A Review of the Benefits of Regulated Network Services

by

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1.0 Introduction

The Australian National Electricity Market (NEM) commenced operation in December 1998. It is generally agreed that the NEM has been a success, with significant benefits having been delivered (by the NEM) since its implementation. However there are still key outstanding issues which need to be resolved, one of which is the preferred framework for network services.

The Australian National Electricity Code (the Code) defines two frameworks for network services viz market and regulated network services. Whereas market network services are developed in response to competitive market price signals, the development of regulated network services is a centrally planned process controlled through the Regulatory Test.

The Regulatory Test is a 'theoretical' cost benefit calculation applied before a proposed network service is constructed, based on the best available data and assumptions and employing state of the art modeling techniques.

This paper first looks at the Regulatory Test as it presently stands, and performs a due diligence to compare the promised benefits with the benefits actually delivered. Confirmation of the delivery of the promised benefits gives some level of comfort that the theoretical calculation is robust. On the other hand confirmation that the promised benefits are not being delivered highlights issues with the theoretical calculation, and may point to required improvements i.e. what should be done differently to ensure a more robust calculation?

Amendments to the Regulatory Test are presently under consideration, with a key issue being the inclusion of so called 'competition' benefits.

The Regulatory Test is not a stand alone instrument. Rather, it is required to be consistent with the Code, which in part emphasizes the efficient operation, provision and expansion of network service facilities. Most parties therefore support the inclusion of competition benefits associated with increased economic efficiency, but not with wealth transfers.

The on-going debate regarding competition benefits has led to claims that the competition benefits delivered by regulated network services are substantial, and that therefore competition benefits should not be ignored. The second part of this paper undertakes a review of the validity of these claims. The key issue is that determining competition benefits is often quite complex, and if competition benefits cannot be quantified for claims related to specific historic market events, how can they be accurately quantified in a theoretical calculation which purports to forecast the electricity market over an extended (often up to 40 year) period?

Section 2 of this paper briefly outlines the regulated network service framework. Section 3 then reviews the Regulatory Test, with particular emphasis on the benefits. Section 4 details the benefits arising from the application of the Regulatory Test to specific inter-regional regulated network services (i.e. interconnections between regions), while Section 5 focuses on what was actually delivered. Section 6 then highlights the complexities associated with validating competition benefits.

2.0 Commercial Frameworks for Network Services

The Australian National Electricity Code (the Code) defines two commercial frameworks for the development of network services: 'market' and 'regulated' network services.

The focus of this paper is regulated network services[1].

2.1 The Regulated Network Service Framework

The providers of a regulated network service receive a regulated revenue stream for their investment over the (up to 40 year) life of the underlying asset. The regulated revenue is collected from all consumers through mandatory use of system charges (both transmission and distribution). The use of system charges do not appear in the competitive market prices, which in Australia are currently 'generation service only' prices. The regulated network service provider determines the use of system charge for its network so as to recover the revenue allowed of it by the regulator.

The ACCC (as the transmission regulator) recognized the importance of ensuring that regulated network services deliver net benefits, and controls their development through the application of the Regulatory Test[2].

Before a proposed investment to provide a regulated network service can proceed, the Code requires theoretical calculation under the Regulatory Test of the net market benefits associated with the proposed investment. The project proponent estimates the net market benefits of a new regulated network service with and without the proposed service. The theoretical calculation necessarily involves forecasts of future generation costs with and without the project, which in turn requires forecasts of fuel prices, demand growth, reliability requirements, future generation investments, and trends in generation technology. A net market benefit may also be calculated for generation and demand side options that could replace the proposed investment. If the proposed network service

[1] Further information on the two frameworks can be obtained from the paper by A. Cook and R. Coxe, *A Review of Commercial Frameworks for Network Investments in Competitive Power Markets*, available at www.transenergie.com.au

[2] ACCC, *Regulatory Test for New Interconnectors and Network Augmentations,* 15 December 1999 (***Regulatory Test***)

maximises the net market benefits it is deemed to be 'justified' under the terms of the Code, and is awarded regulated status.

The initial estimate of the Regulatory Test benefits associated with a new regulated network service is dependent on parameters which are themselves highly uncertain.

The regulated network service framework relies on regulatory review processes to insure that network investments continue to deliver net benefits over the life of the asset.

3.0 The Benefits Delivered by Regulated Network Services

The Regulatory Test defines the permitted benefits of regulated network services. The ACCC has developed the Regulatory Test to be '*largely consistent with the standard principles used in economic cost benefit studies*[3]', which principles '*seek to maximise the sum of consumer and producer surplus based on estimates of efficient economic costs and benefits*[4]*'*. Consistent with the economic efficiency objective associated with the Regulatory Test:

- regulated network services should deliver a net benefit to consumers, and
- consumers should not incur unnecessary costs.

The Regulatory Test is applied before a proposed network service is constructed, based on the best available data and assumptions. It is therefore of particular importance to perform an 'after the fact' review to confirm that the benefits which were promised are being delivered. If the promised benefits are not being delivered, then the review may highlight modifications to the theoretical calculation which make the application of the Regulatory Test more robust.

This section reviews the benefits attributed to regulated network services under the Regulatory Test.

3.1 Regulatory Test Benefits

The Regulatory Test is broadly structured into three parts viz explanatory notes, the statement of the Regulatory Test itself, and notes on the methodology to be used in applying the Regulatory Test. It is the notes on the methodology that provide general guidance on the permitted benefits. In particular, note 1 states in part:

> '*In determining the market benefit, the following information should be considered:*
> *(a)* …………….
> *(b)* *reasonable forecasts of:*
>
> *i.* ……….

[3] Regulatory Test, page 4
[4] Regulatory Test, page 4

ii. *the value of energy to electricity consumers as reflected in the level of VoLL;*

iii. *the efficient operating costs of competitively supplying energy to meet forecast demand from existing, committed, anticipated and modelled projects including demand side and generation projects;*

iv. *the capital costs of committed, anticipated and modelled projects including demand side and generation projects and whether the capital costs are completely or partially avoided or deferred;*

v. *the cost of providing sufficient ancillary services to meet the forecast demand; and*

vi. *…………..*[5] ’

The permitted benefits can therefore be generally classified as follows:

- Energy benefits
  Energy benefits arise when network services permit less expensive generation in one region to displace more expensive generation in another region. In that case a network service reduces the short run variable operating and maintenance costs, and fuel costs in the NEM.

  Reductions in spot market energy prices (including reductions in spot market energy price volatility) that are wealth transfers between market participants are not presently counted as an energy benefit. However, they have been suggested as a permitted benefit under proposed amendments to the Regulatory Test.

- Reliability benefits
  A proposed network service can reduce the likelihood of load shedding, and thus the level of unserved energy. Valuing the reduction in unserved energy at VoLL[6] quantifies the reliability benefits.

- Deferred generation benefits
  Deferred generation benefits arise when a new network service supply option defers the need for new generation investment.

- Deferred network benefits
  Under certain circumstances a deferred network benefit may arise from the deferral of the need for another proposed network service.

- Ancillary service benefits
  Reductions in the costs of providing ancillary services may be delivered through the competitive provision of those services. Cost reductions which are simply wealth

[5] Regulatory Test, page 22
[6] Value of Lost Load, presently set at $10,000/MWhr

transfers are not permitted benefits, however they have been suggested as a permitted benefit under proposed amendments to the Regulatory Test.

