15 March 2013

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Mr John Pierce
Chairman
Australian Energy Market Commission
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Submitted online

Dear Mr Pierce

AEMC's review of the implications of differences between actual and forecast demand for the network regulatory frameworks.

AEMO welcomes the opportunity to provide a submission on the AEMC's review of the implications of differences between actual and forecast demand for the network regulatory frameworks.

AEMO is of the view that the current National Electricity Rules (NER) will not address the issues arising from differences between actual and forecast demand. AEMO supports incentive regulation which aligns the interests of network businesses with the long term interest of consumers. However, the present incentives on network businesses:

- Have delivered revenue reset applications incorporating high demand forecasts; and
- Have supported over-investment in high capital cost projects.

This is particularly the case where network businesses are projecting significant investment to meet demand growth.

The new provisions under S6A.2.2A provide for the regulator to review capital spending in a previous control period and reduce the regulated asset base only if the TNSP overspent its capital spending allowance for that period (the overspending requirement). This would appear to exacerbate the incentive on regulated businesses to over-forecast.

Through other processes, there is separate consideration of the use of AEMO's forecasts in the regulatory regime. Use of AEMO's national energy forecast would remove any potential biases. This is potentially more important than before given the changing nature of demand in the NEM. Over the past five years there has been a change in the consumption patterns of consumers, structural changes to the economy and advances in technology which makes task of demand and energy forecasting is becoming more challenging.

Given the inherent forecasting difficulties, AEMO considers that more efficient outcomes would be delivered by moving investment decision making to the latest time reasonably practicable and focus the ex-ante revenue cap scheme on driving efficient management of the current assets. The option value of delay enables a more considered view of both the need and the option selected.

To implement these changes AEMO proposes the following amendments:

- Moving all material augmentation capital expenditures (above the RIT-T threshold) out of the periodic revenue reset process and into an expanded contingent projects regime.
- Extending the regulatory control periods to at least 5 years and up to 8 years for all the replacement capital expenditure to provide a longer term incentive to drive more efficient management and utilisation of existing assets.

This approach will ensure that the risk of customers unnecessarily incurring costs due to demand being lower than forecast will be minimised and network service providers (NSPs) will not face incentives to underinvest if demand and other augmentation drivers are higher than expected. It continues to provide certainty to network businesses who are will have certainty prior to their investment decision and will not be subject to any ex-post adjustments. This certainty will be further improved with the longer revenue and price determination process and enable NSPs to optimise network replacement and refurbishment decisions.

Accordingly, we consider that our proposal will enhance the ability of the network regulatory frameworks to deliver both the NEO and the revenue and pricing principles in the NEL.

While we focus predominantly on transmission network regulation, these approaches may be relevant to distribution network regulation, at least in respect to sub-transmission investment.

Further, these changes can be developed and implemented quickly and can be made in time for the next round of revenue and price determinations scheduled for 2014.

In the longer term, the industry must develop an understanding of the effects of declining demand growth, and reduced energy consumption, on network replacement decisions. However, this will take some time to develop and may need a broader to analyse and consider the implications of this.

The attached submission sets out our thoughts on this matter.

If you have any questions please do not hesitate to contact Louis Tirpcou on (03) 9609 8415.

Yours sincerely

David Swift
Executive General Manager Corporate Development

Attachment:

Draft Submission on the Treatment of Augmentation Expenditure

REGULATORY TREATMENT OF AUGMENTATION EXPENDITURE

PREPARED BY: Corporate Development

DOCUMENT REF: Enter Document Ref

VERSION: 1

DATE: Enter Date

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Contents

1 Background and Overview

In January, the Standing Council on Energy and Resources (SCER) requested advice from the AEMC on the implications of differences between actual and forecast demand for the network regulatory frameworks.

In particular, the AEMC was asked to advise SCER on the merits of:

- the AER considering differences between actual and forecast demand under the current regulatory framework; and
- changes to the current arrangements that could improve the flexibility of the existing frameworks without compromising the AEMC's ability to deliver the National Electricity Objective (NEO) or the revenue and pricing principles in the National Electricity Law (NEL).

In developing its advice, the AEMC is obliged to consult broadly with stakeholders, including AEMO.

