introduction of a carbon permit trading scheme and an expanded renewables obligation. Issues addressed include the framework for electricity connections, the efficiency of the management of congestion and locational signals for generators and the appropriate specification of a cost benefit test for transmission upgrades in light of the two policy initiatives.
- Economic incentives under the energy network regulatory regimes for demand side participation (Client: Australian Energy market Commission, 2006) – Provided advice to the AEMC on the incentives provided by the network regulatory regime for demand side participation, including the effect of the form of price control (price cap

vs. revenue cap), the cost-efficiency arrangements, the treatment of losses and the regime for setting reliability standards.

- Application of a 'total factor productivity' form of regulation (Client: the Victorian Department of Primary Industries, 2008) - Assisted the Department to develop a proposed amendment to the regulatory regime for electricity regulation to permit (but not mandate) a total factor productivity approach to setting price caps – that is, to reset prices to cost at the start of the new regulatory period and to use total factor productivity as an input to set the rate of change in prices over the period.
- Expert Panel on Energy Access Pricing (Client: Ministerial Council on Energy, 2005 2006) - Assisted the Expert Panel in its review of the appropriate scope for commonality of access pricing regulation across the electricity and gas, transmission and distribution sectors. The report recommended best practice approaches to the appropriate forms of regulation, the principles to guide the development of detailed regulatory rules and regulatory assessments, the procedures for the conduct of regulatory reviews and information gathering powers.
- Productivity Commission Review of Airport Pricing (Client: Virgin Blue, 2006) - Prepared two reports for Virgin Blue for submission to the Commission's review, addressing the economic interpretation of the review principles, asset valuation, required rates of return for airports and the efficiency effects of airport charges and presented the findings to a public forum.
- AEMC Review of the Rules for Setting Transmission Prices (Client: Transmission Network Owners, 2005-2006) - Advised a coalition comprising all of the major electricity transmission network owners during the new Australian Energy Market Commission's review of the rules under which transmission prices are determined. Prepared advice on a number of issues and assisted the owners to draft their submissions to the AEMC's various papers.
- Advice on Energy Policy Reform Issues (Client: Victorian Department of Infrastructure/Primary Industries, 2003-ongoing) - Ongoing advice to the Department regarding on issues relating to national energy market reform. Key areas covered include: reform of cross ownership rules for the energy sector; the reform of the cost benefit test for electricity transmission investments; and the reform of the gas access arrangements (in particular, the scope for introducing more light handed forms of regulation); and the transition of the Victorian electricity transmission arrangements and gas market into the national regulatory regime.
- Productivity Commission Review of the National Gas Code (Client: BHPBilliton, 2003-2004) - Produced two submissions to the review, with the important issues including the appropriate form of regulation for the monopoly gas transmission assets (including the role of incentive regulation), the requirement for ring fencing arrangements, and the presentation of evidence on the impact of regulation on the industry since the introduction of the Code. The evidence presented included a detailed empirical study of the evidence provided by the market values of regulated entities for the question of whether regulators are setting prices that are too low.
- Framework for the Regulation of Service Quality (Client: Western Power, 2002) - Prepared two reports advising on the framework for the regulation of product and service quality for electricity distribution, with a particular focus on the use of economic incentives to optimise quality and the implications for the coordination of service regulation coordinated with distribution tariff regulation.
- Development of the National Third Party Access Code for Natural Gas Pipeline Systems Code (Client: commenced while a Commonwealth Public Servant, after 1996 the Commonwealth Government, 1994-1997) - Was involved in the development of the Gas Code (which is the legal framework for the economic regulation of gas transmission and distribution systems) from the time of the agreement between governments to implement access regulation, through to the signing of the intergovernmental agreements and the passage of the relevant legislation by the State and Commonwealth parliaments. Major issues of contention included the overall form of regulation to apply to the infrastructure (including the principles and processes for establishing whether an asset should be regulated), pricing principles (including the valuation of assets for regulatory purposes and the use of incentive regulation), ring fencing arrangements between monopoly and potentially

contestable activities, and the disclosure of information. Was the principal author of numerous issues papers for the various government and industry working groups, public discussion papers, and sections of the Gas Code.