4.0 The Application of the Regulatory Test

Table 1 details the results of the application of the Regulatory Test to different inter-regional regulated network services. It should be noted that the Regulatory Test was not actually finalised by the ACCC until December 1999, and therefore both the Riverlink and QNI projects were not strictly assessed under the Regulatory Test. However, the approach employed in the assessment of each of these projects was sufficiently consistent with that set down in the Regulatory Test for them to be included in this review.

Benefit ($M)	Riverlink[7]	QNI[8]	SNI[9]	SNOVIC 400[10]	Murraylink[11]
Energy	4	56	25	1	82
Reliability	-	-	-	-	62
Deferred Generation	164	571	154	262	54
Deferred Network	15	35	18	-	24
TOTAL	183	662	197	263	222

Table 1 Results of the Application of the Regulatory Test

Table 1 highlights that the Murraylink project is the only project with an explicit reliability benefit. This is because the calculation methodology for the Murraylink project is different to that for the other projects:

> '*In its evaluation of SNI and SNOVIC 400, the IRPC explicitly considered the reserve levels established by the Reliability Panel for each region of the NEM, and then compared the expected market generation with these required reserve levels. Where there was a shortfall, reliability generation was then added to the market development scenario, such that the reserve criterion was met. The reliability benefit associated with each alternative project in the SNI and SNOVIC 400 analyses was then calculated on the basis of the extent to which each alternative defers the need for this reliability generation. As such, the calculation*

[7] Unknown Author, *Report on Technical Issues, Costs and Benefits Associated with the Riverlink Interconnection – Between the Electricity Networks of South Australia and New South Wales, Schedule 2*, undated (**Riverlink Paper**)

[8] London Economics, *Independent review of the economic costs and benefits of interconnection of the Queensland and New South Wales electricity grids*, August 1997, page v (**QNI Paper 1**)

[9] Roam Consulting Pty Ltd, *Economic Evaluation of the Proposed SNI Interconnector*, October 2001, Results for Simulation 1-S-M, SNI Project

[10] Roam Consulting Pty Ltd, *Economic Evaluation of the Proposed SNI Interconnector*, October 2001, Results for Simulation 1-S-M, SNOVIC Project

[11] ACCC, *Murraylink Transmission Company Application for Conversion and Maximum Allowed Revenue, Decision,* 1 October 2003, page 75

> *of the reliability benefit was conducted on a similar basis to the calculation of the benefit from the deferral of market generation.*
>
> *The approach by MTC to calculate the reliability benefit is very different to that used by the IRPC in its evaluation of SNI and SNOVIC 400. MTC has calculated the reliability benefit by assessing how much market-driven generation is expected under both the 'with Murraylink' and 'without Murraylink' scenario, and then calculating the extent of the unserved energy which remains (using a probabilistic modeling tool) and valuing this unserved energy at VoLL (ie, $10,000/MWhr)*[12]*.*'

TransGrid goes on to argue that not all of the unserved energy valuation should be included as a benefit:

> '*It is only where the differences in reliability are **above the reserve level** that the form of unserved energy (USE) valuation used by TEUS becomes appropriate. The IRPC analysis noted that the reduction in USE over and above the required level was a benefit to the market options.* '

This matter is also discussed elsewhere[13]. As best can be determined from that discussion, the Murraylink calculation can be made more directly comparable to that for the other projects by allocating the bulk of the 'Reliability' benefit to the 'Deferred Generation' category.

Table 1 highlights that energy benefits typically constitute less than 13% of the purported total benefits of regulated network services. Murraylink is the exception. It has already been noted that the Murraylink calculation methodology is different to that adopted for the other projects, and it is presumed that the anomalous Murraylink energy benefit can also be attributed to those differences.

It should be noted that a proposed network service does not always deliver a deferred network benefit. Whether a deferred network benefit is delivered is determined by the connection point for the proposed network service, and the topology and loading levels of the existing network.

5.0 Benefit Due Diligence Studies

Table 1 highlights that deferred generation benefits constitute the bulk of the promised Regulatory Test benefits. It is therefore reasonable that any comparison of the promised and delivered benefits should focus on the deferred generation benefits.

[12] TransGrid, *Murraylink Transmission Company, Application for Conversion of Murraylink to Prescribed Services*, Submission to the ACCC, March 2003

[13] For example:

- NERA, *Comments on Murraylink's Application for Conversion to Regulated Status*, A Report for TransGrid, January 2003, and
- Murraylink Transmission Company Pty Ltd, Letter to the ACCC dated 8 April 2003, Appendix 3 of the attached report.

Deferred generation benefits arise when a new network service defers the need for new generation investment. The key issue is therefore whether a new regulated network service has deferred the construction of new generation.

This section considers in detail the promised deferred generation benefits for the Riverlink and QNI projects, and makes general observations on the promised deferred generation benefits of the SNI and SNOVIC 400 projects.

5.1 Riverlink Case Study

Riverlink was proposed as an interconnection between the New South Wales and South Australian networks.

Table 1 highlights that 89% of Riverlink's promised benefits are deferred generation benefits.

The $164 M deferred generation benefit is made up of two components viz $157 M associated with the deferral of new generation capacity, with the remainder purportedly arising from economies of scale associated with generation units of greater than 250 MW capacity. The $157 M is made up as follows:

- in South Australia (SA), a $140 M deferred generation benefit to be delivered 1-2 years after commissioning, and
- in New South Wales, a $17.5 M deferred generation benefit to be delivered 5 – 10 years after commissioning.

The focus of this discussion is the SA deferred generation benefit.

5.1.1 SA Deferred Generation Benefit

Table 2 provides the new South Australian supply side capacity estimated to be required to achieve acceptable levels of supply reliability. Riverlink's nominal capacity was 250 MW, and it was assumed to be commissioned for Summer 1999/2000 to meet the requirements of the years 1999/00 and 2000/01. To date, Riverlink has not actually been constructed.

Year	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05
Capacity (MW)	200	50	100	50	50	50

Table 2 Additional SA Supply Side Capacity Estimated to be Required to Achieve Reliable Supply[14]

Key assumptions in the analysis were:

- The 240 MW Playford B Power Station had been retired due to environmental and cost reasons; and

[14] Riverlink Paper, Table 4

- '*No allowance has been made for the possible future generation installations that are being assessed by private developers as these are considered speculative at this stage*[15].'

Regarding the first assumption, Playford Power Station has not been retired. Rather, the state government sold it to NRG Flinders, who was successful in obtaining an extension of its environmental licence, and is now spending millions of dollars refurbishing it. NEMMCO's 2003 Statement of Opportunities confirms that the 240 MW Playford Power Station is expected to be in service until at least 2012.

The assumption regarding Playford Power Station was therefore incorrect, even though at the time it appeared relatively certain and was based on the best available information.

The validity of the second assumption is more difficult to assess because it could easily be argued that private developers would have had a lesser incentive to develop new supply side options had Riverlink proceeded. However, conclusions can still be drawn regarding this assumption.

The South Australian Summer 1999/2000 supply side capacity is detailed in Table 3. The 10% probability of exceedence medium growth demand was 2,650 MW, giving a reserve plant margin of only 12.5%. Such a low reserve plant margin confirms the need for new supply capacity at that time. The need for new South Australian supply side capacity was also highlighted to private developers through a high SA spot market price signal.

