1 December 2006

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Dr. J Tamblyn
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Dear Dr. Tamblyn

National Electricity Rule Proposal: Pricing for Prescribed Transmission Services

EnergyAustralia welcomes the opportunity to comment on the Australian Energy Market Commission's (the AEMC's) Draft Rule change for the pricing of Prescribed Transmission Services.

As we noted in our response to the Rule proposal, we are uniquely placed to comment on the AEMC's proposals from a number of perspectives.

EnergyAustralia welcomed many of the changes to the Rule proposal. However, in many instances, we believe the changes did not go far enough to fully address our concerns. The Commission maintained its position on some issues pending further comment from participants, which we provide. We also provide a more detailed example to demonstrate some of our concerns with the Rule. We would be happy to expand on this example should the Commission wish to undertake further analysis.

Finally, we have some concerns with the consequential drafting of several clauses and seek clarification of their intent. This is of utmost importance to us. Not only are the Rules substantially different in form and content from the current ones, the role of the regulator in pricing arrangements will be significantly different to what we experienced at our last Transmission determination. Clarity of roles and responsibilities will be vital to ensure a smooth operation at our next reset.

Please feel free to contact me on (02) 9269 4171 if any clarification of this matter is required.

Yours sincerely,

Harry Colebourn
Manager – Network Regulation & Pricing

Transmission Pricing: Response to AEMC Draft Determination

November 2006

Proposed Transmission Pricing Rule

Executive Summary

EnergyAustralia welcomes the opportunity to respond to the AEMC's draft determination on Transmission Pricing. Our submission focuses on 8 major areas of the draft Rule:

1. The Commission has not justified a change in approach from the current Rule proposal that adjusts revenue directly to the AARR, rather than through the Customer TUoS General Charge;
2. We support the Commission's decision to remove operating and maintenance costs as a basis for the calculation of attributable cost share. Nevertheless, we demonstrate why Optimised Replacement Cost should remain as the only basis for calculating attributable cost share;
3. The introduction of the clause "on a causation basis" only creates uncertainty to generally accepted practice. The Commission's concerns about the "confusing mix of … approaches to implement the cost allocation exercise" are addressed in the Rule without the addition of "on a causation basis". Costs that are directly attributable to a service category are precisely that. Where costs can be attributed to more than one service category, 6A.24.2(d) should apply;
4. We remain concerned about the role of guidelines in assessing pricing methodologies and the extent to which the AER could, through guidelines, dictate the nature and effect of a TNSP's pricing methodology;
5. We are concerned with the inference that the AER can consult on and make a determination on the appropriateness of a pricing methodology (or an important element of one) and is therefore able to reject existing approaches such as that given to CRNP by draft clause 6A.24.3(c);
6. There is benefit in allowing flexibility in the date prices are published. A date 3 months before the end of a regulatory year, or another date agreed between DNSP and TNSP would be appropriate.
7. The Rules are currently insufficient in clarifying the obligations of "appointing TNSPs" and "co-ordinating TNSPs" when preparing their own methodologies.
8. We are disappointed with the Commission's view that a comprehensive change to the regime for embedded generators is not within the scope of the transmission pricing rules. It is the TUoS pricing allocation which provides the sole justification for TUoS rebates and these matters cannot be separated so simply.

1 Response to Draft Rule

1.1 Aggregate Annual Revenue Requirement (6A.22.2)

The Commission has maintained its approach from the Rule proposal that sees all adjustments to the amount of revenue that may be recovered from Prescribed Transmission Service charges is made at the outset, directly to the AARR, rather than through the Customer TUoS General Charge.

We believe the AEMC's proposal is based on theoretical construct, unsupported by logical analysis. In particular statements such as the following display a different understanding of the interactions of market operation and pricing to ours:

> *"It does not make sense for consumers to receive all the benefits of IRSR proceeds[1]:.."*

IRSR proceeds arise from customers paying more than the generators receive ***in an adjacent region*** – why should a component be returned to generators ***in the same region*** when they have received the higher pool price?;

> *Because CRNP only vaguely approximates the true LRMC of network usage, a reduction in the locational component of a 50% CRNP/Postage stamp split of TUoS cost recovery is just as likely to move the pricing regime closer to true LRMC as further away*2.