Relevant experience – Pricing work for non-regulated businesses

- Application of the netback calculation for MRRT purposes (Client: Confidential, 2011-12) – advised on how 'arms length prices that would be observed in a competitive market' for the use of downstream infrastructure should be computed, focussing in particular on what economic principles predicts for the valuation of assets, the rates of return and the potential for providers to earn higher returns arising from incentive compatible contracts.
- Cost justification of airport charges (Client: Dunedin Airport, 2010-11) – assisted Dunedin Airport to quantify the cost of providing its airport landing and terminal charges and justify to its major customers a substantial increase in its charges.
- Australian airport landing charges (Client: Virgin Australia, 2009-12) – have assisted Virgin during its negotiations of airport landing and terminal charges for a number of Australian airports, including review of the airports' proposed pricing models, asset valuation methods and proposed rates of return.
- Measuring the effectiveness of promotions (Client: a major Australian department store 2011/12) – as part of a team, drawing on 'point of sale' information to estimate the effect of price and promotions on sales (using transaction information) as part of a major review of the store's promotional activities.
- Estimating the price sensitivity of consumers for retail goods (Client: a major Australian supermarket (2010/11) – led a team to develop of a dynamic model to estimate the sensitivity of sales of an item to its price, the price of substitutes and other factors using transactions data. Allowed the client to predict how changing prices across a group of close substitutes would affect margin and to understand the effect of promotional activities.

Relevant experience – Regulatory due diligence and related work

- Sale of the Sydney Desalination Plant (Client: a consortium of investors, 2011-12) – Prepared a regulatory due diligence report for potential acquirer of the asset, including a review of the financial modelling of future pricing decisions.
- Sale of the Abbot Point Coal Terminal port (Client: a consortium of investors / debt providers, 2010-11) – Prepared a regulatory due diligence report for potential acquirer of the asset, including a review of the financial modelling of future pricing decisions.
- Private Port Development (Client: Major Australian Bank, 2008) - Prepared a report on the relative merits of different governance and financing arrangements for a proposed major port development that would serve multiple port users.
- Sale of Allgas gas distribution network (Client: confidential, 2006) – Prepared a regulatory due diligence report for potential acquirer of the asset.
- Review of Capital Structure (Client: major Victorian water entity, 2003) - Prepared a report (for the Board) advising on the optimal capital structure for a particular Victorian water entity. The report advised on the practical implications of the theory on optimal capital structure, presented benchmarking results for comparable entities, and presented the results of detailed modelling of the risk implications of different capital structures. Important issues for the exercise were the implications of continued government ownership and the impending economic regulation by the Victorian Essential Services Commission for the choice of – and transition to – the optimal capital structure.

Relevant experience – Expert Witness Roles

- Victorian gas market pricing dispute – dispute resolution panel (Client: VENCorp, 2008) – Prepared a report and was cross examined in relation to the operation of the Victorian gas market in the presence of supply outages.
- Consultation on Major Airport Capital Expenditure – Judicial Review (Client: Christchurch International Airport, 2008) - Prepared an affidavit for a judicial

review on whether the airport consulted appropriately on its proposed terminal development. Addressed the rationale, from the point of view of economics, of separating the decision of 'what to build' from the question of 'how to price' in relation to new infrastructure.