Supply Side Capacity	Capacity (MW)
Optima Energy	1,280
Flinders Energy	905
Synergen	295
Heywood Interconnection	500
TOTAL	2,980

Table 3 SA Summer 1999/2000 Supply Side Capacity[16]

Table 4 details that 1,069 MW of new South Australian supply side capacity has been developed in the period 1999 to 2003. In the same period the 10% probability of exceedence medium growth demand has increased by only 400 MW. The reserve margin is therefore now 32.8%, an excessive margin for an interconnected system[17].

[15] Riverlink Paper, Section 4.1

[16] L. Gill, *TXU's Perspective on Supply, Pricing and Competition in South Australia*, SA Power Conference, 29 April 2003, Slide 4

[17] It might be argued that had Riverlink proceeded at least some of the Table 4 supply side options would not have proceeded. Pelican Point Power Station is probably the most controversial of the new supply side options. It is understood that approximately 250 MW was contracted to the SA government when Riverlink failed to obtain regulatory approval. However, on the other hand it should be noted that the developer decided that the additional 237 MW was commercially viable. One could also postulate that the Murraylink market network service would also have been unlikely to proceed.

On the basis of the excessive plant margin that now exists it appears that a number of different private developers have not been deterred from developing new supply side capacity simply because other supply side options were proceeding. Therefore there is a strong basis for concluding that the assumption to ignore '*possible future generation installations that are being assessed by private developers*' was also invalid.

Supply Side Option	Capacity (MW)
Ladbroke Grove	69
Pelican Point	487
Quarantine	90
Hallett	153
Murraylink	220
Torrens Island upgrade	50
TOTAL	1,069

Table 4 New SA Supply Side Options 1999 to 2003

The conclusion is therefore that had Riverlink proceeded, it would not have deferred the generation capacity set down in Table 2, simply because Playford B was not retired, and new capacity is likely to have been developed with or without it.

This is a significant conclusion because with an estimated cost of $107 M, Riverlink was projected to deliver total benefits of $183 M[18]. Disallowance of the complete $140 M deferred generation benefit gives Riverlink a net benefit of -$64 M i.e. a net cost.

5.2 QNI Case Study

QNI was proposed as an interconnection between the Queensland and New South Wales electricity networks, and was planned to be in service in late 2001[19].

As with Riverlink, Table 1 highlights that the bulk (i.e. 86%) of QNI's promised benefits are deferred generation benefits.

The QNI proponents quantified the deferred generation benefit as:

> '*750 MW of avoided generating plant which would be required to maintain a reasonable level of system security (measured by LOLP) in Queensland and New South Wales in the absence of the interconnection*[20].'

London Economics confirmed this position when it stated:

> '*..a total saving of at least 700 MW could result from the construction of a 500 MW interconnect between NSW and Queensland, 400 MW of which would be located in Queensland and 300 in New South Wales*[21].'

[18] Riverlink Paper, Schedule 1
[19] QNI Paper 1, page 12
[20] QNI Paper 1, page 13

The approximate timing of the deferred generation benefit was given by the fact that:

> *'Queensland would require new capacity in the year 2001/02 in the absence of the interconnect. New South Wales would require new capacity by the year 2006/07 in the absence of the interconnect[22].'*

The $571 M deferred generation benefit was split $350 M to Queensland[23] and the remainder to New South Wales.

London Economics highlighted that:

> '*Benefits from avoided generating capacity arise because new plant can be delayed in both Queensland and New South Wales[24].'*

Therefore the key to confirming the validity of the generation deferral benefit is to confirm the delay of 400 MW in Queensland around 2001/02, and the delay of 300 MW in New South Wales around 2006/07.

Table 5 shows that 2498 MW of new Queensland generation capacity has been commissioned in the period 2001 to 2003. It is interesting to note that the first unit of Callide C commenced commissioning in early 2001 almost co-incident with the commencement of QNI commissioning, and that the second Callide C unit commenced commissioning in July 2001. On that basis it appears difficult to argue that QNI deferred any Queensland generation at all, in which case the bulk of Queensland's $350 M deferred generation benefit appears to be invalid.

Supply Side Option	Capacity (MW)
Callide C	840
Millmerran	853
Tarong North	450
Swanbank E	355
TOTAL	2,498

<u>Table 5</u> New Queensland Supply Side Options 2001 to 2003

That QNI did not defer the commissioning of any Queensland generation plant is also confirmed by the QNI flow duration curve for the first six months of 2001, as per Figure 1. This figure highlights that QNI power flow was from Queensland to NSW for approximately 65% of the time. This statistic is more consistent with Queensland having an excess of generation capacity, and is not at all consistent with a position that QNI deferred new Queensland generation capacity, in which case it would have been expected

[21] QNI Paper 1, page 19
[22] QNI Paper 1, page 13
[23] QNI Paper 1, pages 17 and 18
[24] QNI Paper 1, page 25

that New South Wales would have been required to provide power flow support to Queensland, rather than the reverse occurring.

The NSW deferred generation benefit was not due to be realized until around 2006/07, and therefore that benefit will not be examined.

At this stage the conclusion is that QNI has not delivered its promised Queensland deferred generation benefit.

This is a significant conclusion because QNI was projected to deliver a net present value (NPV) benefit of $135 M[25]. Disallowance of only the Queensland benefit gives QNI a NPV net benefit of -$215 M i.e. a net cost.

It has been stated that QNI '*capital cost was about $350 M, which was $60 M below the independent estimate*[26]'. On that basis the independent estimate was $410 M, which is greater than the August 1997 capital cost estimate of $382 M. Irrespective, this does not change that QNI was apparently constructed at a net cost.