AEMO is of the view that the current National Electricity Rules (NER) will not address the issues arising from differences between actual and forecast demand. AEMO supports incentive regulation which aligns the interests of network businesses with the long term interest of consumers. However, the present incentives on network businesses:

- have delivered revenue reset applications incorporating high demand forecasts; and
- have supported over-investment in high capital cost projects.

This is particularly the case where network businesses are projecting significant investment to meet demand growth.

The new provisions under S6A.2.2A provide for the regulator to review capital spending in a previous control period and reduce the regulated asset base only if the TNSP overspent its capital spending allowance for that period (the overspending requirement). This would appear to exacerbate the incentive on regulated businesses to over-forecast.

Through other processes, there is separate consideration of the use of AEMO's forecasts in the regulatory regime. Use of AEMO's national energy forecast would remove any potential biases. This is potentially more important than before given the changing nature of demand in the NEM. Over the past five years there has been a change in the consumption patterns of consumers, structural changes to the economy and advances in technology which makes task of demand and energy forecasting is becoming more challenging.

Given the inherent forecasting difficulties, AEMO considers that more efficient outcomes would be delivered by moving investment decision making to the latest time reasonably practicable and focus the ex-ante revenue cap scheme on driving efficient management of the current assets. The option value of delay enables a more considered view of both the need and the option selected.

To implement these changes AEMO proposes the following amendments:

- Moving all material augmentation capital expenditures (above the RIT-T threshold) out of the periodic revenue reset process and into an expanded contingent projects regime.
- Extending the regulatory control periods to at least 5 years and up to 8 years for all the replacement capital expenditure to provide a longer term incentive to drive more efficient management and utilisation of existing assets.

This approach will ensure that the risk of customers unnecessarily incurring costs due to demand being lower than forecast will be minimised and network service providers (NSPs) will not face incentives to underinvest if demand and other augmentation drivers are higher than expected. It continues to provide certainty to network businesses who are will have certainty prior to their investment decision and will not be subject to any ex-post adjustments. This certainty will be further improved with the longer revenue and price determination process and enable NSPs to optimise network replacement and refurbishment decisions.

Accordingly, we consider that our proposal will enhance the ability of the network regulatory frameworks to deliver both the NEO and the revenue and pricing principles in the NEL.

While we focus predominantly on transmission network regulation, these approaches may be relevant to distribution network regulation, at least in respect to sub-transmission investment.

Further, these changes can be developed and implemented quickly and can be made in time for the next round of revenue and price determinations scheduled for 2014.

The benefits of this approach are evident in the Victorian context which has been set out below.

In the longer term, the industry must develop an understanding of the effects of declining demand growth, and reduced energy consumption, on network replacement decisions. However, this will take some time to develop and may need a broader to analyse and consider the implications of this.

This submission is structured as follows:

- Section 2 discusses current approaches to network planning and augmentation in the NEM; and
- Section 3 sets out AEMO's proposed solutions to the issues arising under the current regulatory frameworks.

2 Current approaches to network planning and augmentation in the NEM

2.1 AEMO Victorian approach

In its role as Victorian transmission system planner, AEMO applies an economic approach to network planning. Under this approach, the benefit of an option – including the value of unserved energy avoided due to the option – is compared to the costs of the option to determine whether the option is expected to yield net market benefits in accordance with the criteria in the Regulatory Investment Test for Transmission (RIT-T). The cost of an option is determined through a competitive tender process undertaken subsequent to the RIT-T. This model ensures that transmission investment is only undertaken if and when it is expected to deliver the most net beneficial solution, to the ultimate long-term benefit of electricity consumers.

While the need to utilise demand forecasts cannot be avoided in performing an economic analysis of augmentation options, AEMO's planning approach seeks to make use of the most up-to-date forecasts available at the time the RIT-T analysis of an option is undertaken. This helps minimise uncertainty around whether the option is worthwhile or not. Further, unless and until an option satisfies the RIT-T, customers are not required to start paying for the option.