Congestion based CRNP alters the 50% share of TUoS cost recovery to improve its alignment with LRMC. It is not logical to distort such a price signal in the way the AEMC proposes.

The Commission acknowledged, and EnergyAustralia agreed that this approach would involve a degree of rebalancing of charges[3]. EnergyAustralia believes this to be material, noting that TransGrid's settlement surpluses factored into its FY07 prices are $107M, representing about 22% of the total revenue of $484M[4]. While no information was provided on the $/MWh or % impact on final bill to justify a return to the current approach, there seems to have been little (if any) empirical analysis justifying the change in the first place. It seems presumptuous to require market participants to justify a return to the commonly accepted approach when there has been no justification to move in the first place.

For a TNSP, the components of revenue recovery are typically as follows:

- entry charges for generators 5%, recovered as fixed charges;
- exit charges (dedicated to the load and distributor connections concerned) 35%, recovered as fixed charges;
- locational TUoS charges 30%, generally recovered as a peak demand or energy component;
- Common Service and TUoS General charges 30%, recovered on a postage stamp basis;

It follows there would be a very significant dilution of the surplus payment which derives from energy charges in the market, if it were to be returned across all transmission price components.

It is also important to consider the source of the settlement surplus funds. Surpluses arise through customers paying higher energy charges than generators receive in an adjacent region. Logically, it is appropriate for the funds to be returned to those customers through a

[1] AEMC Draft Determination p38
[2] IBID p39
[3] AEMC Rule proposal, p56
[4] EnergyAustralia submission to the Rule Proposal p 12, updated using information supplied by TransGrid on 28 November 2006.

rebate on their energy consumption. This is exactly what takes place when the surplus is used to reduce the postage stamped TUoS General/Common Service charges.

Finally, intergenerational issues must be considered. In its development of Rules for Transmission Revenue regulation, the Commission has intentionally sought to limit assets falling under the category of prescribed services to those which contribute to the provision of shared network infrastructure. Assets contributing to the provision of entry services were grandfathered as prescribed under the Rules.

The application of 6A.22.2 will provide a distortionary signal to new connections which will be subject to a negotiated/contestable regulatory regime. They will receive no allocative benefit from the distribution of services from their negotiated charge, while Generators subject to prescribed regulation for their assets will. We believe allocative efficiency is not promoted in this circumstance.

1.2 Meaning of Attributable Cost Share (6A.22.4)

EnergyAustralia applauds the Commission's decision to limit attributable cost share to asset cost reflectivity (rather than broaden the scope to include allocation based on operating and maintenance costs). Nevertheless we reiterate our position that network cost allocation based on asset costs other than the Optimised Replacement Cost (ORC) does not attempt to mimic the network LRMC.

There are a number of alternative approaches available to the TNSP if the Rules allow asset values "referable to values contained in the TNSP's accounts". This includes historic cost, gross restatement value (similar to ORC) net amount (similar to ODRC), building block component, impaired value/recoverable amount, or taxation value. All will result in different values and therefore different allocation issues.

For example, applying a depreciated asset value as the basis for attributable cost share (rather than ORC) would create the following significant issues:

- Prices in newer portions of the network would be higher than those in older parts for exactly the same level of service. Network assets generally have serviceable lives of 40 years or more and in EnergyAustralia's case, a customer supplied via the older 33 kV network would enjoy a lower price than one connected via the generally younger 132 kV network for the same level of service.

- Customers would receive very substantial price increases with the provision of new shared network assets, or when assets were refurbished (whilst all the time enjoying identical levels of network service).