- New Zealand Commerce Commission Draft Decision on Gas Distribution Charges (Client: Powerco, 2007-2008) - Prepared an expert statement about the valuation of assets for regulatory purposes, with a focus on the treatment of revaluation gains, and a memorandum about the treatment of taxation for regulatory purposes and appeared before the Commerce Commission.
- Sydney Airport Domestic Landing Change Arbitration (Client: Virgin Blue, 2007) - Prepared two expert reports on the economic issues associated with the structure of landing charges (note: the evidence was filed, but the parties reached agreement before the case was heard).
- New Zealand Commerce Commission Gas Price Control Decision – Judicial Review (Client: Powerco, 2006) - Provided four affidavits on the regulatory economic issues associated with the calculation of the allowance for taxation for a regulatory purpose, addressing in particular the need for consistency in assumptions across different regulatory calculations.
- Victorian Electricity Distribution Price Review – Appeal to the ESC Appeal Panel: Service Incentive Risk (Client: the Essential Services Commission, Vic, 2005-2006) - Prepared expert evidence on the workings of the ESC's service incentive scheme and the question of whether the scheme was likely to deliver a windfall gain or loss to the distributors (note: the evidence was filed, but the appellant withdrew this ground of appeal prior to the case being heard).
- Victorian Electricity Distribution Price Review – Appeal to the ESC Appeal Panel: Price Rebalancing (Client: the Essential Services Commission, Vic, 2005-2006) - Prepared expert evidence on the workings of the ESC's tariff basket form of price control, with a particular focus on the ability of the electricity distributors to rebalance prices and the financial effect of the introduction of 'time of use' prices in this context (note: the evidence was filed, but the appellant withdrew this ground of appeal prior to the case being heard).
- New Zealand Commerce Commission Review of Information Provision and Asset Valuation (Client: Powerco New Zealand, 2005) - Appeared before the Commerce Commission for Powerco New Zealand on several matters related to the appropriate measurement of profit for regulatory purposes related to its electricity distribution business, most notably the treatment of taxation in the context of an incentive regulation regime.
- Duke Gas Pipeline (Qld) Access Arrangement Review – Appeal to the Australian Competition Tribunal (Client: the Australia Competition and Consumer Commission, 2002) - Prepared expert evidence on the question of whether concerns of economic efficiency are relevant to the non price terms and conditions of access (note: the evidence was not filed as the appellant withdrew its evidence prior to the case being heard).
- Victorian Electricity Distribution Price Review – Appeal to the ORG Appeal Panel: Rural Risk (Client: the Office of the Regulator General, Vic, 2000) - Provided expert evidence (written and oral) to the ORG Appeal Panel on the question of whether the distribution of electricity in the predominantly rural areas carried greater risk than the distribution of electricity in the predominantly urban areas.
- Victorian Electricity Distribution Price Review – Appeal to the ORG Appeal Panel: Inflation Risk (Client: the Office of the Regulator General, Vic, 2000) - Provided expert evidence (written and oral) to the ORG Appeal Panel on the implications of inflation risk for the cost of capital associated with the distribution activities.
- Major Coal Producers and Ports Corporation of Queensland Access Negotiation (Client: Pacific Coal, 1999) - Provided advice to the coal producers on the outcome that could be expected were the dispute over the price for the use of a major port to be resolved by an economic regulator. The main issues of contention were the valuation of the assets for regulatory purposes, whether the original users of the port should be given credit for the share of the infrastructure they financed, and the cost

of capital (and assessment of risk generally). Presented the findings to a negotiation session between the parties.

Qualifications and memberships

- B.Ec. (Hons.) at the University of Adelaide (First Class Honours)
- CEDA National Prize for Economic Development

Scott Stacey

Associate Director

Scott specialises in the analysis of economic and regulatory issues in the utilities and infrastructure sectors, in particular, the application of incentive regulation to network businesses. Scott has extensive experience on major policy reviews of energy market issues having had lead roles in the development of the rules for economic regulation of electricity networks in the National Electricity Market as well as on matters such as network pricing, demand-side participation, retail competition, and regulatory frameworks for transmission and distribution networks.

Scott also has had previous roles with the Australian Energy Market Commission (AEMC), Network Economics Consulting Group/CRA, the Essential Services Commission in Victoria and in the Commonwealth Government's Energy Market Reform Branch.

Relevant experience – PwC

- Economic Regulation Rule changes)Energy Networks Association and Grid Australia) – provided assistance and advice for responding to the AER's proposed Rule changes for the Economic Regulation of Network Businesses, in particular on the issues of the incentives for efficient capital expenditure, the framework for expenditure forecasting and the approach to the cost of capital.
- Approach to revaluing an asset base for hospitals - provided advice on the economics and issues associated with different approaches to revaluing an asset base and the implications this might have for depreciation over the longer term.
- Efficient operation of price signals in the NEM (AEMC) – provided a report to the AEMC to assist it with its Power of Choice Review which is looking into the role of demand-side participation in the NEM. The advice considered what is an economically efficient price in the NEM given the drivers of costs, the efficiency of different price structures, and also analysed the extent the structure of existing tariffs reflected economic principles
- Efficient pricing of network services (WA Public Utilities Office) – this work involved the preparation of a discussion paper to consider the economic principles for efficient network pricing and the extent the existing Access Code in WA reflected those principles. A key issue for this paper was also the impact of increased penetration of photovoltaic cells on pricing.
- Network incentives for DSP (Energy Networks Association) – this report considered the incentives on electricity network service providers to procure demand-side participation in the NEM. This included the incentives to set efficient prices for DSP as well as incentives to procure additional demand response from customers.
- Electricity Access Code Review (WA Public Utilities Office) – the provision of ongoing assistance and advice, including the preparation of targeted discussion papers, to assist the PUO's review of the 2004 Electricity Access Code WA.

