ERM
Power for generations

31 January 2012

Robert Pullella
Executive Director Access
Economic Regulation Authority
PO Box 8469
Perth BC
WA 6849

Dear Robert,

Re: Submission to the ERA – Revision of the Generator Transmission Use of System Charges in Western Australia

Thank you for the opportunity to meet with you and your staff to discuss our issues with the current allocation of 20% of shared network costs on generators (GTUOS) under Western Power's Access Arrangement.

Both ERM and Griffin Power made submissions to the ERA regarding the GTUOS allocation as part of their responses to the ERA's Issues Paper on Western Power's Proposed Revisions to the Access Arrangement.

ERM Power as the Operator of NewGen Power Kwinana and NewGen Neerabup appointed Synergies consulting to draft a paper on the GTUOS charges in terms of meeting the Electricity Network Access Code objectives ("Code Objectives").

Please find the attached paper which clearly demonstrates that the allocation of TUOS costs to generators is not consistent with the Code Objectives and as such should not be approved by the ERA.

Should you have any queries, please do not hesitate to contact me on (08) 9481 1108.

Yours sincerely,

[redacted]

Andrew Sutherland
General Manager WA Projects

cc Tyson Self, Manager Projects Access
Email: publicsubmissions@erawa.com.au

Revision of the Generator Transmission Use of System Charges in Western Australia

A report for NewGen

24 January 2012
Synergies Economic Consulting Pty Ltd
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Disclaimer

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In conducting the analysis in the report Synergies has used information available at the date of publication, noting that the intention of this work is to provide material relevant to the development of policy rather than definitive guidance as to the appropriate level of pricing to be specified for particular circumstance.

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1 Introduction

NewGen Power Kwinana and NewGen Neerabup ('NewGen') have asked Synergies Economic Consulting ('Synergies') to prepare a submission for the Economic Regulation Authority ('ERA') which sets out the shortcomings of Western Power's current arrangements for setting transmission use of system ('TUOS') charges, in terms of its failure to meet the objectives of the *Electricity Network Access Code 2004* ('the *Code'*). The submission then identifies an alternative pricing model that meets the objectives of the *Code*.

Western Power has adopted access prices for transmission that comprise three basic components:

- shallow connection charges sufficient to cover the costs of connecting load or generation to the transmission network, allocated directly to the connected party;
- recovery of shared transmission costs (predominantly transmission asset related cost other than those covered by connection charges) allocated 80% to load and 20% to generators; and
- other common services costs such as voltage control assets, allocated to load.

This submission solely addresses transmission pricing arrangements in the Western Australian Interconnected System ('SWIS'), and primarily addresses the allocation of 20% of shared transmission costs to generators.

Western Power's current TUOS charge to generators ('GTUOS') is unique in this respect as it has not been adopted by any other transmission network service provider ('TNSP') in Australia. Based on Western Power's proposed revised access arrangement (dated 30 September 2011) this approach is proposed to continue for the 1 July 2012 to 30 June 2017 regulatory period.

The current allocation of 20% of total shared network costs to generators in GTUOS does not meet the objectives of the *Code*. The allocation is essentially arbitrary. Removing the obligation on generators to pay GTUOS and re-allocating the shared network costs to load will meet the *Code* objectives, primarily because it will enhance efficient consumption of power and enhance incentives for generators to provide capacity. There is ample precedent for this pricing framework in Australia and elsewhere.

The potential inefficiencies of Western Power's pricing framework will be realised over time. As the regulatory framework (in the form of the *Code*) and the wholesale electricity market in the SWIS are recent developments, introduced in 2004 and 2006 respectively, the inefficiencies that are likely to arise from the GTUOS arrangements may not yet be apparent. They will increase in the future.

1.1 Structure of the report

The report is structured as follows:

- Section 2 sets out the legislative considerations and the objectives of the *Code*;
- Section 3 briefly summarises the Western Australian power market and then sets out current transmission pricing arrangements;
- Sections 4 deals with the cost characteristics of transmission and, having regard to those characteristics and the objectives of the *Code*, sets out criteria for the design of a pricing framework;
- Sections 5 sets out some of the different pricing models and principles that used in transmission pricing in other jurisdictions, and illustrates them briefly with Australian and overseas experience;
- Section 6 sets out the deficiencies of GTUOS in respect of the *Code* objectives and suggest an alternative pricing framework for Western Australia that better meets those objectives; and
- Section 0 presents brief conclusions.

2 Legislative considerations

The *Code* sets out the functions and powers of the ERA in assessing Western Power's proposed revised access arrangement.

In accordance with section 4.28 the *Code*, when considering a proposed access arrangement, the ERA must determine whether it satisfies the *Code* objective and the requirements set out in Chapter 5 in respect of content and Chapter 9, if applicable, in respect of the regulatory test. If it does satisfy these, the ERA must approve the proposed access arrangement. Furthermore, the ERA should not refuse to approve a proposed access arrangement because it considers that some other form of access arrangement might be even better, or more effective, at meeting the Code obligations.

2.1 Overall objectives

Section 2.1 of the *Code* states that (emphasis in the original):

> The objective of this Code ("**Code objective**") is to promote the economically efficient:
>
> (a) investment in; and
>
> (b) operation of and use of,
>
> *networks* and *services of networks* in Western Australia in order to promote competition in markets upstream and downstream of the *networks*.

Section 2.2 states that the ERA must have regard to this *Code* objective when performing its functions under the *Code*.

The concept of efficiency, widely adopted in Australian regulatory precedent in respect of access regimes of this type, accords with three aspects of economic efficiency: that prices should reflect costs (*allocative efficiency*); that costs should be efficiently incurred in the short and long term (*productive efficiency*); and that appropriate levels of innovation occur sufficient to engender efficient changes and improvements over time, including cost reductions (*dynamic efficiency*). For example, the Australian Competition Tribunal stated that the concept of efficiency moves beyond the question of whether the operator can recover all its costs, but should encompass the economist's notions of allocative, productive and dynamic efficiencies.[1]

1 *Telstra Corporation Ltd (No 3)* [2007] ACompT 3, at [171].

Efficiency in the provision of transmission services is not an end in itself, but for the purpose of promoting competition in the upstream and downstream market, the most significant of which is the market for power generation and the market for power retailing. Competition is not an end in itself, but is rather a means of delivering efficient outcomes. Hilmer noted that:[2]

> The promotion of effective competition and the protection of the competitive processes are generally consistent with maximising economic efficiency…
>
> Competition policy is not about the pursuit of competition for its own sake. Rather, it seeks to facilitate effective competition in the interests of economic efficiency while accommodating situations where competition does not achieve economic efficiency or conflicts with other social objectives.

In broad terms, then, the overall objective of the *Code* is to foster allocative, productive and dynamically efficient provision of power, relying to a greater degree on competition in those segments of the market that can sustain workable competition and on regulation where this is not the case. Given the highly integrated nature of the power market, necessitating very close coordination between generation, transmission and load, assessment of an access regime in terms of the *Code* objectives should examine whether it results in efficient overall outcomes, that being the goal of both regulation and workable competition. This submission assesses Western Power's transmission prices against this broader efficiency goal.

2.2 Pricing objectives

Section 8.1 of the *Code* requires that Western Power submit "Price List Information" to the ERA when it submits an Access Arrangement. Section 1.2 defines "Price List Information" as:

> A document which sets out information which would reasonably be required to enable the Authority, users and applicants to:
>
> (a) understand how the service provider derived the elements of the proposed price list; and

[2] Hilmer et al. 1994, *National Competition Policy* (Australian Government Publishing Service) ('*Hilmer* Report') at 5, 6. Available at http://www.ncc.gov.au/images/uploads/Hilmer-001.pdf last viewed 23 January 2012.