The AEMC's approach may lead to prices which are higher at the start of an asset's life and would decline over the life of the asset. In most instances, this cost profile would directly oppose the profile that would arise from the situation of increasing load throughout an asset's life, which would indicate a higher price towards the end of an asset's life.

Such an outcome runs contrary to the use of efficient prices to signal congestion on the network and the need for further system augmentation. It also ignores intergenerational equity and price shock considerations.

EnergyAustralia therefore asserts that the use of ORC remains the best approach in allocating costs to assets for the purpose of cost allocation, with marginal cost signalling achieved through peak prices.

Appendix 1 contains a worked example using a sample transmission network, which highlights the issues of deviating from the ORC approach currently incorporated in the Rules. This model has been used for pedagogic purposes by the TNSPs since the mid 1990s, to demonstrate the principles involved in transmission pricing.

The AEMC is remiss in advocating pricing principles based on theoretical constructs without considering the likely impact on customers. This model and others are available and need to be used to test the theory. It is unsound and highly unsatisfactory to deliver to institutionalise locational “roof truss” or “saw tooth” pricing trends based on accounting records, and that such an approach could take decades to be fully priced recognising the high likelihood that the 2% side constraint would be binding over that time due to the inappropriately low pricing of the replaced assets.

1.3 Transmission System Assets directly attributable “on a causation basis” (6A.22.4-6A22.5)

EnergyAustralia notes the Commission’s decision to adopt a causer pays principle for prescribed transmission services but is still relatively unsure of how this principle is applied in practice. For the avoidance of doubt, EnergyAustralia would welcome examples of how the cause pays principle would apply to:

- Assets originally built for an entry or exit service but are replaced/augmented due to network reliability requirements, whereupon they would form part of the shared network; and
- Assets originally built for the shared network but are replaced/augmented due to the need to provide an exit service;

These situations are not theoretical: they have happened and will continue to take place from time to time, as the network evolves and its configuration changes. Clarity on how the pricing aspects are to be managed is essential.

In our response to the Rule proposal we noted that the present transmission pricing arrangements were developed over several years with extended consultation as the basis of a national transmission pricing system. The introduction of the clause “on a causation basis” which has no legal or economic foundation only creates uncertainty to generally accepted practice.

We believe the Commission’s concerns about the “confusing mix of … approaches to implement the cost allocation exercise” are addressed in the Rule without the addition of “on a causation basis”. Costs that are directly attributable to a service category are precisely that. Where costs can be attributed to more than one service category, 6A.24.2(d) will apply.

Noting the NGF concerns, there would be more benefit in grandfathering cost allocation to entry services to ensure locational decisions are not distorted than applying causation principles to every new augmentation and replacement.

EnergyAustralia asserted in its response to the Rule Proposal that these Rule changes are likely to involve significant shifts in the allocation of revenue between transmission services and customer classes. This is obviously tempered by Clause 6A.24.4(f) which limits the change in price for the locational component of the TUoS charge to 2% per annum (load weighted).

1.4 Pricing Methodology Guidelines (6A.25.1-2)

EnergyAustralia has long been an advocate of guidelines that provide guidance for TNSPs to assist its compliance with the Rules. As such, the guidelines themselves should not place compliance obligations on the TNSP that are additional to the Rules. EnergyAustralia proposed that the pricing methodology guidelines be amended to be guidelines for approval of a pricing methodology. The existing CRNP and Modified CRNP approaches would form part of these guidelines

While the Commission has chosen not to accept EnergyAustralia's position, it has provided some limitation on the use of guidelines in the Rule. EnergyAustralia supports the removal of the requirement for the AER to develop further guidelines on CRNP methodology and pricing principles. It was difficult to see how the AER would be in a position to improve on the current process, especially given the tight timeframes.

Nevertheless, EnergyAustralia remains concerned about the role of guidelines in assessing pricing methodologies and the extent to which the AER could, through guidelines, dictate the nature and effect of a TNSP's pricing methodology. Draft clause 6A.25.2 provides that the pricing methodology guidelines may specify or clarify "the form which a proposed pricing methodology is to take". The scope of the term "form" is not clear when used in this context and whilst it may be intended to only refer to presentation aspects of a methodology, it could conceivably extend to specifying the actual methodology (or elements of one) which must be used.