For example, if AEMO finds that an option will maximise net market benefits if commissioned in year **t**, AEMO will undertake the RIT-T for that option as late as possible to allow the option to be commissioned by year **t**. Given the time lags involved in developing transmission options in particular, this analysis may be in year **t-3**. Subsequent to the analysis, AEMO will tender for options and the project will be committed, say, in year **t-2**. When the RIT-T analysis is undertaken, AEMO will use the most recent available forecasts at that time – which in this case will be forecasts generated in year **t-4**. For example, the joint AEMO-ElectraNet analysis of the proposed Heywood upgrade in the form of the Project Assessment Conclusions Report (PACR) was published in January 2013. The PACR drew on demand forecasts from AEMO's 2012 National Electricity Forecasting Report (2012 NEFR) for the key scenario 4.[1] If approved, the preferred upgrade option is likely to be tendered for by early 2014, from which time customers will start to contribute towards the costs of the option. The preferred option is expected to be commissioned by July 2016.[2]

This means that under AEMO's planning approach, investment decisions are made, resources are sunk and customer commence being charged on the basis of demand forecasts that are generally no more than two years old. Although not ideal, this is effectively the minimum period of 'out-of-dateness' consistent with current regulatory planning requirements (ie the RIT-T and its associated consultation and AER assessment processes).

2.2 Other approaches

Most other TNSPs in the NEM forecast the bulk of their capital expenditures for the forthcoming regulatory control period based on the joint consideration of:

- forecasts of peak electricity demand and
- the need to avoid violating deterministic reliability standards.

In addition, if a TNSP considers that the need for an augmentation is uncertain, the TNSP is able to nominate the project as a contingent project, which may be undertaken if a defined trigger event occurs.[3]

Such approaches have two implications for the role of demand forecasts in economic regulation:

- First, with a 5-year regulatory control period, TNSPs develop their augmentation capital expenditure forecasts on the basis of demand forecasts made up to six years prior to the

[1] AEMO and ElectraNet, *South Australia – Victoria (Heywood) Interconnector Upgrade, RIT-T: Project Assessment Conclusions Report*, January 2013 (Heywood Upgrade PACR), Table 5.1, p.82.
[2] Heywood Upgrade PACR, p.29.
[3] Under Rule 6A.8 of the NER.

date augmentation expenditure is expected to be incurred and even longer in advance of the required commissioning date of an augmentation; and

- Second, the ability for TNSPs to nominate contingent projects effectively shields the TNSP from the risk that demand is greater than forecast, thereby creating an asymmetric set of payoffs to the TNSP if demand diverges from forecasts.

These points are expanded on below.

2.2.1 Use of out of date demand forecasts

As noted above, in the standard regulatory process for TNSP revenue determination, augmentation expenditure forecasts (upon which network charges are based) are made using demand forecasts that may have been developed up to six years prior to the date of the forecast expenditure.

A recent example of the role of demand forecasts in setting augmentation capital expenditure allowances is the ElectraNet revenue proposal for the period 1 July 2013 to 30 June 2018.

ElectraNet's original proposal dated 31 May 2012 noted that: "Growth in customer peak demand is the principal driver of transmission system augmentation and connection point reinforcement."[4] ElectraNet developed its capital expenditure forecasts on the basis of:

- AEMO's 2011 South Australian Supply and Demand Outlook – this was used for planning main grid augmentations (10% PoE forecasts used); and
- Peak connection point demand forecasts provided by ETSA utilities (now SA Power Networks) from May 2012 and direct-connected customers – this was used for connection point planning and local regional planning.[5]

ElectraNet's revised revenue proposal of 16 January 2013 incorporated a modified capital expenditure forecast based on:

- AEMO's 2012 state-wide forecasts, which ElectraNet said are consistent with AEMO's 2012 NTNDP; and
- Updated peak connection point demand forecasts provided by SA Power Networks (from December 2012) and direct-connected customers.[6]

ElectraNet's use of recent demand forecasts is best-practice. ElectraNet worked closely with AEMO to understand our forecasting methodology and approach to developing our 2012 forecasts. ElectraNet also undertook a significant amount of its own work through 2012 to ensure the forecasts used for developing its revenue proposal were as up-to-date and accurate as possible.[7] Nevertheless, the fact remains that demand forecasts developed in 2012 will be used to determine the level of network charges customers will pay in 2017/18 and perhaps beyond depending on the form of capital expenditure incentives regime that applies.