(b) assess the compliance of the proposed price list with the access arrangement.

The ERA annually reviews the compliance of network prices with the price control and pricing methods in the approved Access Arrangement. Section 8.2 of the *Code* states that (emphasis added):

> If the Authority considers that a service provider's proposed price list complies with:
>
> (a) the price control in the service provider's access arrangement; and
>
> (b) the ***pricing methods*** in the service provider's access arrangement,
>
> then the Authority must:
>
> (c) approve and publish the service provider's proposed price list which has effect from a date specified by the Authority; and
>
> (d) publish the service provider's price list information.

"Pricing methods" in this context refers to the structure of reference tariffs included in the access arrangement, which determines how the maximum revenue is allocated across and within reference services. The objectives of the pricing methods under the *Code* are as follows:

- section 7.3 sets out the primary objectives of the pricing methods that: the reference tariffs recover the forward-looking efficient costs of providing reference services; and the reference tariffs do no result in cross-subsidies between users or groups of users, by stipulating that the tariff applying to a user recovers an amount of revenue that is greater than the incremental cost of service provision and less than the stand-alone cost of service provision;
- section 7.4 sets out other pricing objectives: that differences in charges to users should differ only to the extent necessary to reflect differences in the average cost of service provision to those users; that they meet the reasonable requirements of users (to the extent that they remain consistent with the objective of the *Code*); that they are predictable; and they do not result in price shocks; and
- the *Code* also:
  - requires geographically uniform 'postage stamp' transmission prices for connected contracted load below 1MVA (section 7.8);

- accommodates discounting where it is necessary to aid economic efficiency (section 7.9);
- allows discounts for generation connected at typical distribution network voltages (66kV or less) to the extent that such generation generates capital or operating costs on the network;[3] and
- stipulates incremental costs should vary with usage, fixed costs should not vary with usage, unless an alternative arrangement better meets the objective of the code.

3 Generation connected to the distribution network can often reduce the need for transmission network augmentation and/or voltage support (reactive power), both of which can lead to transmission cost savings.

3 Summary of the current arrangements

3.1 The Western Australian Interconnected System

The Western Australian power market comprises three distinct electricity networks which are not interconnected: the SWIS; the North West Interconnected System ('NWIS'); and Esperance System. In September 2006, the Western Australia Government introduced a wholesale electricity market in the SWIS.

The market has much in common with the competitive electricity market established in Texas in the US, being primarily focused on supporting the transaction of bilateral contracts for power between buyers and sellers which are not traded through a centralised power pool (in contrast to, for example, the National Electricity Market ('NEM') operating in the eastern Australian States). The operation of these bilateral contracts is supported by a day-ahead short term energy market ('STEM') and a balancing market energy market. Figure 1 briefly summarises the main differences between the SWIS market and the NEM.

Figure 1. Comparison of Western Australian power market with the NEM

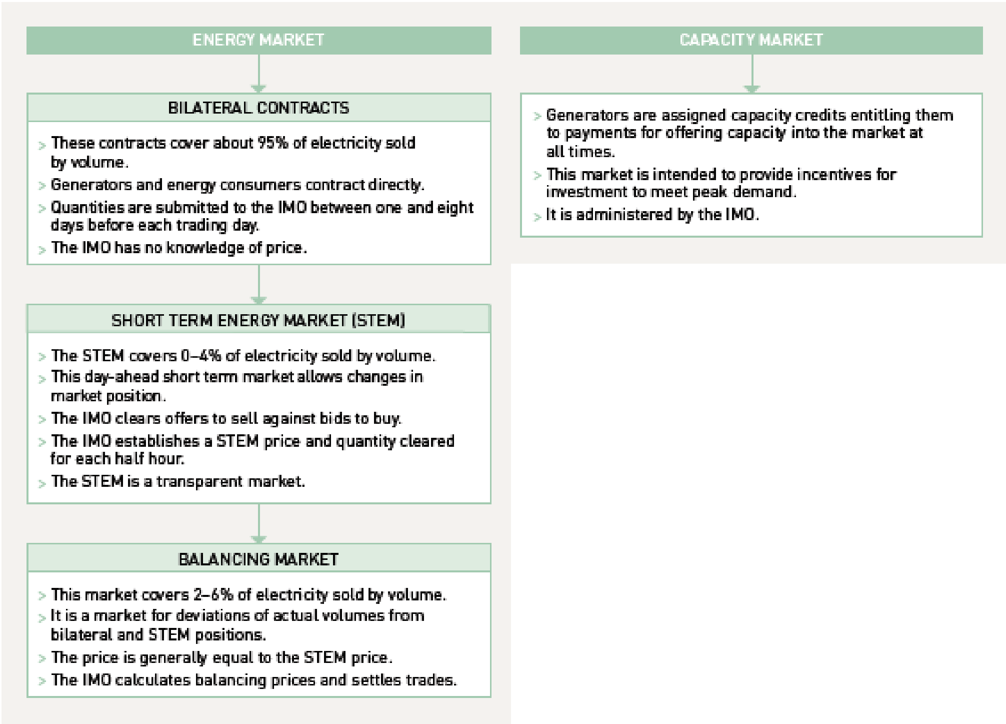
Wholesale Electricity Market	National Electricity Market
Reserve capacity mechanism	No capacity mechanism
Net market	Gross Spot Market
SRMC Based Market Caps (~$336/$546/MWh)	Market Based Spot Cap ($12,500/MWh)
Ex-ante market	Real Time Market
No market control of generation	Direct Market Control of Generation
No nodal dispatch or transmission model	Nodal Dispatch with Complex Transmission model

Source: IMO Investor Information Session, Allan Dawson 28 July 2011, slide 9.

3.1.1 Market and system operation

An Independent Market Operator ('IMO') was established to administer and operate the wholesale market for power that was not traded bilaterally. It also conducts long term (10 year) generation adequacy planning, amongst other things, to support the Reserve Capacity Mechanisms

Figure 2. Main components of the SWIS wholesale market



Source: IMO

System Management, a ring-fenced business unit of Western Power physically operates the SWIS system.[4] The system operator conducts short and medium term system planning, including outage planning. It schedules Electricity Generation Corporation resources, while respecting Independent Power Producer (IPP) transactions. In real time it dispatches the power system, and can only change IPP schedules under special circumstances.

3.1.2 Market participants

In the SWIS the following are licensed participants:

- Electricity suppliers
    - Synergy (Government owned)
    - Alinta
    - ERM Power Ltd

[4] For a useful summary see Independent Market Operator, October 2006, *The Southwest Interconnected Wholesale Electricity Market: an Overview* available at http://www.imowa.com.au/f214,89527/ShortBrochure.pdf last viewed 23 January 2012.