The Rules should not provide scope for the AER, through guidelines, to impose requirements in relation to the nature and effect of the methodology - this should be the preserve of the Rules. This discussed further in the context of the assessment of a TNSPs methodology in section 1.5 below.

This could be overcome by amending the Rule so that the AER prepares *Pricing Proposal Guidelines* rather than *Pricing Methodology Guidelines.* While the drafting distinction may seem trivial, it would remove the ambiguity regarding the AER's role in preparing guidelines and assessing the TNSP's without altering the substance of the Rule.

This amendment would clearly distinguish between the procedural and information requirements which may be the subject of AER guidelines and the principles and requirements of the Rules which apply to the assessment of the methodology.

1.5 Assessment of Pricing Methodologies by the AER. (6A.26)

EnergyAustralia supports the further clarification of the procedure, particularly 6A.26.1(b). However, we are concerned with comments in the Commission's determination dealing with procedure and the AER's ability to accept or reject a pricing methodology.

EnergyAustralia proposed in response to the Rule proposal that if a TNSP is using an established method such as CRNP, provided it satisfies the Rules, the AER should automatically approve the pricing methodology. We concluded the consultation process should therefore only be triggered in the event that a TNSP proposes a new pricing methodology.

The Commission disagreed with this proposal:

> *"The Commission considers that as pricing methodologies are only approved at the start of each regulatory control period, the requirement for consultation should remain. This is because even if the methodology does not change, the appropriateness of it may change as network conditions change over time."*

EnergyAustralia is concerned with the inference that the AER can consult on and determine the appropriateness of a pricing methodology or an important element of one, without further clarity on how this will preserve specific recognition of existing approaches such as that given to CRNP by draft clause 6A.24.3(c). While this inference seems inconsistent with 6A.26.12 and the general approach adopted by the Commission, EnergyAustralia seeks clarification on:

- Whether the AER can refuse a TNSP's pricing methodology on any basis other than consistency with the Rules or administration (ie. non-compliance with guidelines). There would not appear to be any basis for providing that the methodology itself (which should be distinct from information submitted in support of it) can be refused because it does not comply with the pricing methodology guidelines given that the guidelines should be confined to issues of presentation and information rather than substance.;
- Whether the AER is required to make a decision on the appropriateness of a pricing methodology and the basis for such a decision;
- The role of consultation, other than for consistency with Rules and guidelines, particularly where there is no intended change in methodology.

1.6 Publication of pricing methodology and transmission network prices

EnergyAustralia noted in its response to the Rule proposal that the current date of publication of transmission prices by the 15th May each year is too late to be implemented into distribution prices for the coming financial year. In NSW, the jurisdictional regulator IPART requires prices to be submitted by the first Monday in April for approval and it is anticipated that the AER will impose a similar requirement. To achieve this timeframe, DNSPs must allow sufficient time for prices to be approved internally, which usually requires that prices must be completed four weeks before this date, around late February.

To deal with this, EnergyAustralia uses the prior year's transmission prices to set rates for large customers, and relies on preliminary estimates from TransGrid as to the level of revenues likely to be recovered from prices for the following year. Estimated prices versus actual prices can and do vary enough to create significant revenue impacts on EnergyAustralia (see earlier comment on the influence of the settlement surplus). Prices and their associated revenues are in effect implemented one year later, resulting in unnecessary revenue risk for the DNSP and the dilution of any intended transmission pricing signals to large customers.

Requiring TNSPs to publish prices by 15th March each year would allow enough time for DNSPs to include these prices in distribution tariffs for submission to the regulator.