- Transmission Frameworks Review (Grid Australia) - ongoing assistance, including for submissions, in response to the AEMC's Transmission Frameworks Review. Specific issues considered include generator access, network planning and network connections.
- Garnaut Climate Change Review (Grid Australia) – provided assistance with the drafting of a submission to the Garnaut Climate Change Review.
- AMI cost recovery (Government Department) – provided advice on the economic principles for charging customers for the costs of advanced metering infrastructure.
- Retail price impacts of climate change policies (NSW Energy Retailer) – provided advice relating to the implication of changes to climate change policies on retail costs and the ability for these costs to be recovered under a regulated tariff framework.
- Energy Efficient Street-lighting (Department for Transport, Energy and Infrastructure) – provided a report on the regulatory barriers to the roll out of energy efficient street lights in the NEM.

Relevant Experience – AEMC

- Review of Demand-side Management in the NEM – project manager for this review which involved investigating the integration of the demand-side into all elements of the electricity supply chain. A key element of this work was the innovative analysis into the relationship between the price cap form of price control and incentives for network businesses to use demand-response.
- Review of Energy Market Frameworks in light of Climate Change Policies managed the networks component of this review which required a review of whether changes to the electricity and gas regulatory frameworks is warranted in light of the proposed introduction of a carbon permit trading scheme and expanded renewable obligation. Issues addressed included the framework for electricity connections, the efficiency of the management of congestion and the appropriate specification of tests for upgrades to the transmission network.
- Review of Transmission Revenue and Pricing Rules – this significant project involved developing new Rules for the economic regulation of transmission networks in the national market. It was the first review of these arrangements since the commencement of the NEM. The project culminated in the create of a new chapter, 6A, in the National Electricity Rules.
- Ministerial Council on Energy –Assisted the Expert Panel in its review of the appropriate scope for commonality of access pricing regulation across the electricity and gas, transmission and distribution sectors. The report recommended best practice approaches to the appropriate forms of regulation, the principles to guide the development of detailed regulatory rules and regulatory assessments, the procedures for the conduct of regulatory reviews and information gathering powers.
- Project management of various Rule changes relating to topics such as economic regulation, ancillary services and demand-side management.

Previous Experience – NECG/CRA

- Assessment of the impacts of proposed changes to the National

Electricity Code and law from a generators perspective.

- Assessment of the regulatory and competitive impacts of a vertical merger in the electricity industry.
- Advice on the economic consequences of maintaining significant producer legislation and cross ownership restrictions in the Victorian energy market.
- Advice on the impacts of changes to the price control regime within the telecommunications sector.
- Analysis for an international client on the structure and design of the Australian telecommunications industry.
- Advice to the metropolitan water businesses on the development and contents of a Bulk Water Code including its underlying principles. In addition, this work considered some of the issues related to the handling of recycled water in Melbourne.
- Advice relating to a proposed joint venture within the Western Australian grains industry.
- Analysis of the relationship between the development of Voice over Internet Protocol and the existing telecommunications access regime. This work identified the potential gaps in the regime in the context of this new technology.
- Analysis of the impact from a change in termination charges for mobile phone calls across customer segments.

Previous Experience – Essential Services Commission of Victoria

- Preparation of a draft report for the design of the Retailer of Last Resort Scheme for the electricity and gas sectors.
- Issues paper to develop the Victorian guideline for embedded generation.
- Final Report for the review of metrology procedures in Victoria.
- Ad hoc analysis on issues such as cross-ownership, national electricity market issues, distribution tariffs and pricing principles.

Qualifications and memberships

- Bachelor of Economics with Honours, James Cook University.