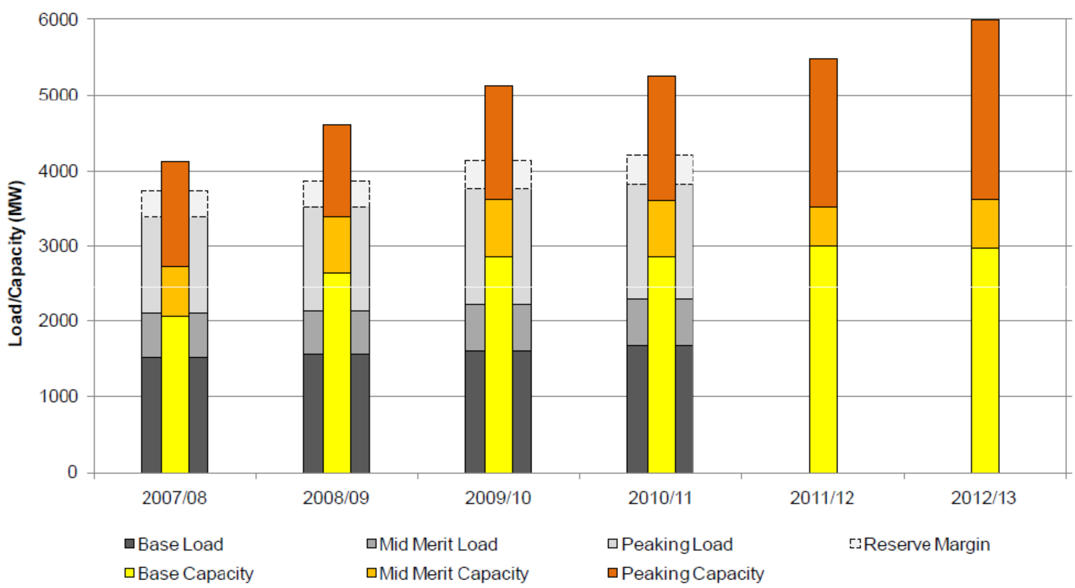
- Griffin Energy
- Landfill Gas and Power Pty Ltd
- Perth Energy
- TransAlta
- Westfarmers Premier Power Sales Pty Ltd
- Worsley Alumina Pty Ltd

- Electricity generators
  - Verve Energy (Government owned)
  - ERM Power Ltd
- Electricity Networks
  - Western Power (Government owned).

3.1.3 Supply and demand in SWIS

Figure 3 below briefly summarises the evolution of supply demand balance between generation and load in SWIS since 2007/08, and anticipated supply in 2012/13.

Figure 3. Load and generation in SWIS



Source: IMO

3.2 Western Power 2011-12 Price List

Section 9.4 of Western Power's Access Arrangement[5] sets out the pricing methods (cost allocations), which Western Power has used to meet the objectives of the *Code* as follows.

> Overview of Pricing Method
>
> 9.4 Reference tariffs are derived from an analysis of the cost of service provision which entails:
>
> (a) identifying the costs of providing reference services;
>
> (b) allocating the costs of providing reference services to particular customer groups;
>
> (c) translating the costs of serving particular customer groups to the costs of providing reference tariffs; and
>
> (d) determining a structure of reference tariffs in a manner that reflects the underlying cost structure, in accordance with section 7.6 of the Code.

The approach that Western Power uses for determining prices is set out in more detail in the 2010/11 Price List and Price List Information.[6]

Cost Pools

Western Power's prices are derived from three cost pools:

- the Connection Services Cost Pool, further sub-divided into costs for entry points and costs for exit points, which contain costs associated with connection from the generation/load (respectively) to transmission network;
- Shared Network Services Cost Pool, which in essence contains all network costs other than connection costs, SCADA and SCADA communication costs; and
- Control System Services Cost Pool, which SCADA and SCADA related and communication costs.

5 Western Power, 24 December 2009, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power* http://www.westernpower.com.au/documents/aboutus/accessarrangement/2010/WE_n6734262_v1A_AA2_-_Agreement__Main_Doc_.pdf last viewed 23 January 2012.

6 Western Power, April 2011, *2010/11 Price List.* Western Power, April 2010, *2010/11 Price List Information* both available at http://www.westernpower.com.au/aboutus/accessArrangement/Networkaccessprices.jsp last viewed 23 January 2012.

The details of and allocation of these cost pools are set out in Chapter 4 of the *2010/11 Price List Information*. In summary, network assets are allocated to each of these cost pools and valued using a Gross Optimised Deprival Valuation ('GODV). The revenue needed to compensate each cost pool is then determined on the basis of an appropriate return on and return of capital and recovery of operating costs. The details of the revenue calculation are not germane to this submission, other than to note that the prices charged to each class of customers (load or generators) connected to the network are a function of the proportional share of these pools allocated to each class. Rather, this submission principally deals with Western Power's allocation of the total Shared Network Services Cost Pool, and in particular the allocation of 20% of that pool directly into generator TUOS ('GTUOS').

4 Pricing and cost characteristics of transmission

4.1 Economic objectives of transmission pricing

It is accepted in the economic literature that the objectives of transmission pricing encompass a wide range of factors and elements aimed at encouraging certain types of behaviour by network users and classes of users. For example, prices should:

- send efficient economic signals, across both a short and long term horizon, to:
    - promote the efficient day-to-day operation of the bulk power market;
    - signal locational advantages for investment in generation and demand; and
    - signal the need for investment in the transmission system;
- recover the approved regulatory costs of the transmission network;
- not discriminate between users and classes of users unless that discrimination fosters efficient outcomes; and
- be simple and transparent.

There are a number of elements to consider when developing an economically efficient pricing framework:

- Productive (technical) efficiency. This is achieved where output is produced at the lowest possible cost. In order for this to occur, available economies of scale and scope must be realised.
- Allocative efficiency. This is achieved where available resources are allocated to their most highly valued use, an outcome that is best achieved when prices reflect the costs of supply.
- Dynamic efficiency. This is achieved when resources are allocated to their highest valued use over time, particularly in terms of encouraging innovation and the optimal location and timing of investment.

In economics, first-best pricing, that which all other things being equal results in efficient allocation of and use of resources in the short term,[7] requires that the price of goods and services are set at marginal costs. This creates problems when, as is

[7] Which means that that revenue is always equal to cost, and that all customers willing to pay the marginal cost obtain supply.

commonly the case, revenue from marginal cost pricing is insufficient to remunerate fixed costs. Economists have therefore developed second-best pricing approaches whereby any revenue shortfall necessary to ensure that service provision is economically viable, is recovered with the least possible distortion of production and consumption decisions relative to first-best pricing.[8] This pricing outcome would be expected to arise in the overall power market in SWIS if the network access regime meets the *Code* objectives and promotes (in the sense of results in) workable competition in upstream and downstream markets.

Allocative efficiency in transmission prices generally requires that prices reflect costs that arise as a consequence of the consumption of transmission services, in order for the network users and prospective users to determine whether the benefits they derive from network usage exceed those costs. Under such a pricing paradigm, the network user would only choose to use the network service if this was the case.

Furthermore, in the circumstances of power markets, where upstream and downstream markets are dependent on transmission, transmission pricing should result in efficiency in those markets. The *Code* objectives indicates that this should arise through the promotion of competition in those markets, which necessitates that transmission prices should not distort behaviour (including production, consumption and investment decisions) in those related markets.

4.2 Cost and benefit drivers

This basic pricing principle, that prices should be based on the costs, imposes substantial challenges in the context of determining prices for transmission services.

The direct cost characteristics of transmission are relatively simple. In common with most infrastructure services, the costs are predominantly fixed deriving from the transmission assets (lines, substations etc.) themselves. These assets are long-lived and generally difficult to redeploy once installed. Hence, transmission investment costs are generally sunk. At the simplest level, the quantum of network assets required are a function of the peak power that has to be transmitted across the network, the required level of reliability of the overall power system, the disposition of generation and load across the network and, to some degree, the characteristics of that load or generation.