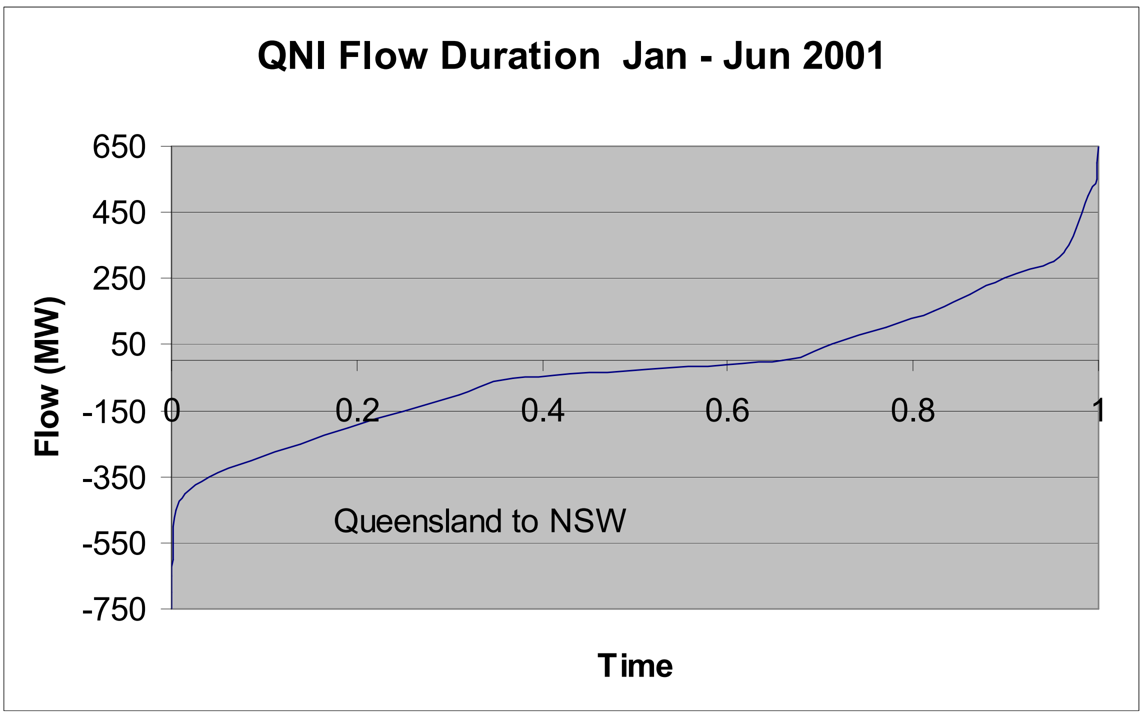

Figure 1 QNI Flow Duration

[25] QNI Paper 1 page v
[26] G. Jardine, *QNI: Benefits vs Costs*, Interconnect 2001 Conference (**QNI Presentation**), Slide 14

5.3 SNI Case Study

SNI has been proposed as an interconnection between the New South Wales and South Australian networks.

SNI is a variation of Riverlink and it is therefore not surprising to note that like Riverlink, the bulk of SNI's promised benefits (78%) are deferred generation benefits. Difficulties with the delivery of this category of benefits have already been highlighted for both the Riverlink and QNI network services. In particular, deferred generation benefits which have been forecast to occur either immediately or within 1 – 2 years of commissioning do not appear to have been delivered.

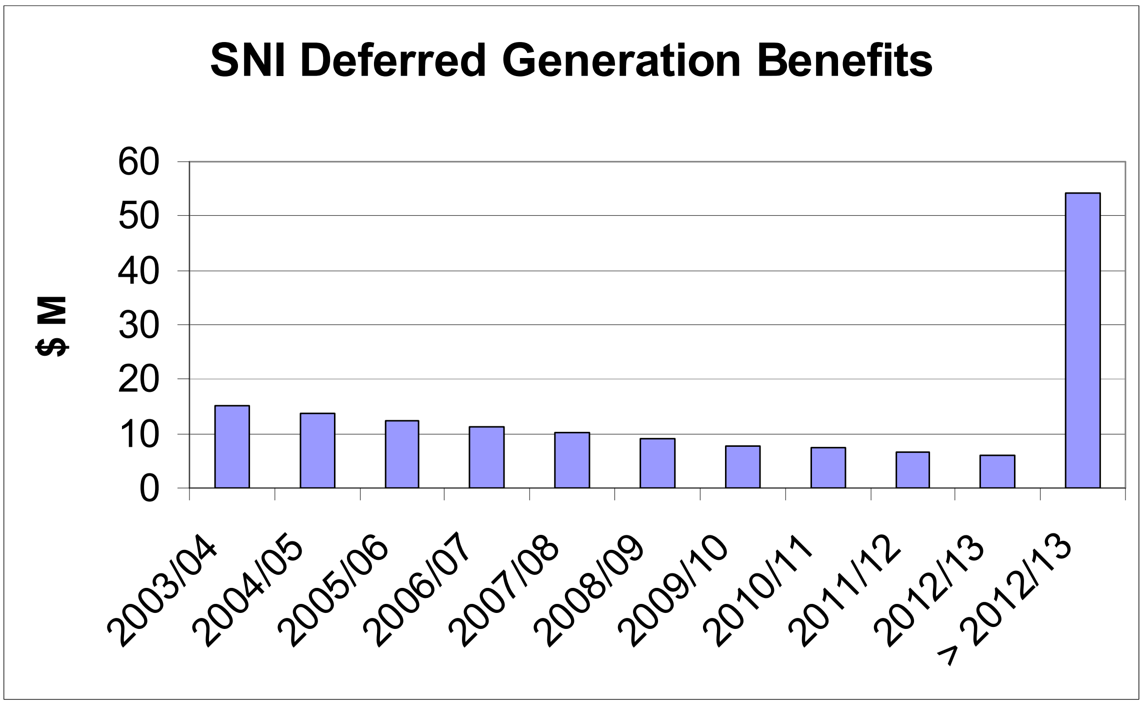

Figure 2 Timing of SNI Deferred Generation Benefit

Figure 2 details the timing of the $154 M SNI deferred generation benefit. Note that $125 M of the total benefit occurs in years 3 or later. Given the difficulties already discussed in obtaining benefits even 1 – 2 years into the future, there must be very real doubts that any of these $125 M in benefits will ever be delivered.

This conclusion seriously calls into question that SNI would have delivered its theoretical deferred generation benefit.

Figure 3 highlights similar issues with the SNOVIC 400 deferred generation benefit.

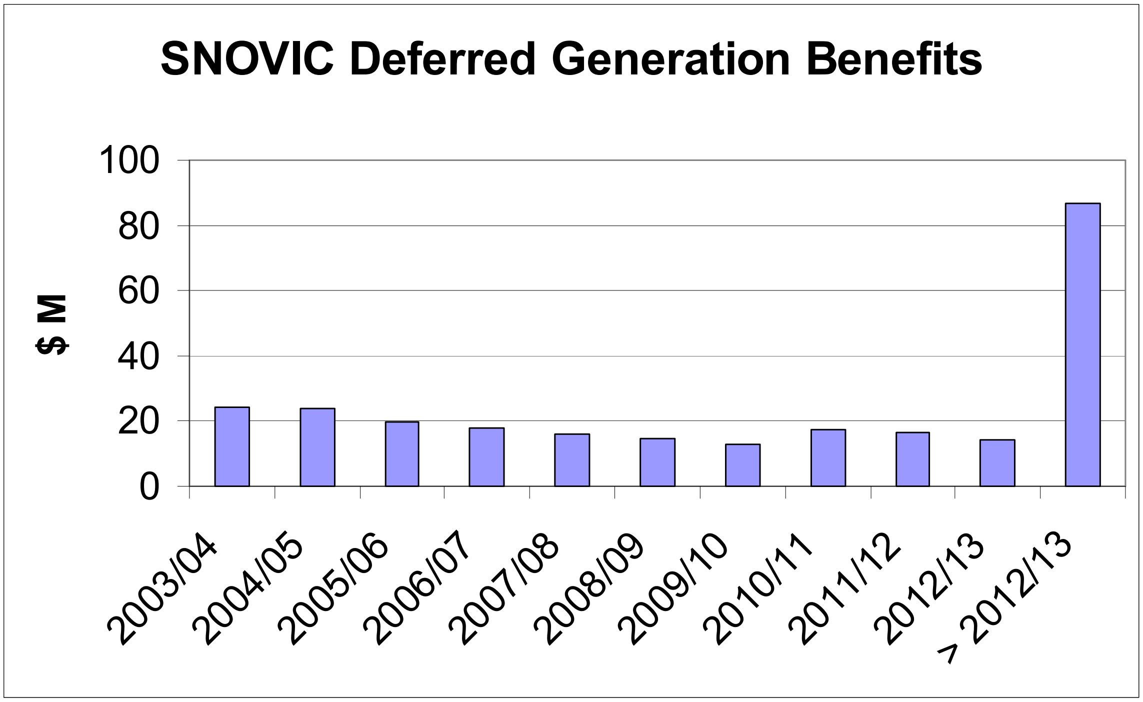

Figure 3 Timing of SNOVIC 400 Deferred Generation Benefits

5.4 Discussion

This section has examined the delivery of the (substantial) deferred generation benefit promised by regulated network services. The analysis performed has concluded that regulated network services do not deliver on that promise. This should not be a surprising outcome, particularly given that the methodology for estimating the promised benefits ignores the dynamics of the competitive market. We consider the pre and post NEM time periods.