The Commission did not accept EnergyAustralia's proposal:

> *"because the expiry of transmission revenue and pricing determinations can vary over time and between businesses, therefore changes to the Rules may not adequately address all situations. The Commission considers that in instances where a TNSP has not yet finalised prices because it has yet to get its Pricing Methodology approved that it can use draft prices and recover any under or over amount in the following year*[5].

EnergyAustralia believes the intent of the Rules state that the 15th May date has been chosen to allow adequate time for transmission prices to be factored in to distribution prices by DNSPs. The Commission acknowledges that determinations vary over time and between businesses. While changes to the Rule may not address all situations, it also follows that a hard date may not address any.

[5] AMEC Draft determination p63

EnergyAustralia believes there is benefit in allowing flexibility in the date prices are published. A date 3 months prior to the end of a regulatory year or another date agreed between DNSP and TNSP would be more appropriate than current drafting.

1.7 Multiple TNSPs within a region (6A.30.1)

The Commission indicated in its Determination on the draft Rule that it had made amendments to the Rule proposal to ensure where there is a co-ordinating TNSP in a region, the Rules provide that the 'appointing' TNSPs in the region are not required to submit, and have approved, separate pricing methodologies. It appears that this amendment has been provided by way of a note to 6A.30.1. The Commission notes that this is a logical position based on avoiding duplication and ambiguity.

EnergyAustralia considers that the note to clause 6A.30 is opaque at best and is insufficient in clarifying the obligations of appointing TNSPs when preparing their own methodologies. There is no acknowledgement of a different compliance regime applying to appointing TNSPs in either the guidelines development 6A.25 or the procedures for approving and pricing methodology 6A.26.

The submission of price structures is highly dependant on the pricing methodology chosen. However, the Rules are silent on the interrelationship with the co-ordinating TNSP when it is submitting its pricing methodology and the AER when it is assessing the co-ordinating TNSP's application. The rules should expressly make provision for the following matters where a coordinating TNSP has been appointed:

- An appointing TNSP is not required to address the matters specified in draft clause 6A.23(c)(1) when preparing its pricing methodology;
- The coordinating TNSP must provide sufficient information to the appointing TNSPs to enable the appointing TNSPs to understand the basis upon which the coordinating TNSP has allocated the various AARRs and to enable it to prepare its own pricing methodology and replicate the pricing allocation.

This matter should receive careful attention from the Commission, as it is anticipated that over the next five years, there is likely to be other examples of multiple TNSPs within one transmission region.

1.8 Prudent Discounts (6A.27)

EnergyAustralia supports the Commissions approach to prudent discounts.

1.9 TUoS Rebates to Embedded Generators

EnergyAustralia notes the Commission's view that a comprehensive change to the regime for embedded generators is not within the scope of the transmission pricing rules. This is disappointing given the Commission had sought opinion from stakeholders through each consultation round, with no concern raised over scope. It is the TUoS pricing allocation which provides the sole justification for TUoS rebates and these matters cannot be separated so simply.

EnergyAustralia believes the Commission was well progressed in developing a sound policy position on this issue.

1.10 Savings and Transitional Arrangements

EnergyAustralia would like clarification on the intent of the savings and transitional arrangements in the final determination, particularly Clause 11.6.3. We believe the market would also benefit from an illustrative example of how savings and transitional arrangements will apply to generator connection services:

- Committed before 16 February 2006 and subject to prescribed transmission services revenue regulation;
- Committed after 16 February 2006 and before 24 August 2006;
- Committed after 24 August 2006.

Appendix – Impact of Changing the Current Cost Allocation Method for the Transmission Network

The current methodology embedded in the Rules for allocating the Aggregate Allowable Regulated Revenue (AARR) for transmission services to customers is on the basis of the Optimised Replacement Cost (ORC) values of the transmission system assets. This better mimics the network Long Run Marginal Cost (LRMC), in contrast to other allocation methods such as Optimised Depreciated Replacement Cost (ODRC) and Building Block Costs (BB).