However, the complexity of transmission cost causality lies in the inter-relation of the transmission service itself and the operation of the generation and retail supply

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8 This criterion is generally achieved when goods and services are allocated to those user that value them most highly.

markets that depend upon it. For example, at the level of the marginal costs of transmission:

- transmission of power results in power losses that are a function of distance of transmission, voltage, conductor size and type, use of AC or DC technology, power factor etc.;
- marginal losses, being the additional losses that result from a marginal increase in transmitted power, tend to increase with the square of the power;
- power flows on synchronous networks are not easily controlled but are a consequence of the physical structure of the network, its topology, and the disposition of generation and load across it, the latter two which can change rapidly. Power flows rarely align precisely with power contracts between generators and customers;
- parallel network paths, which are often essential for ensuring network security in the event of contingencies, can give rise to loop flow constraints which, in turn, can result in apparently perverse changes in network costs in response to changes in load and generation disposition;
- network security requires a degree of redundancy in transmission networks in order to manage contingencies (such as a failure of a transmission element or a connected generator) and unexpected peaks in power demand. The occurrence of a contingency can significantly change marginal transmission costs;
- network capabilities and costs can be affected by the level of services available from generators such as voltage support, out-of-merit operation and reserve both on geographically specific and network-wide bases, which can vary over the short term;
- most transmission assets are used by more than one network user; while there are approaches for apportioning usage to network users (for example, on the basis of power flow studies), they are difficult to implement, somewhat volatile, and it is doubtful whether they reflect the economic value that network users place on the assets.

Furthermore, social efficiency requires that the market and pricing framework across the integrated power market should achieve efficient outcomes, with the result that economic efficiency cannot be considered at the level of the transmission network service provider alone. For example:

- there is inevitably a trade-off between the costs of transmission to meet the requirements of remote generation, and the costs of being able to locate a new generation resource where fuel costs are low;[9]
- choices by one network user can change the costs faced by other network users. For example:
    - increased levels of wind generation attached to a network can increase the demand for peak transmission capacity and non-renewable generation to cover for the correlated contingency of wind generation failure; and
    - new generation or load locating at a network node can change/affect the level of transmission capacity available to other network users; and
- investment and even operating decisions are affected by a variety of external factors including:
    - planning constraints that severely limit where new transmission and generation assets can be located;
    - environmental and related constraints; and
    - community concerns.

In addition, transmission and distribution networks exhibit network and scale economies sufficient to endow them as natural monopolies. Accordingly, competition between TNSPs in a single power market would result in substantial productive inefficiency (in the form of unnecessary duplication of assets), but a single provider will possess significant market power. Absent constraints, this market power would result in inefficient monopolistic behaviour.

4.3 Pricing in practice

For the foregoing reasons it is, both from the theoretical economic perspective and as a matter of commercial practice, difficult to design a transmission pricing framework

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9 Similar considerations can sometimes (but less often do) arise in respect of the location of new load.

that meets the efficiency objective set out in the *Code*. Hence, as a practical matter, transmission network operation, investment and pricing universally fall under some form of technical and economic regulation which collectively aim to prevent socially inefficient outcomes.

The principal influence on productive and dynamic efficiency is the form of regulation together with the treatment of productivity gains at the regulatory reset, the nature of the provisions covering the rolling forward of the asset base and the treatment of any contribution towards economic efficiency. Therefore the focus on economic efficiency in network prices is usually on the allocative efficiency component in the shorter term and generator location and dynamic efficiency over the longer term.

4.3.1 Cost reflective network pricing and short-run pricing

Notwithstanding these complexities, there are examples, both domestically and internationally, of power markets that have adopted pricing models that reflect some of these transmission cost-causation factors.

Nodal pricing

The most sophisticated short-run pricing models in operation globally are based on nodal prices, where the short-term price of power is determined for each point of interconnection with the network. It is beyond the scope of this submission to go into the details of nodal spot pricing in power markets, but it is sufficient to note that the spot price at each node:

- includes an component that reflects the market value of the increase or decrease in marginal losses on the overall network that would arise as a result of an increase in power injections or power withdrawals at that location; and
- can include a congestion component, in so far as increased injections or withdrawals at the node result in elements of the transmission network becoming congested (i.e. reaching their secure capacity).

As a result, differences in the spot prices at different locations in the network can help to signal the value of transmission between those locations. Furthermore, surpluses can arise, which are sometimes termed congestion rents, when elements of the transmission network become congested, such that a difference in nodal price develops between points of ingress and points of egress. These congestion rents can be used to remunerate TNSPs.

Inter-regional interconnection

A less sophisticated pricing framework, which has been adopted in the NEM, separates the interconnected market into discreet zones, where a uniform spot price[10] applies in each zone, but where spot price differentials are allowed across the interconnections between the zones. As with nodal pricing, the price differential across the interconnects can help signal the value of the interconnections, and the rent that accrues as a result of the differentials can accrue to the interconnection owner.

Geographically differentiated TUOS and connection charges

A number of markets have adopted TUOS charging frameworks that are differentiated on a geographical basis, such that the charges in each defined location reflect, to some degree, the cost consequence for the TNSP of power injections or withdrawals at that location. Examples include the UK and several South American markets (see section 5.2 on page 28 for details).

4.4 Causation, 'beneficiary pays' and socialised costs

There are several conceptual frameworks for allocating transmission costs across network users and locations.

4.4.1 Cost causation

As noted above, in order to promote allocative efficiency, transmission prices should generally be based on cost causality principles. That is, a network user should face prices that reflect the costs that the behaviour of that user imposes on the overall power system. To the extent that these costs can be separated into costs related to the upstream and downstream markets (e.g. spot power prices), the residual can be considered to be transmission related costs. For the reasons set out above, this can be a very complex and difficult task.

This approach may be difficult to apply in practice as it may not be possible to allocate transmission costs to individual users solely on the basis of causation. This is especially the case for costs associated with the shared meshed network, as it:

> …exhibits strong externalities (both positive and negative) associated with transmission use and relatively high transaction costs for

10 While there is a uniform spot price, this is often adjusted by a static loss adjustment factor to take account of network losses. These loss adjustment factor can differ across nodes.

internalizing these externalities. In these circumstances, the causal link between *individual* network users' decisions and the incurring of transmission costs may not be clear[11].

4.4.2 The beneficiary pays model

The beneficiary principle is a derivative of the allocative efficiency rule which states, broadly, that the party that benefits from the existence of a particular transmission element should be allocated the costs of that element. There are two generally adopted approaches to determining how a network user might benefit from the asset:[12]

- an approach based on load flow modelling which examines the extent to which power flows on network elements change in response to changes in injections or withdrawals and different nodes on the network. These coefficients are known as distribution factors. The costs of each network element can then be apportioned to nodes (and to load and generation at those nodes) on the basis of the distribution factors. The approach has the desirable feature that allocations to nodes tend to be greater when load or generation at that node is more likely to cause network congestion and therefore to necessitate new network investment; or
- a second approach can be adopted when locational marginal prices ('LMP')[13]/ nodal prices or through the use of market simulation tools that can estimate location specific prices. Under this approach, the benefit at each location in the network is determined as the change in price (or power cost) at that point that results from a change in the capacity of a network element or by the addition of new network capacity.

These approaches also present significant difficulties. To some extent they take account of positive and negative externalities that are intrinsic to network operations, such as loop flow constraints, because they are generally based on accurate models of the power system.

However, it is doubtful whether the allocation accords with the *economic* benefits that derive to users of the network. Power flows alone do not equate with benefits since the

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11 AEMC. 2006. *Rule Determination: National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No. 22.* 21 December. pp 21.