Historically, each Australian State had vertically integrated utilities that were responsible for all aspects of the industry i.e. the vertically integrated utility controlled the generation of electricity, the transmission of electricity and the delivery of electricity to consumers. It was only as a part of the broader national competition policy reforms which led to the introduction of the NEM that the vertically integrated utilities were split up into separate companies that focused on a specific area of the industry i.e. generation or transmission or the delivery of electricity to consumers.

Therefore historically the vertically integrated utility controlled investment in both new generation and new network services. Typically, as a part of the least cost planning approach to ensuring a reliable and secure power supply, the vertically integrated utility traded off the value of investments in generation against the value of investments in network services. In that environment, where the utility controlled investment in both generation and network services, deferred generation benefits were likely to be delivered because it was nonsensical for the utility to duplicate a network service investment with a generation investment.

In a competitive market (such as the NEM) decisions regarding investment in new regulated network services are made by a different party to that making decisions regarding investment in new generation facilities. (In fact in a competitive market decisions regarding investment in new generation facilities are made by multiple competing parties.) Therefore within a competitive market framework it is impossible for the developer of new regulated network services to prevent their duplication by new generation facilities[27], and deferred generation benefits are unlikely to be delivered.

The conclusion that deferred generation benefits are unlikely to be delivered does not mean that their inclusion as a benefit under the Regulatory Test is invalid. Rather, it highlights that the calculation of deferred generation benefits needs to be modified to take competitive market dynamics into account. This could be as simple as including a discount factor in the deferred generation benefit calculation, with the magnitude of the discount factor increasing the further into the future are the promised deferred generation benefits.

6.0 Competition Benefits

The Regulatory Test has been criticised by some because it does not recognise competition benefits. However, further investigation by the ACCC has highlighted that the issue is not simple because the individual critics themselves have different definitions of what constitutes competition benefits. For example, some parties '*support a definition of competition benefits which is limited to benefits from increases in market efficiencies*[28]'. Others support a broader definition that '*considers the benefits of lower prices to electricity consumers*[29]' yet presumably ignores the dis-benefit of lower prices to producers. Still others have raised policy issues; for example, whether it is appropriate for the proponents of regulated network services to determine '*whether market power exists and propose measures to alleviate the costs arising from market power*[30]'.

Assuming that these different opinions on the definition of competition benefits can be satisfactorily resolved, there is a need to agree on a robust competition benefit calculation methodology. Unfortunately this is likely to be more difficult than is generally realized, particularly for the broader definition of competition benefits. For example, the broader definition could require the forecasting of the future bidding behavior of generators over some specified period of time, as well as customers' responses to the market price outcomes. These variables are highly subjective, and the requirement for such forecasting could leave the Regulatory Test open to dispute and delay. These difficulties may in fact require that the definition of competition benefits is narrower rather than broader.

[27] This author would argue that in a competitive market new regulated services are not an equally valid alternative to competitive market investments, and that it is the regulated network service that is unnecessarily duplicating new generation facilities.
[28] ACCC, Review of the Regulatory Test for network augmentations, Draft Decision, March 2004, page 43
[29] Ibid
[30] Ibid

The objective of this section is not to propose a definition of competition benefits, nor to propose a calculation methodology to estimate competition benefits. Rather, the objective is to consider some of the specific claims regarding the level of competition benefits associated with the broader definition, and to demonstrate that the calculation is considerably more complex and more difficult than its proponents realize, to the extent that the claimed competition benefits are not robust.

This section first considers claims regarding energy benefits (i.e. spot market price reductions and lower spot market price volatility) and then ancillary service benefits.

6.1 Energy Benefits

Table 1 highlighted that the energy benefits associated with increases in market efficiency are typically relatively small. In contrast the proponents of a broader definition of competition benefits have claimed considerable energy benefits.

At the outset it must be noted that lower energy prices are not themselves even confirmation of any energy benefits at all. This is because NEM consumers have the choice of purchasing their energy requirements through either contracts or the spot market. If the bulk of consumers have chosen to enter into contracts there is an incentive for suppliers to bid down the spot market price in order to minimize their contractual risks. In that case there may well be an inverse relationship between the spot market price and the price that consumers are paying; that is, consumers could have entered into high priced contracts which in turn forced down the spot market price. In that case a reduction in the spot market price may be an indicator of no energy benefits at all. As other parties have noted, a focus on lower spot market prices '*is dangerous and generally misleading*' and '*lazy commentators refer to it alone and draw unjustified conclusions*[31]'.

6.1.1 Lower Spot Market Prices

This section first considers general claims regarding the energy benefits of regulated network services under the broader definition of competition benefits. It then considers specific claims regarding the considerable energy benefits delivered by QNI.

6.1.1.1 Energy Benefits and Regulated Network Services

It has been claimed that regulated network services are the only supply side option able to reduce spot market energy prices.

For example, regarding the generation supply side option Bardak – Energy and Management Services (Bardak)[32] talks about '*exploitation by the limited number of generators possible in Australia as a whole and in the individual regions*[33]' and '*the opportunities for the Queensland generators to exploit their undoubted market power*[34]'.

[31] ESCOSA, Submission to the Select Committee on the Electricity Industry in South Australia, March 2004, page 9

[32] R. Booth, '*An Assessment of the first six months of operation of the QNI interconnection*', available at www.bardak.com.au. (**QNI Paper 2**)

[33] QNI Paper 2, page 1

[34] QNI Paper 2, page 6

Regarding the market network service supply side option it states that:

> '*The problems with Directlink, and other so-called "market network service providers", in contrast to normal regulated interconnectors…is that they must seek to maintain a certain price differential ….*[35]'

In fact any increase in the number of supply side options will lead to increased supply side competition, which in turn has the potential to deliver lower spot market energy prices. That is, lower energy prices are not a guaranteed outcome of a new supply side option. Rather, it can only be stated that new supply side options have the potential, but not the certainty, to deliver lower energy prices through increased competition.

Regulated network services are a supply side option, and therefore that regulated network services have the potential (but not the certainty) of delivering lower energy prices appears quite valid. However, the claim for delivering lower energy prices is by no means unique to regulated network services. Generation, demand side or market network service supply side options are also likely to lead to lower energy prices through the increased competition introduced by their very presence, irrespective of any commercial incentive that they might have to maintain higher prices.

A factor which gives weight to the claims is that the owners of regulated network services earn their revenue outside of the competitive market, and therefore have no interest in competitive market outcomes. However it is the level of contracts entered into by generators and market network services that determines their interest in competitive market outcomes. For example, generators and market network services with a high level of contracted capacity earn the bulk of their revenues outside the competitive market, and therefore (like regulated network services) have little immediate interest in competitive market outcomes. In contrast, highly uncontracted generators and market network services certainly have an immediate, contemporary interest in competitive market outcomes.