The following analysis illustrates the impact on prices in the following circumstances:

- Scenario 1: The cost impact on all customers if the current revenue allocation methodology is moved from an ORC basis to either an ODRC or a BB approach.
- Scenario 2: How system augmentation in one part of the network to cater for increased load by a customer impacts the revenue allocation to all customers based on each of the three methodologies.

For demonstration purposes, a simple sample transmission system with 5 busbars and operating at a nominal 220 kV has been modelled. A schematic diagram of the system is shown in figure A.1. As illustrated, the network is assumed to be comprised of older and newer segments of the network (as is very often the case in real networks).

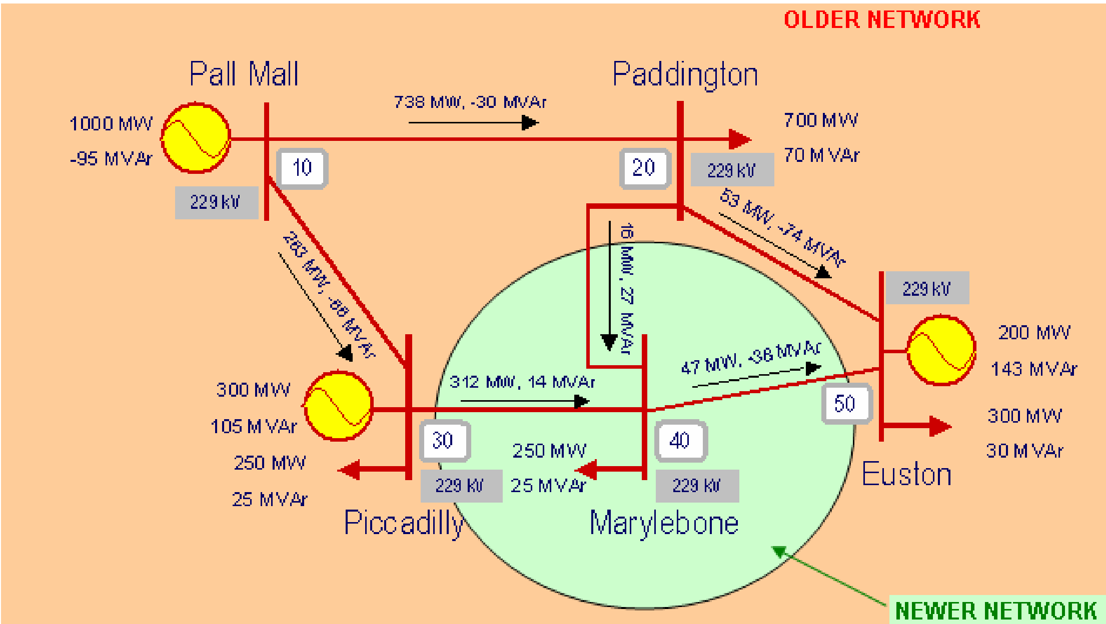

Figure A.1: Sample Distribution System used for analysis

The generated outputs and flows on the diagram are those arising from solution of the load flow with the connected loads. In this model, Pall Mall is the swing or slack busbar and the generators at both Piccadilly and Euston control the voltage. There are four loads in this model: at Paddington; Piccadilly; Marylebone; and Euston. The analysis will measure the pricing impacts at these four customer loads.

The analysis has been completed by modelling the system using TPrice. TPrice is the specialised pricing and loss analysis software used throughout Australia for transmission network pricing and losses, and by EnergyAustralia for its sub transmission network.

Scenario 1: Revenue impact on customers by changing the allocation methodology

To measure the impact of changing the cost allocation method comparisons have been made on the prices charged to the four customers in the model system using each of the three allocation methods:

- ORC
- ODRC
- Building Block (ie. ODRC*WACC + depreciation + opex for each line element).

Initially, it has been assumed that the AARR for this fictitious TNSP is $100M. This revenue is allocated to each of the transmission system assets on the basis of the selected allocation methodology as indicated in table A.1.