12 For a helpful summary of these issues see PJM, March 10 2010, *A Survey of Transmission Cost Allocation Issues, Methods and Practices.*

13 LMP is the terminology used in the PJM power market in the US which is the best known example of a wholesale market based on nodal spot prices.

benefit that a network user derives is a function of the value of the power generated or consumed, not simply the quantum. That value can vary profoundly between network users, across location, across time of day and year. An approach based on nodal prices is, potentially, superior but will inevitably rest on assumptions about future market behaviour.

In economic terms, the benefit that load derives from power is equal to the consumer surplus they secure from it, being the difference between their willingness to pay for the power and the price they are required to pay. The benefit for generators is usually equal to the operating profit they derive from their power sales, which in a competitive market is usually a commercially confidential matter. Typically, neither the load flow approach nor the LMP based approach results in estimates of benefit to the user that are consistent with benefits in the economic sense. .

The term 'ultimate beneficiary' has sometimes been used in consideration of transmission cost allocation,[14] which is meant to convey the idea that load or the power consumer is the only 'real' beneficiary of the power system. It is the case that ultimately, if the market is to work efficiently, revenue from final customers must be sufficient (and just sufficient) to cover all the efficient costs of supply. However, simply because goods and services are produced to meet customer demand, should not lead to the conclusion that all transport costs in the supply chain should automatically be allocated to customers (which is the sense in which 'ultimate beneficiary' is sometimes used).

The choice over allocation should be based on economic efficiency principles (noting that these principles align with the *Code* objectives). In the case of shared transmission costs, there are compelling reasons for allocating costs to load (i.e. ultimate beneficiaries), but this does not rest on the fact that final customers must, in the end, remunerate all efficiently incurred costs, but rather that the approach of direct allocation is most likely to foster efficient outcomes (and in turn, better advance the objectives of the *Code*).

4.4.3 Socialising network costs

The idea of 'socialising'[15] costs generally refers to the allocation of transmission costs to network users without regard to notions of causation or benefit outlined above. Generally, this has come to mean the allocation of shared transmission costs across all

14 It was also widely used in submission to NEMMCO in its consultations on charges.

15 The term socialisation is sometimes used pejoratively, particularly in the US, in that it connotes inefficiency, failure of user pays principles and cross-subsidy. However, this implicitly attaches efficiency benefits to the alternatives which, in practice, may be illusory.

users (or all users of a particular class, such as generation or load) without regard to location, power flows or spot market performance. Most often, this involves somewhat arbitrary allocation of shared network costs to load and to generation, based on the peak demand of load and the rated connection capacity of generation.

4.5 Pre-requisites

Whether a particular pricing framework delivers efficient outcomes depends crucially on the circumstances of the market in which it is imposed, the characteristics of the pricing model that is adopted and the ability of participants to respond. In particular:

- participants in the market must be able to observe the transmission price;
- the price must reflect the social costs that arise from the consumption of the transmission service;
- the pricing schema must be robust, such that it still encourages efficient responses in the future as market circumstances change;
- network users or prospective network users must be able to respond to the price in a manner that result in enhanced efficiency (relative to the situation where they cannot respond);
- the transaction costs associated with the pricing scheme must be small in comparison with the efficiency gains that derive from it.

Western Power's approach to TUOS as discussed in the context of these in section 6 below, after first briefly discussing approaches adopted elsewhere.

5 Domestic and international trends in pricing

5.1 Transmission pricing in the Australian NEM

5.1.1 Network costs

The NEM transmission system is a shared open access network to which shallow connections charges apply. This means any qualified party can interconnect to the network, subject to a connection charge that solely covers the costs of their connection to the grid (a charging concept widely referred to as a ***shallow connection charge***).

The costs of all shared assets in the network (i.e. those not solely dedicated to the connecting party) are recovered from all network users through TUOS. Hence, if a new generator or new load connects to the network necessitating augmentation of shared assets in order to maintain system security, reliability and economically efficient transmission services, those augmentation costs will be included in TUOS and not charged to the specific network user.[16]

It is important to note that the incorporation of shared assets (or augmented shared assets) into the pool of costs for TUOS is subject to an economic benefit test.[17] If the test is not satisfied in respect of augmentation to meet the needs of a connecting party, that party may choose to pay for the augmentation itself. However, this does not confer any property rights for the party over the additional transfer capacity.[18] In the absence of this election, the augmentation will not occur.

5.1.2 Allocation of shared network costs

In the context of the recent reforms to the regulation of the NEM, the Australian Energy Market Commission ('AEMC') was required to conduct a review of the revenue and pricing rules that apply to the regulation of electricity transmission network services. This review guided the drafting of Chapter 6A of the National Electricity

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16 There are transmission pricing models that require new connecting parties to pay some or all of the shared asset augmentation costs. These are commonly referred to as imposing ***deep connection charges***.

17 There are also reliability standards that have to be maintained. However, these can be subsumed into the economic benefit test in so far as new connection that gives rise to inadequate reliability is likely to impose a high social cost sufficient to more than offset the costs of the necessary network augmentation.

18 The AEMC is currently conducting the *Transmission Frameworks Review*, which is a review of the arrangements for the provision and utilisation of electricity transmission services in the NEM, with a view to ensuring that the incentives for generation and network investment and operating decisions are effectively aligned to deliver efficient overall outcomes. In November 2011, the AEMC released for comment its First Interim Report, setting out five alternative paths for reforming the role and provision of transmission networks. These range from packages similar to the current arrangements to packages that redefine the rights that generators have to use the transmission network.

Rules ('NER').[19] Under Chapter 6A a TNSP is required to submit to the Australian Energy Regulator (AER)[20] a Revenue Proposal and Proposed Pricing Methodology prior to the commencement of the regulatory control period. Clause 6A.10.1(e) requires the Proposed Pricing Methodology give effect to and be consistent with the Pricing Principles in Part J, Chapter 6A of the NER and with the AER's Pricing Methodology Guidelines.

In these guidelines the AEMC eschewed GTUOS charges. In its final Rule Determination on the pricing rules, the AEMC noted that it had given consideration a number of alternative pricing options including the introduction of GTOUS as part of its consideration of the 'beneficiary pays' approach. As transmission networks facilitate the transportation of power from producers (generators) to consumers (loads) it could be argued that generators benefit from the network as much as loads. Therefore, generators should make a contribution to the recovery of the cost of the shared network, i.e. GTOUS.

However, the AEMC concluded that there was little efficiency benefit to be gained through the imposition of GTOUS at this point in time as[21]:

> Shared transmission investment is primarily undertaken to serve the needs of reliable supply to loads. Further, such a move would represent a profound shift from the existing arrangements and that it is far from clear whether it would be worthwhile. Generator TUOS charges would most likely be ultimately passed on to loads, potentially distorting bidding and dispatch in the process. While the British electricity market and several others do apply generator locational use of system charges, as noted in the Pricing Issues Paper, these markets generally have fewer (or one) pricing regions and different regulatory arrangements governing transmission investment. Finally, the framework for Negotiated Transmission Services allows for Generators to agree to pay TNSPs for services that fall outside the definition of Prescribed Transmission Services adds additional emphasis to this approach.

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19 Australian Energy Market Commission, 22 December 2011, *National Electricity Rules Version 47* available at http://www.aemc.gov.au/Electricity/National-Electricity-Rules/Current-Rules.html last viewed 23 January 2012.