The problem with using out-of-date demand forecasts is that customers are required to pay part of the costs of investments that may not be required or undertaken during that regulatory control period (or longer). For example, consider the example of the Dumaresq-Lismore line project in northern NSW. This project was initially proposed by TransGrid in its original revenue proposal for the 2009-2014 regulatory control period.[8] The expenditure on the project was expected to be incurred over 2009/10 to 2011/12.[9] The AER accepted the likely need for the project but ultimately

[4] ElectraNet, *ElectraNet Transmission Network Revenue Proposal 1 July 2013 – 30 June 2018*, 31 May 2012 (ElectraNet original proposal), p.64.
[5] ElectraNet original proposal, p.64.
[6] ElectraNet, *ElectraNet Transmission Network Revised Revenue Proposal 1 July 2013 – 30 June 2018*, 31 May 2012 (ElectraNet revised proposal), pp.69-70.
[7] ElectraNet revised proposal, p.28.
[8] TransGrid, *TransGrid Revenue Proposal, 1 July 2009 – 30 June 2014*, 31 May 2008 (TransGrid original proposal), pp.63-64.
[9] TransGrid original proposal, p.74.

reduced the allowed expenditure on the project to $151 million (in 2008$).[10] Accordingly, TransGrid's 2009-14 revenue cap includes a return on and of this expenditure, which TransGrid's customers are currently paying for through TUoS charges.

The AER Final Decision noted that TransGrid had determined that the downward revisions to the NSW DNSPs' demand forecasts would have 'no impact' on its capital program within the 2009-2014 regulatory control period.[11] However, TransGrid's website now states:

> *As a result of updated demand forecasts, which were published in the Annual Planning Report 2012 (APR) on 29 June, TransGrid believes the proposed transmission line would not be required until winter 2016. It is possible this date may be further deferred to the 2020s if electricity imports can continue to be relied upon from Queensland via the coast.*
>
> *While it is difficult to determine the exact drivers of the recent volatility in consumers' peak electricity consumption; increasing power prices, global economic uncertainty and mild weather could be some of the factors contributing to lower than expected peak demand.*[12]

Effectively, this means that TransGrid's customers have unnecessarily funded the return on and of over $150 million (in 2008$) in capital expenditure though much of the current regulatory control period due to the fact that TransGrid's allowed revenue requirement was derived from capital expenditure determined on the basis of demand forecasts that have turned out to be far too high.

Grid Australia has questioned the materiality of the implications for customers of using over-stated forecasts, suggesting that ElectraNet's adoption of a 10% lower demand forecast in the current revenue determination would only reduce network charges by $30 million over 5 years (about 2% of the maximum allowed revenue (MAR)).[13] However, Grid Australia's comment relates only to a one-off forecast demand reduction of 10% that results in a 20% lower 5-year capital expenditure forecast. It may be the case that forecast demand is reduced by more or again during the regulatory control period, implying an even larger unnecessary tariff increase for consumers than they ought to face.

Moreover, the real question is what benefit flows to customers from forecasting augmentation expenditure up to six years in advance. The benefit from setting capital expenditure allowances several years in advance purportedly flows from the incentive regulation model. The AER's presentation to the AEMC workshop concluded with the observation that:

> *Any interventions through the regulatory period to adjust for forecasting error would undermine the current incentive regime (effectively moving to a cost of service model) and would not be in the long term interest of consumers.*[14]

However, given that:

- all TNSPs are obliged to apply the RIT-T to significant projects; and
- all TNSPs tender out asset procurement,

the incremental efficiency gains from the specific form of incentive regulation generally applied across the NEM <u>with respect to augmentation capital expenditure</u> are far from obvious. The case for maintaining the current 5-year reset form of incentive regulation is much stronger in respect of the maintenance and refurbishment of the existing regulated asset base.

2.2.2 Role of contingent projects

Under the current regulatory arrangements, TNSPs may seek to make provision for 'contingent projects' in their revenue determinations. A proposed contingent project must be not otherwise provided for in a revenue proposal and must be attributable to a specified 'trigger event' that is

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[10] AER, *Final Decision, TransGrid transmission determination 2009-10 to 2013-14*, 28 April 2009 (AER Final Decision), pp.18-19.
[11] AER Final Decision, p.15.
[12] See link: http://www.transgrid.com.au/projects/projects/dumaresq_lismore/Pages/default.aspx (accessed on 14 March 2013).
[13] Korte, R., *AEMC Workshop on Actual and Forecast Demand*, 28 February 2013, p.8.
[14] AER speaking points – AEMC demand workshop 28 February 2013, p.6.

objectively verifiable.[15] To be a contingent project, a project must satisfy all the standard requirements, such as being reasonably required to achieve the capital expenditure objectives and the expenditure must reasonably reflect the capital expenditure criteria. Further, the expenditure must exceed the higher of:

- $30 million; and
- 5% of the TNSP's first-year MAR.