Table A.1: Revenue Allocation

Loadflow Circuit		ORC METHOD ('000$)			ODRC METHOD ('000$)			BB METHOD ('000$)		
		LINE	EXIT	TOTAL	LINE	EXIT	TOTAL	LINE	EXIT	TOTAL
From	**To**	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000
PallMall	Padingtn	11,688	7,792	19,481	6,228	4,152	10,381	9,676	6,450	16,126
PallMall	Piccadly	8,442	6,494	14,935	4,498	3,460	7,958	6,988	5,375	12,363
Padingtn	Marylebn	6,169	2,597	8,766	13,149	5,536	18,685	8,742	3,681	12,423
Padingtn	Euston	7,792	649	8,442	4,152	346	4,498	6,450	538	6,988
Piccadly	Marylebn	3,896		3,896	8,304		8,304	5,521		5,521
Marylebn	Euston	3,247	0	3,247	6,920	0	6,920	4,601	0	4,601
REVENUE ALLOCATION		41,234	17,532	58,766	43,253	13,495	56,747	41,978	16,044	58,022
COMMON SERVICES				41,234			43,253			41,978
TOTAL REVENUE				**100,000**			**100,000**			**100,000**

In line with the current rules, 50% of the revenue associated with shared assets is assigned to common services and allocated to customer loads on a postage stamp basis.

The pricing allocation using TPrice with an assumed load and generation profile for each of the allocation methodologies is given in table A.2 below. This indicates that when moving from an ORC to an ODRC method of allocation, there would be a price increase of approximately 32% to customers at Marylebone and a corresponding increase of 36% in the Cost Reflective Network Price (CRNP) component. Given the 2% side constraint applied to the CRNP component of transmission prices it would take approximately 15 years to reach the required price level when the pricing allocation is changed from the ORC to an ODRC method. Conversely, there are price decreases at Euston, Paddington and Piccadilly.

Similarly, when moving from an ORC to the BB method, there is a total increase of approximately 22% at Marylebone. This equates to approximately 10 years before the price will reach the required “cost reflective” level. There are accompanying price decreases at Piccadilly and Euston.

From this simple model system it is evident that there are very significant price changes that would be experienced by the various connected customers if the pricing allocation is changed from the ORC method to either of the ODRC or the BB methods. Due to the side constraint placed on the transmission network pricing, it would be a number of years before the allocated prices can be charged to the customers.

Is should be emphasised that this analysis was carried out using a 50:50 split between the locational component and TUoS general charge. Section 6A.24.3 allows for the proportion of the locational component to be much higher. In such cases, the price change would be even more dramatic.

Scenario 2: Impact on customers if the system is augmented using three allocation methodologies

It is now assumed that there is an increased load from a new customer at Paddington, with the current load of 700 MW increasing to 800 MW. Further, due to the line capacity limitation of the existing connection from Pall Mall to Paddington, a duplicate feeder needs be commissioned to increase the capacity between Pall Mall to Paddington. The resultant system is then similar Figure A.1, but with an additional new feeder from Pall Mall to Paddington. The commissioning of the new feeder has also impacted the total revenue of the assets by $11.5 million, increasing the AARR from $100 M to $111.5 M.

The additional customer load at Paddington was the direct cause of the augmentation. If the costs of augmentation were to be charged in their entirety to that customer under a “causer pays” approach, the additional annual charge of $11.5 M would be recovered from that customer, making its price almost twice that of the remaining load at Paddington (for exactly the same levels of service as the original customers).

To examine the pricing impacts if the new asset is treated as a portion of the meshed network, this revenue is again allocated to each of the transmission system assets on the basis of the selected allocation methodology as was done in Scenario 1.

In this Scenario, the price changes for each of the customers will be examined to determine which if the three allocation methodologies most appropriately allocates network costs taking into account the price shock to customers after a system augmentation occurs.

The results have been summarised in table A.3. These results again enforce that if the allocation approach was changed from the ORC method to either of the ODRC or BB methods, then it would be a considerable number of years before the prices would increase to meet the required price levels.