20 This is a new requirement. Whilst the old regulatory requirements for transmission pricing were prescriptive in terms of the administrative process associated with constructing the prices, they did not require a Pricing Methodology be produced by a TNSP.

21 AEMC. 2006. *Rule Determination: National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule No 22.* 21 December. p 22.

In summary, shared network costs in the NEM that satisfy the net economic benefit test (which is the vast majority) are entirely recovered from loads. That is generators only pay connection charges, not TUOS.

5.1.3 Geographical elements of TUOS

Prior to the allocation of shared network costs into the locational and non-locational components, the shared network costs are adjusted for auction amounts arising through the Settlements Residue Auction ('SRAs'). The remaining shared transmission costs, approximately 50% are recovered through non-locational (postage-stamp) charges on loads. The remaining shared network costs are recovered from loads on the basis of locational pricing (i.e. the cost-reflective network pricing' ('CRNP') allocation methodology). CRNP applies load-flow analysis to allocate the costs of various network elements (e.g. lines, substations etc.) to different load connection points based on the extent of which a hypothetical increment of load at each of those points leads to increased flow across the relevant network elements.

Under the NER there is scope for an alternative allocation, compared to the 50/50 split between the locational and non-location components. TNSPs may apply an alternative allocation to each component, to reflect a reasonable estimate of future network utilisation and the likely need for future transmission investment, if such an approach has the objective of providing more efficient locational signals to market participants, market new entrants and end users. There is also scope for a TNSP to offer a large load directly connected to the transmission network a prudent discount (on the non-locational component of shared costs), in recognition of the credible risk of by-pass.

5.1.4 Summary and implications

Despite the adoption of limited CRNP, which is applied to load, the AEMC elected not to impose GTUOS. While this continued the *status quo*, any change would inevitably result in adjustment costs that would offset any potential efficiency benefits, the AEMC did not identify any such benefits. Rather, its analysis pointed towards their being costs.

They identified the potential inefficiencies of translating fixed charges levied on generators into efficient charges to load trough the mechanisms of the NEM. To the extent that such inefficiencies arise, they would likely weaken incentive for load to reduce consumption at peak times and for generators to maximise their connection capacity.[22]

As a practical matter, there would not appear to be a significant administrative cost associated with imposing GTUOS and reducing TUOS to load. Identifying such a change as a 'profound shift' is then a reflection then of these economic rather than administrative consequences.

5.2 Transmission pricing in other jurisdictions

5.2.1 National Grid in the UK

National Grid in the UK has operated incremental cost reflective pricing ('ICPR') since 1993/94.[23] In essence, the approach uses a DC load flow model to determine the transmission network consequences of inflows and outflows at different geographical zones within the network, and then determines the incremental capital costs of network augmentation to efficiently accommodate those power flows. An example of the resultant GTUOS is shown in Figure 4.

Figure 4. Generator TUOS (per kW) in England and Wales in 2011[24]

Zone	Area	Price £/kW	Zone	Area	Price £/kW
1	North Scotland	21.493	11	Anglesey	6.426
2	Peterhead	19.771	12	Dinorwig	5.720
3	Western Highland & Skye	22.933	13	South Yorks & North Wales	3.909
4	Central Highlands	18.181	14	Midlands	1.722
5	Argyll	14.047	15	South Wales & Gloucester	0.692
6	Stirlingshire	14.233	16	Central London	-6.846
7	South Scotland	12.563	17	South East	0.669
8	Auchencrosh	12.282	18	Oxon & South Coast	-1.882
9	Humber & Lancashire	5.581	19	Wessex	-3.668
10	North East England	8.861	20	Peninsula	-7.043

22 Assuming, as is generally the case, that TUOS charges are based on peak consumption or rated interconnection capacity.

23 See National Grid, April 2010, *Statement of Use of System Charging Methodology* available at http://www.nationalgrid.com/uk/Electricity/Charges/chargingstatementsapproval/ last viewed 23 January 2012.

24 Table 1.5 Wider Zonal Generation TNUoS tariffs applicable from 1st April 2011 taken from National Grid, April 2011, *The Statement of Use of System Charges* available at http://www.nationalgrid.com/uk/Electricity/Charges/chargingstatementsapproval/ last viewed 23 January 2012.

The approach adopted by National Grid also includes a somewhat arbitrary (at least in the economic sense) allocation of costs to load and generation of 73%, 27% respectively. National Grid is not the only market that operates this type of cost reflective pricing. CRNP applies to load in the NEM, at least in respect of a proportion of the share network costs incorporated into TUOS.

5.2.2 Other examples of locational GTUOS

Several South American markets, such as Columbia, used load flow based 'zones of influence' to set TUOS charges. These 'zones of influence' are determined on the basis of load flows. They include Argentina, Chile, Norway, Sweden, South Korea.

The nature of these charging frameworks is that, while aggregate GTUOS might recover between 20% and 30% of shared network costs, a significant proportion of the total paid by generation is likely to fall across those generators (possibly just a small proportion of the total) that are located in congested areas of the transmission network.

5.2.3 US market models

Most US market require that load pays 100% of shared network cost with no charge levied on generators. This applies in PJM, New York, California, New England and Texas. Generators are generally only charged shallow connection charges.[25]

However, a number of markets including PJM, New York, New England impose specific generator interconnection charges to cover the costs of deep augmentation to the network necessary to ensure network reliability standards are preserved. The charges are separated from TUOS. These deep augmentations do not necessarily ensure least cost system operation or allow incumbent generators to retain their prior level of network access. They therefore present a limited form of locational pricing. It has been suggested that these charges for deep augmentation give new entrant generators incentive to alter their time of entry in order to avoid the additional interconnection charges.[26]

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[25] California makes an exception for connection charges for wind generation. In ERCOT (Texas), connection charges for wind generation were highly contentious due to the remote locations of wind generation and its interruptible pattern of generation.

[26] PJM, March 10 2010, *A Survey of Transmission Cost Allocation Issues, Methods and Practices* at 24.

5.2.4 European pricing models

European is equally divided. 13 European countries including Germany, Spain, the Netherlands and Belgium allocate all shared network costs to load. A similar number including the UK, Scandinavia and France allocate a proportion of shared network cost to generators (the proportion varies between 0.5% and 35%). Although some commentators have sought to differentiate the TUOS rules in Europe between mature and less mature, suggesting the former are more likely to adopt GTUOS, a more convincing explanation lies in an understanding of the circumstances of the markets and, in particular, whether locational pricing in TUOS to generators is likely in those circumstances to deliver efficiency gains.

6 TUOS charges that meet the Code objective

Based on the foregoing discussion of pricing principles, network economics and comparative experience, there is a compelling case for allocating all shared network costs to load in SWIS. This section first addresses the perverse incentives that arise from the current GTUOS arrangements, which mean that the transmission pricing arrangements are inconsistent with the objectives of the *Code* and then sets out other factors that suggest the alternative model, in which all TUOS charges are levied on load, is likely to be better.

In so doing, the submission does not address the question of whether alternatives to shallow connection charges should be considered. There are transmission pricing paradigms in which connection charges levied on new load and generation include the costs of all necessary augmentation needed to support that load or generation while maintaining prescribed reliability, security and efficiency of grid operation[27] standards.