In the case of ElectraNet's forthcoming regulatory reset, the first-year MAR in the revised proposal is $291.7 million.[16] Five percent of this is less than $15 million, so the $30 million threshold would apply.

The contingent project regime is designed to cater for projects that will probably (but not necessarily) be required during a regulatory control period, where the relevant trigger event is localised and where the project's costs are uncertain. We note that the final ground (costs are uncertain) was added after the publication of the Draft Rule in response to a submission by ETNOF (now Grid Australia).[17] The implications of this inclusion are discussed below.

If the AER determines that a project qualifies as a contingent project, the TNSP is able, during a regulatory control period, to apply to the AER to amend a revenue determination to account for the triggering and initiation of the contingent project.[18] The TNSP's application must include information such as forecast expenditures on the contingent project, expected commencement and completion dates and the incremental revenue requirement for each remaining year of the regulatory control period. The AER then has 40 business days following receipt of all required information to make a decision on whether to approve the application (subject to similar criteria as for a revenue proposal) and if so, how much and in what manner to amend the revenue determination. Subsequent to the amendment, the TNSP faces similar incentives to minimise the actual costs of the project as it faces for a non-contingent project. Further, as with standard augmentation capital expenditure included in a revenue determination, proponents of contingent projects are required to apply the RIT-T.

Considered in isolation, the contingent project regime offers the benefit of avoiding the drawbacks of using out-of-date demand forecasts as well as out-of-date cost estimates in the standard regulatory process. It is only if and when a contingent project trigger is satisfied (eg a demand threshold is reached) that the TNSP is required to specify the timing of the project and to formulate estimates of capital and operating expenditure associated with the project for the AER to approve.

The contingent projects regime works by transferring the intra-period risk of whether contingent projects are required to consumers:

- If a contingent project is required within a regulatory control period, consumers pay more within that period
- If it is not required, consumers do not pay more.

In addition, consumers bear the risk of changes in the costs of a contingent project between the date of the TNSP's revenue determination and the date of the TNSP's contingent project application.

When considered as an addition to the transmission regulatory framework, it becomes clear that the availability of the contingent projects regime alongside the standard reset-based regulatory regime helps to minimise TNSPs' risks at the expense of consumers. It is unsurprising that in the AEMC's 2006 review of transmission, ETNOF sought to extend the scope of the contingent projects provisions to projects where the project was fairly likely to proceed but the costs were uncertain: TNSPs have no incentive[19] to not include uncertain projects in their standard revenue

[15] NER, Rule 6A.8.1(b).
[16] ElectraNet revised proposal, p.7.
[17] AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No.18*, 16 November 2006, p.59.
[18] NER, Rule 6A.8.2.
[19] Assuming the regulated rate of return is relatively attractive.

proposals; however, TNSPs do have strong incentives to exclude even highly likely projects where the costs are uncertain or anticipated to rise if those projects can be flagged as contingent projects.

In effect, the contingent project regime provides TNSPs with a ‘safety valve’ for augmentation expenditures that may be required under particular states of the world. Although the regime is not designed to cater for general ‘high demand’ outcomes – as this is a system-wide phenomenon rather than a localised trigger event – we are unsure of any proposed contingent projects being rejected on this basis.

A key implication of the contingent projects regime acting as a safety valve for TNSPs is that it undermines the symmetry of incentives under the regulatory framework. When given a choice between the standard regulatory regime and the contingent projects regime, TNSPs will have strong incentives to:

- Include in its standard revenue proposal projects that may not be necessary and projects for which the TNSP is confident that the costs will remain reasonably stable or fall over time; and
- Classify as a contingent project projects that may be required but for which the costs are highly uncertain or expected to rise materially.

These incentives expose consumers to the risk of:

- Paying for projects (through the standard approved capital expenditure allowance) that may not be necessary within the regulatory control period (eg the Dumaresq-Lismore project in NSW discussed above); and
- Paying higher prices for contingent projects than would be the case if those same projects were included in the revenue proposal.