That regulated network services have the potential but not the certainty of delivering lower spot market energy prices is illustrated by the events of 23 June 2003, which are discussed in Section 6.1.1.1.1.

The claims regarding the delivery of lower spot market energy prices by regulated network services appears to rely heavily on an analysis of data associated with the commissioning of the QNI interconnection between Queensland and New South Wales. Section 6.1.1.1.2 reviews that analysis.

6.1.1.1.1 The Events of 23 June 2003

Any new supply option has the potential, but not the certainty, of delivering lower spot market energy prices. Whether lower spot market energy prices (and therefore benefits)

[35] QNI Paper 2, page 2

are in fact delivered depends on the dynamics of the competitive market, which may or may not be modified by the increased competition associated with a new supply option.

The events of 23 June 2003 highlight an instance when increased competition across the regulated QNI network service was not delivered, and QNI was therefore not successful in delivering lower spot market energy prices.

Table 6 presents NEM data for part of 23 June 2003. For the bulk of the day the Queensland spot market price was less than the NSW price, so QNI power flow was from Queensland into NSW (shown by a negative QNI Power Flow in Table 6). At 18:00 hours the NSW spot market price spiked (the cause of the spike is not known), and the Queensland spot market price followed suit. The spot market price remained high for approximately 2 hours, and then settled down at a lower level.

A review of the available NEM data regarding the incident has confirmed that:

- QNI was not constrained.
  For example, at 18:00 hours (the time of the highest price) QNI's flow into NSW was only 157 MW, considerably less than its 780 MW limit.

- Queensland had surplus generation capacity.
  The available Queensland generation capacity was approximately 8,300 MW, of which only 6,505 MW was required to meet Queensland demand.

- The Snowy interconnection was flowing 3,112 MW into NSW (close to its limit); and

- NSW had surplus generation capacity.
  The available NSW generation was approximately 10,500 MW. This generation was required to meet a residual demand of 8,403 MW (calculated as the actual NSW demand of 11,671 MW less that supplied from Snowy and Queensland).

	QLD Spot Price ($/MWhr)	NSW Spot Price ($/MWhr)	QNI Power Flow (MW)
23 June 2003 17:00	26.2	27.8	-298
23 June 2003 17:30	52.4	52	-67
23 June 2003 18:00	7741.6	7947.7	-157
23 June 2003 18:30	7573.8	7984.1	-274
23 June 2003 19:00	1547.3	1609.2	-226
23 June 2003 19:30	63.2	65	-174
23 June 2003 20:00	55.5	50	323
23 June 2003 20:30	66.0	60.1	278
23 June 2003 21:00	59.1	54.7	204
23 June 2003 21:30	45.3	44	16
23 June 2003 22:00	33	33.6	-158

Table 6 NEM Market Data for 23 June 2003

The conventional wisdom is that because QNI was not constrained it should have levelised prices in each of Queensland and New South Wales to around the Queensland spot market price at 17:30 hours of $52.4/MWhr (or even $26.2/MWhr at 17:00 hours). However, Table 6 shows that contrary to the conventional wisdom the Queensland generators modified their bidding patterns and actually followed the NSW bidding patterns. This had the effect of not reducing the NSW spot market prices.

This example highlights that rather than being guaranteed to deliver lower spot energy market prices, regulated network services are only guaranteed to deliver price uniformity across the NEM. This factor needs to be incorporated into any calculation of competition benefits.

It should be noted that not only did QNI not reduce NSW spot market prices. In addition, the price uniformity that QNI delivered forced Queensland consumers to pay excessive energy prices. If it is assumed that Queensland consumers should have paid only the spot market price at 17:00 hours for the 17:30 – 19:00 hour interval, then the additional payment incurred by Queensland consumers works out at $54 M, a not inconsiderable amount[36]!

6.1.1.1.2 QNI Energy Benefit

Powerlink Queensland (Powerlink) has claimed a QNI energy benefit considerably greater than that of Table 1. Powerlink describes three categories of benefits:

- a '*reduction in pool prices*',
- a '*reduction in pool price volatility*', and
- '*reductions in ancillary services costs*[37]'.

This section first considers the claim regarding a reduction in pool prices, and then the claim regarding a reduction in pool price volatility. The claim regarding a reduction in ancillary service costs is considered in Section 6.2.

6.1.1.1.2.1 QNI Energy Benefit from a Reduction in Spot Market Energy Prices

The benefit arising from a reduction in spot market energy prices has been calculated as $22.5 M per week[38]. Only partial details of the calculation are given, but it is assumed to proceed as follows:

1. The April – June quarter 2001 spot market price was $34/MWhr in both Queensland and NSW. The prices in the same quarter in the year 2000 were $59 and $46/MWhr respectively[39].
2. The Queensland energy consumption in the April – June quarter 2001 was 10.733 GWhrs[40].

[36] This statement assumes that Queensland consumers were purchasing all their energy from the spot market, rather than under contracts
[37] QNI Presentation, Slide 15
[38] QNI Presentation, Slide 20
[39] QNI Presentation, Slide 18

3. The quarterly benefit is then calculated as the product of the pool price reduction (i.e. $(59-34)/MWhr = $25/MWhr) and the Queensland energy consumption, and converted to a weekly benefit by dividing by twelve to give $22.4 M.

The calculation assumes that all of the reduction in the Queensland spot market price from 2000 to 2001 is attributable to QNI. This assumption appears to be based on the work of Bardak (although it is not at all clear which came first).

Bardak's work is based on the case study provided by the fact that:

> '*The first six months of the calendar year 2001 provides a small but revealing case study of the effect of a regulated, free-flowing substantial interconnection on wholesale prices in the NEM*[41]*.'*

The argument proceeds generally as follows:

- Time weighted pool price differentials between Queensland and New South Wales in the first six months of 1999 and 2000 reduced from approximately $32/MWhr and $25/MWhr respectively to only approximately $2.8/MWhr in the first six months of 2001.

- The significant reduction in spot market prices is due to the commissioning of the regulated QNI interconnection:

  > '*Compared to the previous identical periods in 1999 and 2000,* **the only changes** *which took place in Queensland had been the commissioning of a 180MW HVDC interconnection between the lower voltage transmission networks in northern New South Wales and southern Queensland in July of 2000* [i.e. Directlink]*, and the early stages of commissioning of a 420MW unit at Callide C*[42]*.*' [emphasis added]

  The impacts of both Callide C and Directlink on the Queensland spot market price are then dismissed viz '*their effect appears to have been small compared to that of QNI*', and all of the reduction is attributed to the commissioning of QNI.

The argument is precarious in that it focuses on available generation capacity as the only factor having an influence on spot market price outcomes. In fact a variety of other factors which Bardak has not attempted to analyze could have influenced the price outcomes. These factors include higher generation plant availability, lower demand, higher levels of contracted generation capacity, etc. Irrespective, this paper follows Bardak's approach, and focuses on the available generation capacity.

[40] Obtained from NEMMCO market data
[41] QNI Paper 2, page 1
[42] QNI Paper 2, page 2

The regulated QNI interconnection was commissioned on 14 February 2001 with an initial capacity of 300 MW, rising to 750 MW in late June 2001. For the purposes of the following discussion it is convenient to consider the first six months of 2001 as being made up of two distinct periods viz the 'pre QNI commissioning' period i.e. pre 14 February 2001, and the 'post QNI commissioning' period i.e. after 14 February 2001.