6.1 Inconsistencies with the *Code* objectives

6.1.1 Sunk generation costs and responses to fixed cost

It is not simply that alternative approaches better meet the *Code* objective. Rather, imposition of an uncertain fixed cost on a prospective generator entrant, which fixed cost need not be allocated to the generator and which does not reflect the costs that the generator imposes on the transmission system, is likely to be allocatively (and dynamically) inefficient, and therefore contrary to the *Code.* An access regime prone to such allocative inefficiency should not be accepted, to the extent that there are alternative approaches which do not suffer the allocative and dynamic efficiency impediment and do not impose other offsetting inefficiencies.

Two basic premises need to be considered in order to establish that the current GTOUS arrangements are inconsistent with the *Code:*

- the fixed costs of shared network assets necessary to support transmission of a generators power to load are unavoidable, and must be recovered either by load or by generation or both; and

[27] These standards might include, for example, specified levels of voltage support and maximum allowed levels of transmission losses.

- the allocative efficiency benefits from pricing derive from the responses they engender in consumers who face them. In the current context, allocative efficiency consequences of GTUOS must be assessed by reference to how generators respond to them.

Any pricing approach that results in unnecessary distortions to production or consumption decisions will be inconsistent with the *Code* in so far as those objectives specify:

- efficient investment in operation of and use of the network, which is an efficiency criterion in itself; and
- for the promotion of competition in upstream and downstream markets, which aims to foster efficient outcomes through the process of competition.

GTUOS, as it is currently structured, has two features which result in outcomes inconsistent with the *Code* in so far as they do unnecessarily distort consumption and production decisions:

- they are a fixed cost related to the declared sent out capacity ('DSOC') of the generator; and
- they are levied on an annual basis, and may change over the course of time as the network changes.

This has the result that they are seen as a fixed cost, the full extent of which is uncertain.[28] Generation fixed costs are predominantly capacity related and, once made, are irreversible (i.e. sunk). As a result, they cannot adjust the level of their installed capacity in response to a future increase in GTUOS charges even if, prior to entry, knowledge of the higher charge would have resulted in a different investment choice. Hence, GTUOS imposes a risk on prospective generator investors to which they are individually unable to respond once the investment is made.

[28] That uncertainty is not obviously alleviated by the regulatory process. Synergies notes that there is considerable uncertainty over the extent to which GTUOS charges will increase over time. The IMO has adopted an entirely different and lower assumption over escalation of GTUOS charges in its proposed Maximum Reserve Capacity Price than Western Power is forecasting. The economic inefficiencies of such charges are exacerbated if different regulators (or quasi regulators in the case of the IMO) have dramatically different assumptions on how GTUOS will change over time and the extent to which generators can be expected to recover it.

The consequence of that risk is that either:

- entry will be delayed; or
- less capacity will be installed (or the same quantum will be installed, but at higher cost).

In effect, the connection decisions of generators to the transmission network are more elastic with respect to price than are the connection decisions of the majority of load. Allocation of common fixed costs to the former is therefore more likely to result in welfare losses than direct allocation to the latter.

These risks are further compounded by the process by which generators expect to recover their fixed costs from the market (i.e. through wholesale trading arrangements), in which fixed cost recovery is affected by many factors, not least the future behaviour of potential competitors.

GTOUS represents a risk to the generation investor. It will therefore differentially impact investors that have different risk preferences. Were the risks in question solely risks associated with sunk generation assets in a wholesale market, the differential impact in respect of risk preferences would not be problematic. Since this is not the case, GTUOS can be expected to distort competition in the generation market to some degree. This is contrary to the *Code* objective of promoting competition.

Further but of less significance, to the extent that a generator can change its DSOC from time to time, GTUOS may even give the generator a perverse incentive at times to reduce their DSOC below their installed capacity. Since generation capacity costs are sunk, the objectives of the *Code* are really only consistent with generators making all of their capacity available at peak times.

Absence of CRNP

Markets such as the UK and those that use 'zones of influence' also impose GTUOS, for which some of these same arguments apply. However, in those markets the behaviour that results from the charge has some positive efficiency benefits. Specifically, it tends to encourage generation (and load) to locate where the costs of providing transmission services is low, and discourage location at expensive points. These benefits might, in these systems, offset the allocative inefficiency consequences noted above, but only to the extent that the underlying network genuinely accommodates flexibility over locations (see section 6.2.2 below). GTUOS in SWIS is not determined on the same basis.

Even if GTUOS charges are levied that accurately reflect the transmission related costs of generating at a particular location, it is important to recognise how those charges impact generator behaviour both at the time of entry and subsequently. Because generation costs are sunk, there is no economic efficiency benefit and potentially an efficiency dis-benefit from continuing with locational costs. Accordingly, locational GTUOS is probably inferior to locational once off connection charges in promoting completion and fostering efficiency in these markets.

6.1.2 Consistency with demand side management objectives

The processes of competition, which the *Code* seeks to promote, and allocative efficiency principles, which the *Code* requires in respect of network investment and use, should in tandem result in least cost (over the short and long-term) provision of power to customers. Working backwards from the final customer, it is possible to identify some outcomes that these combined processes (competition and regulated transmission) should deliver. In particular, the costs of supply are driven to a significant degree by peak demand for power in so far as:

- transmission assets are dimensioned to meet the expected peak;
- the average costs of generation used to meet peak demand are higher than generation used to meet off-peak demand; and
- customer willingness to pay for power also increases at time of peak demand, so the economic harm from supply interruption is highest at that time.

Absent market imperfections (such as monopoly, high transaction costs etc.) competition in a market with these characteristics would set prices with the following incentive properties:

- generators would face incentives to maximise availability, output and declared capacity at peak times; and
- customers would face incentive to decrease consumption at peak times.

GTUOS is inconsistent with these objectives and therefore inconsistent with the outcomes that the competitive wholesale markets are designed to produce. Specifically:

- GTUOS provides incentives to limit rather than enhance generator availability and output at peak times;
- load does not face the full shared network cost consequences of their peak demand decisions because 20% of those costs are allocated to generators. As a

result, they face weaker incentives than are efficient to minimise their peak consumption; and

- to the extent that GTUOS is passed on to customers, the full allocative efficiency benefits are diminished because of the imperfection that arise transacting the GTUOS costs through the wholesale market.

Since transmission assets are dimensioned to meet peak demand (i.e. to ensure secure and reliable deliveries to load, but no necessarily to provide the same level of access reliability to generators), failure to allocate all TUOS charges to load results in less than ideal incentive for load to reduce its peak time consumption and its demand for transmission assets.

6.2 Other efficiency factors

The foregoing sets out how GTUOS is contrary to the objectives of the *Code* in that it results in outcomes that would not arise if investment and use of the transmission network were efficient and if competition operated effectively in upstream and downstream market. It is also necessary to review whether alternative arrangements for TUOS would meet the *Code* objective.

The difficulty with the *Code* objectives is that, while the notion of efficiency lends itself to a bright line assessment (e.g. minimum long-run costs), the notion of promotion of competition is inherently one of degree. In our view, the ERA should assess whether the degree of promotion of competition is sufficient by examining whether:

- there are identifiable inefficiencies that would arise from competition in upstream and downstream markets under the pricing in the access arrangement;
- changes to the access pricing would allow competitive processes to remove these inefficiencies; and
- there are other inefficiencies that would result from the change that would offset the gains.

6.2.1 The ERA is the predominant determinant of efficiency

There do not appear to be any efficiency benefits from GTUOS in respect of fostering either efficient locational decisions or efficient transmission investment or operation. Even if this were not the case, it should be noted that the ERA, as the regulator of the transmission network, provides a regulatory safeguard of transmission system efficiency.