In combination, this means that rather than facing broadly symmetric risks around variations in demand and costs around forecasts, TNSPs will tend to face limited downside revenue risks and scope for positive upside surprises. The result is that consumers are worse off than if all projects were dealt with under either the standard regulatory regime or under a case-by-case contingent projects regime.

Under these circumstances, it makes sense to move away from the current form of incentive regulation that applies in relation to augmentation capital expenditure.

3 Proposed solution

3.1 Key elements

AEMO is of the view that minor modifications to the current network regulatory frameworks are unlikely to address the issues arising from differences between actual and forecast demand.

The problems with the current arrangements arise from a combination of the factors discussed in the previous section – that is the:

- Use of demand forecasts developed far in advance of the need for expenditure; and
- Ability of TNSPs to nominate certain projects of their choosing as contingent projects with few constraints.

More generally, the problems arise from the current half-way house regulatory framework in which TNSPs are meant to face incentives to minimise costs over a regulatory control period while at the same time being assured (in accordance with the NEL) that they will be given every chance to recover efficient costs. The present regulatory framework reconciles these objectives by rewarding TNSPs for not undertaking projects that may not be needed in any case while providing strong *ex ante* assurances that actual costs associated with any contingent projects can be fully recovered, thereby limiting TNSPs' downside risks.

AEMO proposes to address the asymmetric nature of the transmission regulatory framework by shifting all material augmentation capital expenditures (above the RIT-T threshold) out of the periodic revenue reset process and into a modified contingent projects regime. In this way, the scope for customers to incur costs unnecessarily will be minimised because consumers will only pay for the costs of such contingent projects demonstrated as being necessary and cost-efficient under the RIT-T based on the most up-to-date available information. TNSPs will then proceed – as they do now – to engage in competitive procurement in respect of these projects and have incentives to make savings relative to the agreed *ex ante* allowances for the relevant contingent projects. Meanwhile, standard reset-based incentive regulation would continue to apply to the existing sunk network, to provide incentives for maximising productive efficiency in respect of existing assets and services.

AEMO notes that in the context of TransGrid's proposed Dumaresq to Lismore line discussed above, TransGrid's website says:

> *TransGrid has also undertaken to apply the Regulatory Investment Test for Transmission (RIT-T) to the proposed development. To ensure that the most up to date information is used in that process, it would be undertaken as close as possible (considering the time necessary to complete the RIT-T process) to when lead times dictate that a commitment to the Project is required.*[20]

In other words, TransGrid will apply the RIT-T to the Dumaresq-Lismore project as late as possible to make use of the most up-to-date information possible. Again, this is consistent with best practice. However, it implies that if AEMO's proposed approach had been in place prior to the current regulatory control period (such that the Dumaresq-Lismore project was treated as a contingent project and its costs only recovered from customers subsequent to a successful RIT-T analysis), NSW customers would not have had to fund the return on and of the cost of the project over the 2009-2014 regulatory control period.

By way of comparison, AEMO notes that Victorian customers will not need to pay for the Melbourne Eastern Suburbs upgrade prematurely. This project was initially expected to be required prior to the summer of 2015/16. However, revised demand forecasts mean that the project will now not be required until the summer of 2018/19.[21] It so happens that the next Victorian transmission regulatory control period extends from 2014/15 to 2019/20, which means that recent changes to demand forecasts will be able to feed into that process. However, if the regulatory control period

[20] See link: http://www.transgrid.com.au/projects/projects/dumaresq_lismore/Pages/default.aspx (accessed on 14 March 2013).1

[21] See AEMO, *Eastern Metropolitan Melbourne Thermal Capacity Upgrade – RIT-T: Project Assessment Draft Report*, 8 March 2013, pp.2 and 43-44.

were instead, say, 2011/12 to 2016/17, these downward revisions to demand would not have arrived in time to save Victorian customers paying for the return on and of this project's costs. Under these circumstances, AEMO's approach of not requiring customers to pay for projects unless and until they are required on the basis of an up-to-date RIT-T would save customers considerable expense.