As the system augmentation is caused by incremental customer load at Paddington, it is appropriate and equitable that all customers at this location should bear a major portion of the incremental revenue, with minimal effect to the other customers. The results of the analysis indicate that this is indeed the case using the ORC method as shown in table A.4.

Table A.4: Price Changes per customer if a system augmentation occurs

	% Differences From Scenario 1 to 2		
	With ORC	WITH ODRC	With BB
Euston	3.85	2.09	3.12
Marylebone	-3.56	11.01	-6.34
Paddington	26.55	37.59	30.52
Piccadilly	-0.16	-8.63	-3.56

Whilst the customers at Paddington are the main beneficiaries of the increased capacity provided by the augmentation, the increased capacity and reliability afforded by this new line would benefits all customers in the meshed transmission network.

It is apparent that the costs of the line are mainly allocated to the customers at Paddington, with smaller changes at other locations. However it must be noted that the ODRC and BB cost allocation methods greatly increase the price change at Paddington, illustrating again that these approaches provide higher prices in new portions of the network.

The 2% side constraint on prices would apply in all instances, but it is clear that if the current ORC method were changed to either the ODRC or BB method it would be many more years before the prices stabilise to the appropriate “cost reflective” levels.

Table A.2: Scenario 1 results for cost allocations for each of the three methodologies

		ORC				ODRC				BB				Differences	
Loads	**Energy GWH**	Line $,000	Exit $,000	CSC. $,000 ($/KWh)	Total $,000	Line $,000	Exit $,000	CSC $,000 ($/KWh)	Total $,000	Line $,000	Exit $,000	CSC $,000 ($/KWh)	Total $,000	% Change ORC to ODRC	% Change ORC to BB %
				5.05				5.30				5.14			
Euston	1275.3	10,693	649	6,445	17,787	10,381	346	6,761	17,488	10578	538	6,561	17,677	-1.7	-0.6
Marylebone	1716.4	8,556	2,597	8,674	19,827	11,660	5,536	9,099	26,295	9700	3,681	8,831	22,212	32.6	12.0
Paddington	3807.6	16,486	7,792	19,242	43,520	16,511	4,152	20,185	40,848	16495	6,450	19,590	42,535	-6.1	-2.3
Piccadilly	1359.9	5,499	6,494	6,873	18,866	4,701	3,460	7,209	15,370	5205	5,375	6,997	17,577	-18.5	-6.8
Total	*8159.2*	*41,234*	*17,532*	*41,234*	*100,000*	*43,253*	*13,494*	*43,253*	*100,000*	*41,978*	*16,044*	*41,978*	*100,000*		

Table A.3: Scenario 2 results for cost allocations for each of the three methodologies

		ORC				ODRC				BB				Differences	
Loads	**Energy GWH**	Line $,000	Exit $,000	CSC $,000 ($/KWh)	Total $,000	Line $,000	Exit $,000	CSC $,000 ($/KWh)	Total $,000	Line $,000	Exit $,000	CSC $,000 ($/KWh)	Total $,000	% Change ORC to ODRC	% Change ORC to BB %
				5.06				5.22				5.12			
Euston	1275.3	11346	676	6,450	18,472	10,867	324	6,663	17,854	11,157	538	6534	18,229	-3.3	-1.3
Marylebone	1716.4	7736	2,703	8,681	19,120	9,244	5,188	8,967	23,399	8,329	3,681	8794	20,804	22.4	8.8
Paddington	4683.6	21419	9,965	23,689	55,073	23,395	8,339	24,469	56,203	22,196	9,325	23995	55,516	2.1	0.8
Piccadilly	1359.9	5198	6,759	6,878	18,835	3,697	3,242	7,105	14,044	4,608	5,375	6967	16,950	-25.4	-10.0
Total	*9035.2*	*45699*	*20103*	*45699*	*111,501*	*47203*	*17093*	*47,203*	*111499*	*46,290*	*18,919*	*46,290*	*111,499*		