6.1.1.1.2.1.1 The Pre QNI Commissioning Period

It is incorrect to state that the commissioning of Directlink and Callide C were '*the only changes*' which took place in Queensland in the first six months of 2001. NEMMCO confirms that there was also an increase of 412 MW in existing summer generation capacity between 2000 and 2001[43]. Figure 4 also confirms that the 180 MW Directlink market network service operated consistently throughout the pre QNI commissioning period, while Figure 5 confirms that the 420 MW Callide C operated only intermittently. The new generation capacity operating consistently available in the pre QNI commissioning period therefore totaled 592 MW.

Analysis of NEM data confirms that QNI operated for only 129 out of 2131 half hour intervals prior to 14 February 2001 (refer to Figure 6). Combined with the fact that many of the initial times of operation occurred off-peak (i.e. either early in the morning or late at night), it is difficult to see how QNI operation could have had any substantial impact on the spot market price prior to 14 February 2001[44]. However, Table 7 gives the average Queensland and New South Wales spot market prices for each of the years 1999, 2000 and 2001 for the period 1 January to 14 February. Obviously any conclusions based on the data of Table 7 need to be tempered by the short sample period, but it is interesting to note the following:

- There has been a substantial reduction in the Queensland spot market price in 2001 even before QNI was commissioned. A complete analysis of this price reduction has not been carried out, but it is consistent with the presence of the additional 592 MW of new supply capacity.

- There has been a substantial increase in the 2001 New South Wales spot market price, so substantial that NSW is in fact more expensive than Queensland. Once again, a complete analysis has not been carried out, but this increase is consistent with the fact that the start of 2001 saw the end of the Victorian vesting contracts, which led to considerable spot market price increases in the southern states, including NSW.

[43] NEMMCO, '*2001 Statement of Opportunities'*, 30 March 2001, Table 4.3, page 4-10

[44] Bardak assumes that Callide C's intermittent operation has no impact on Queensland spot market prices in the pre QNI commissioning period. Consistent with his argument, QNI's intermittent operation in the pre QNI commissioning period should also have no impact on Queensland spot market prices.

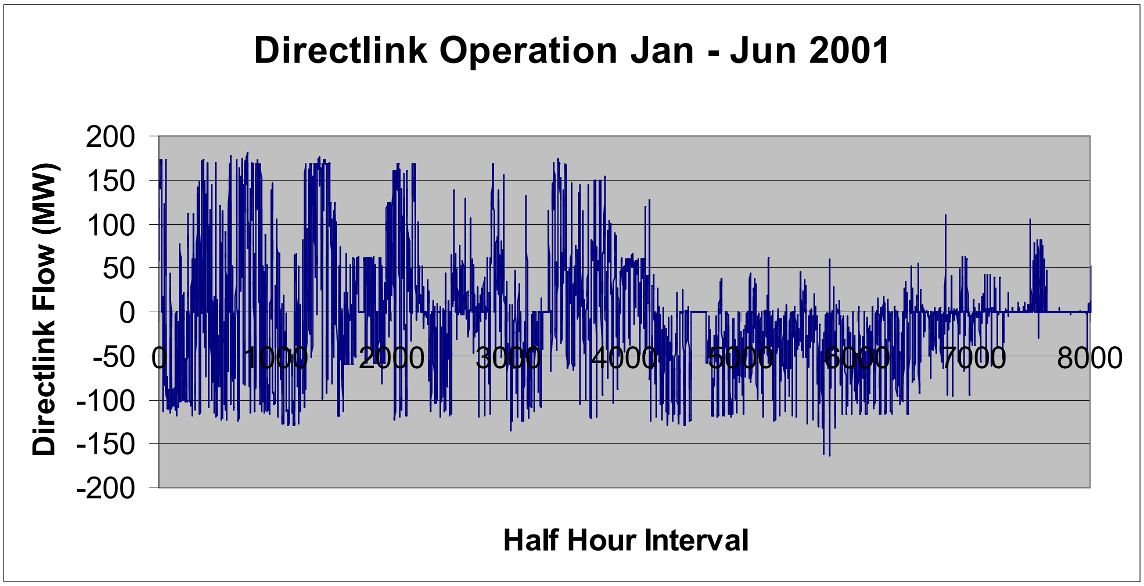

Figure 4 Directlink Market Network Service Operation

Year	QLD	NSW
1999	77.75	22.82
2000	84.65	37.94
2001	55.24	59.18

Table 7 Average Spot Market Prices ($/MWhr) 1 Jan- 14 Feb 2001

The evidence is therefore that there were substantial reductions in the 2001 Queensland spot market price even in the pre QNI commissioning period, and obviously these reductions cannot be associated with QNI.

The spot market price reductions are consistent with an increase in supply capacity delivered through the 412 MW increase in the capability of the existing generation plant and the 180 MW of the Directlink market network service, although other factors may also have contributed.