The use of such a 'conditional price caps' has support in the theoretical literature. Forsyth says:

> *While unconditional price caps* [eg price caps set derived using a standard regulatory reset approach] *can be used to encourage investment, they can lead to high profits. If conditional price caps* [eg price caps derived from a contingent projects approach] *are set but without regard to actual costs, investment can be encouraged and the firm can be given an incentive to keep the costs of investment down.*[22]

This is effectively what AEMO is suggesting. AEMO's proposed model would work as follows:

- The standard incentive-based CPI-X regulatory reset process will focus on setting allowances for capital and operating expenditures in respect of:
    - existing network assets and services, including replacement and refurbishment capital expenditures; and
    - any augmentation expenditures in respect of projects that fall below the applicable RIT-T threshold;
- All projects responsible for augmentation capital expenditures in excess of the RIT-T threshold will be assessed through a modified contingent projects regime to ensure symmetric regulatory treatment of all significant augmentation capital expenditure;
- Augmentation capital expenditure assessed as contingent projects will:
    - need to satisfy the RIT-T prior to being submitted to the AER for approval under Rule 6A.8.2; and
    - be exempt from the risk of being disallowed under the new Rule S6A.2.2A;
- Augmentation capital expenditure assessed under the contingent projects regime will be recoverable from consumers over the remainder of the current regulatory control period based on the *ex ante* determined costs of the investment established through the AER's approval of the TNSP's contingent project application under Rule 6A.8.2 (as occurs now).

While some stakeholders may suggest that these proposed changes to the regulatory framework would reduce the power of incentives applicable to TNSPs, AEMO submits that:

- Many of the incentives provided under the current arrangements simply serve to transfer wealth from consumers to TNSPs and transfer risks from TNSPs to consumers; and
- The scope for efficiencies under the owner-planner TNSP model dominant in the NEM is largely captured by competitive procurement, which would not be affected by AEMO's proposed changes.

AEMO considers that greater efficiencies would be best achieved by moving towards the Victorian transmission model, which separates planning from ownership and operation of the transmission network. In the absence of such a reform, AEMO considers that few efficiencies are obtained directly from the inclusion of augmentation capital expenditure in the regulatory reset process.

3.2 Application to distribution networks

Although the focus of AEMO's proposed changes to the regulatory frameworks is the treatment of transmission augmentation expenditure, similar principles apply to investment in sub-transmission assets by DNSPs. Such expenditure tends to be demand-driven, like much transmission augmentation expenditure. Accordingly, it makes sense for consumers to only pay for sub-

[22] Forsyth, P., *Infrastructure Regulation and Investments*, Keynote Address, 7th Conference on Applied Infrastructure Research (INFRADAY) TU Berlin, October 10-11, 2008, p.12..

transmission projects that need to be built and from the time they are required to be built, rather than to pay for these projects irrespective of whether they are required to commence development during a particular regulatory period or not.

Therefore, we propose modifying the distribution regulatory framework to ensure that projects responsible for sub-transmission augmentation capital expenditure above a reasonable threshold are assessed in a similar manner to if they were a contingent project under the transmission regulatory framework. This will help ensure consumers' risks and costs of paying for unnecessary investment are minimised over the long term.

3.3 Price shocks

AEMO's proposed reform of the network regulatory frameworks could cause intra-period network price impacts relative to the situation under the existing frameworks. This is because of AEMO's proposed expansion of the contingent projects regime for both transmission and distribution augmentation expenditure.

As noted above, the contingent projects regime works by transferring the intra-period risk of whether contingent projects are required to consumers. Taken in isolation, this suggests that consumers will face symmetrically increased upside and downside price risks during a regulatory control period if more projects are treated as contingent projects rather than managed through the standard reset-based arrangements.

However, when accounting for the shift of <u>all</u> augmentation capital expenditure to the contingent projects regime, the price impacts for consumers are likely to be less symmetric. As discussed above, under the current regulatory framework, TNSPs can pick and choose between the standard reset-based regime and the contingent projects regime in a way that is advantageous to them. This is likely to mean TNSPs face few downside revenue risks and scope for positive upside surprises under the current framework. Overcoming the scope for TNSPs to game the framework in this way could mean that as compared to the current arrangements, consumers face:

- Many more downside surprises on network charges; and
- Only a few more upside price shocks.

Although the result could be greater intra-period network price volatility compared to the present, we submit that:

- The greater volatility will largely reflect more instances of prices being lower than they would be under the present framework; and
- Any greater intra-period volatility should be offset by less inter-period volatility, as network charges will reflect network costs with less of a time lag than under the present framework.