Hence, regulators play an increasingly important role in ensuring that transmission and distribution networks operate efficiently, and that future investment is similarly efficient. Hence, for example, in the NEM TNSPs cannot augment their networks and include the costs in TOUS unless the investments satisfy the necessary economic efficiency criteria. This may be the case even if a generators attached to the network requires augmented transmission in order to generate to their preferred schedule.[29] The efficiency benefits of TUOS (if any) are therefore of less consequence.

6.2.2 Constraints on the location of new generation

Even if GTUOS charges can have some efficiency benefits in some markets, important pre-requisites must be in place for the efficiency benefits to accrue including locational cost signalling in the wholesale power market (e.g. nodal pricing), a network topology and distribution of load, connection points and primary fuel sources like the UK, all of which accommodate genuine choice.

That is, the circumstances of the transmission network and power market are important determinants of the optimal pricing framework. Hence, for example, in the UK the transmission network:

- is extensive and well meshed,
- contains a large number of legacy generation sites;
- comprises many relatively large load centres; and
- is associated with a similarly extensive gas pipeline transmission network, rail haulage network and port system.

As a consequence, there are a wider range of potential sites for new generation (within the constraints of planning and environmental constraints, which are common to many markets). In contrast, networks in Australia including SWIS, are much less meshed and are more constrained in choices over the location of new generation. In consequence, the new entry decisions by generators in the UK are likely to be more sensitive to GTUOS charges that accurately reflect the transmission efficiency benefits of locating in particular locations (in so far as the approach adopted in the UK does so).

[29] It is common at times under least cost operation for generators to be 'constrained off' (i.e. be denied access to transmission).

6.2.3 Guaranteed access and transmission planning criteria

Although the SWIS supports bilateral contracts between generators and load and seeks to operate the system and transmission network to allow their consummation, it remains the case that:

- the main drivers of transmission augmentation, while directed at economic efficiency and promotion of competition, will be to preserve the reliability and security of supply for load. This outcome is driven by the imposition of reliability criteria couched in terms of supply reliability to load, by the very high value of lost load imposed on load if there are unexpected interruptions and by the inevitable community reactions to supply unreliability;
- notwithstanding the support for bilateral contracts, bilateral contract counterparties do not have property rights to network paths. Hence, generators are not guaranteed to be able to supply the exact amount of power specified under their contract as and when it is demanded;
- generators, particularly market generators, are not guaranteed access to customers and can be constrained off (prevented from operating) due to network constraints. Indeed, it is a necessary requirement for system efficiency that this is the case, in order for more efficient generation sometimes to displace less efficient generation in the competitive wholesale market; and
- no such equivalent arises in respect of load — it would not be considered efficient to routinely disconnect load at one location in the network in order to meet demand at some other location absent some special contractual arrangement (such as interruptible load).

These basic principles are essentially efficient, in so far as the welfare losses experienced by unexpected interruption of power to load resulting from inadequate transmission is considerably higher than the welfare losses experienced by generators being constrained to operate below their preferred level due to inadequate transmission.[30] However, they also indicate that all or a vast majority of the fixed costs of shared transmission assets should ideally be allocated to load in a manner that incentivises reductions in demand, particularly at times when preservation of system

[30] In reaching this conclusion, it is important to distinguish outages that result from inadequate transmission from those that arise from inadequate supply of generation. In the former, the market clearing price would be markedly different (i.e. lower) if the transmission was available. In the latter, the market clearing price would equal the value of lost load, largely irrespective of the adequacy of transmission.

reliability will be less costly if demand is moderated (i.e. peak demand periods). As noted by the AEMC:[31]

> This is because the majority of transmission investment in the shared meshed network is undertaken to meet the reliability obligations imposed to satisfy the requirements of consumers rather than to meet the requirements of generators to evacuate power.

6.2.4 Consistency with other Australian TUOS frameworks

While it is not a major consideration, it is notable that other Australian power markets have eschewed GTUOS in favour of allocating all shared transmission costs to load. There are efficiency benefits from so doing, but even if there were no efficiency consequences from different allocations of TUOS, there is benefit from national uniformity from the perspective of regulatory precedent, efficiency of regulation perspective, and the adoption of common practices that will benefits prospective investors.

6.2.5 Transaction costs

There are two transaction cost elements to consider in the design of TUOS, namely the transaction costs associated with the primary measurement and charging. While GTUOS imposes a small additional set of transaction costs which could be avoided, these costs are trivial and are unlikely to be material relative to the efficiency consequences noted above.

The more important transaction costs arise in the translation of shared transmission costs allocated to generators into final prices load, given that they are then subject to all the risks and difficulties associated with the wholesale power market, and given that the asset specific risks associated with shared transmission assets are somewhat different from those of generation assets.

Simply put, allocation of shared transmission costs to generators results in significantly higher transaction costs for the remuneration of those transmission costs than would be the case if the charges were directly allocated to load.

[31] AEMC. 2006. *Rule Determination: National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No. 22.* 21 December. pp 21.

6.2.6 Consistency with distribution UOS pricing

Transmission and distribution networks are contiguous and serve the same underlying purpose, that of transmitting power from generation to load. In so far as it is appropriate to allocate shared transmission charges to generators (which, from an efficiency or *Code* objectives standpoint it is not), then a similar argument arises in respect of distribution costs. It is almost universal practice to allocate all distribution costs to load (excepting shallow connection costs).

6.2.7 The arbitrary nature of the allocation

The allocation of shared network costs between load and generators in all markets that allocate to both (assuming shallow connection charges) is essentially arbitrary, whereas the allocation of all shared transmission costs to load has, for the reasons noted above, a coherent and non-arbitrary foundation. Principled regulation should prefer non-arbitrary approaches to cost allocation where there is a benefit in terms of economic efficiency (or advancing the Code objective) from doing so.

7 Conclusion

NewGen asked Synergies Economic Consulting to prepare a submission for the ERA which sets out the shortcomings of Western Power's current arrangements for setting TUOS charges, in terms of its failure to meet the objectives of the *Electricity Network Access Code 2004* ('the *Code*').

Western Power's current pricing allocates all connection charges to the network user, comprising the costs of the user to the high voltage network. These connection assets are, by their nature, dedicated to a single network user. These are termed 'shallow connection charges'. The costs of all shared network assets are recovered through recurrent TUOS charges, 20% of which are allocated to generation with the remainder allocated to load. This allocation of 20% to generators in the form of GTUOS is inconsistent with the objectives of the *Code*.

Section 2.1 of the *Code* states that *Code* should promote the economically efficient investment in; and operation of and use of network in order to promote competition in markets upstream and downstream of the networks. The GTUOS arrangement is inconsistent with the *Code* in that:

- it imposes a risk on prospective generator investors to which they are individually unable to respond once the investment is made. The consequence of that risk is that either that entry will be delayed or less capacity will be installed than would otherwise be the case. This is, in effect, an impediment to competition in the generation market;
- it presents weaker incentive for load to reduce peak demand and for generators to increase peak output that would otherwise be the case, thereby reducing the efficiency of investment in, operation of and use of network;
- there are no offsetting efficiency benefits arising from the GTUOS, such as improved decision making over location, lower transaction cost or guaranteed access to network services for generators, that offset these outcomes; and
- the regulation of transmission in Australia reduces the importance of TOUS as a signal of future efficient TNSP investment.

Western Power's GTUOS is inconsistent with practice elsewhere in Australia. Furthermore, Australian markets lack the pre-requisites that would make certain forms of GTUOS efficiency and competition enhancing, and it would be prohibitively disruptive to establish these pre-requisites.