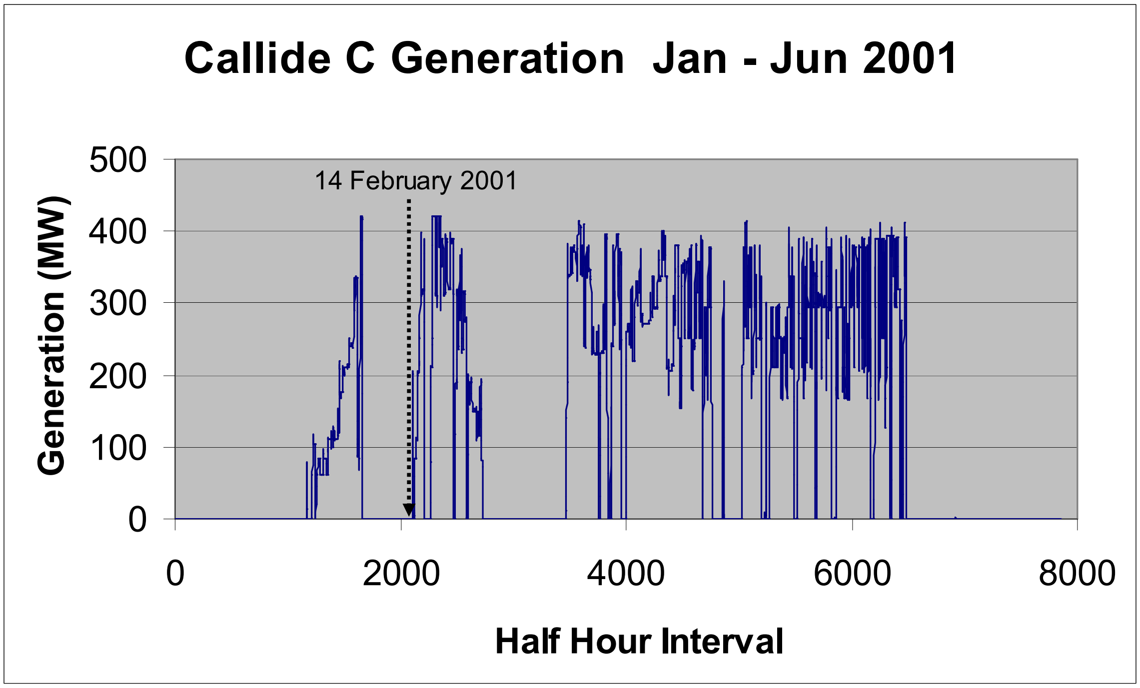

Figure 5 Callide C Power Station Operation

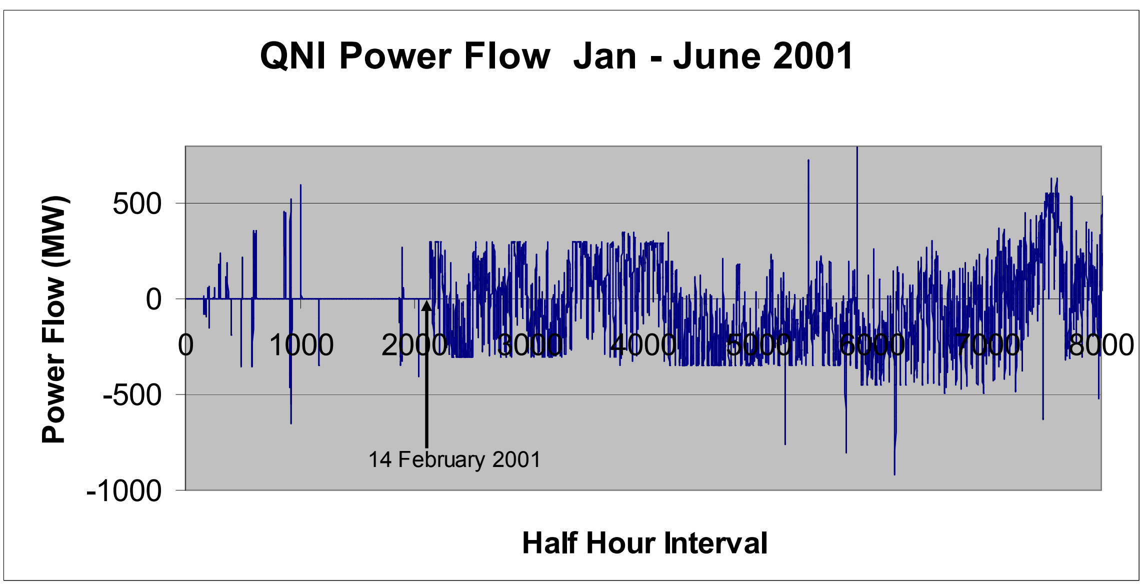

Figure 6 QNI Power Flow

6.1.1.1.2.1.2 The Post QNI Commissioning Period

QNI was commissioned on 14 February 2001 and Figure 6 highlights its sustained operation from that date. Figure 5 highlights that Callide C also had sustained levels of operation after 14 February 2001 (even though, as Bardak comments, it was still in '*the early stages of commissioning*'). Therefore new supply capacity in the post QNI commissioning period totaled 1762 MW as follows:

- An increase of 412 MW in the capacity of existing generation plant;
- The 180 MW Directlink market network service;
- The 420 MW Callide C power station; and
- The 300 to 750 MW of QNI, as it came into service.

It is assumed that all of these supply options contributed to varying degrees towards the significant reduction in Queensland spot market prices post 14 February 2001 (no attempt will be made to try to attribute a proportion of the reduction in Queensland spot market price to any individual supply option).

What is clear is that Bardak's analysis is insufficient to be able to state that the reduction in the Queensland to New South Wales pool price differential in the first six months of calendar year 2001'*has primarily been the effect of QNI*[45]'.

At this point it needs to be re-iterated that the discussion has focused only on new supply options and their potential impacts on spot market prices simply because that was the approach adopted by Bardak. Further investigation could confirm that other factors (e.g. higher generation plant availability, lower demand, higher levels of contracted generation capacity, etc) could also have played a major role in delivering the spot market price reductions.

6.1.1.1.2.1.3 Conclusion

This section has reviewed issues associated with the calculation of energy benefits under a broader definition. Its conclusions are as follows:

- Any supply option has the potential, but not the certainty, of delivering lower spot market prices.
- An observed price reduction cannot automatically all be attributed to a new regulated network service. Rather, the proportion that is due to the regulated network service needs to be specifically determined, taking into account all the relevant factors.
- At times, regulated network services may not lead to any spot market price reduction.
- Insufficient analysis has been undertaken by the proponents of the claim that QNI was solely responsible for the reduction in Queensland spot market energy prices that occurred in the first six months of 2001.

[45] QNI Paper 2, page 6

6.1.1.1.2.2 QNI Energy Benefit from a Reduction in Spot Market Energy Price Volatility

Bardak observes the reduction in Queensland spot market price volatility which occurred in 2001, and infers that it was primarily due to the commissioning of QNI[46]. It goes on to attribute substantial benefits (potentially up to $30/MWhr) to QNI as a result.

Powerlink also attributes the reduction in Queensland spot market price volatility to QNI, but does not attempt to quantify the benefit.

Others[47] have also noted the reduction in Queensland spot market price volatility which occurred in 2001, but have considered it in the broader market context. For example:

> '*it is apparent that the volatility across the market has in general declined since market start with significant reductions in the Queensland and South Australian markets. Since mid 2001, volatility in all four markets has been both of a similar level and character*[48]*.*'

It is evident that a substantial reduction in spot market price volatility occurred in Queensland in mid 2001. However, it should also be noted that significant reductions in spot market price volatility occurred not only in Queensland but also in South Australia, where no new regulated interconnector was commissioned i.e. there was not a 'QNI equivalent' event.

It is also interesting to note that:

> '*It is apparent that the volatility in NSW and Victoria has been similar since market inception…*[49]'

That is, although QNI connected into NSW, it did not further reduce the spot market price volatility in that state. One could reasonably therefore infer that interconnectors have absolutely no impact whatsoever on pool price volatility - although such a view would be rash without other supporting evidence.

The above discussion highlights that factors other than the commissioning of a new regulated interconnector affect spot market price volatility. For example, it has been observed that:

> '*The general trend is similar in all regions: RRP rises slowly as reserve reduces to 20% or 30% of maximum demand, and then below that it increases more sharply*[50]*.*'

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[46] QNI Paper 2, page 7
[47] John Field Consulting Pty Ltd, *Characterising pool price volatility in the Australian electricity market*, September 2003, available at http://www.neca.com.au/What'snew.asp?CategoryID=32&ItemID=1328 (**Volatility Paper**)
[48] Volatility Paper, page 3
[49] Volatility Paper, page 6
[50] Volatility Paper, page 21

This statement is best explained graphically. First, generator bids in a competitive market are accepted in order of increasing price. Therefore as the demand increases, higher and higher priced bids will be accepted until the demand and supply are in balance. The price versus demand curve will therefore generally be concave upwards as per Figure 7.

Figure 7 The Price Demand Curve

Assume first an initial demand of 0.5 per unit, giving a price of $35/MWhr. A 20% change in demand i.e. 0.1 per unit, moves the price to either of $28/MWhr or $43/MWhr. That is, a 20% change in demand delivers an equivalent 20% price change. Consider now a higher initial demand of (say) 0.8 per unit, where the price is $82/MWhr. In that case a 20% change in demand leads to prices of either $50/MWhr or $162/MWhr. That is, the 20% reduction in demand leads to a 32% reduction in price, while a 20% increase in demand leads to almost a 100% increase i.e. a doubling, of price.

The simple example demonstrates that the higher is the demand on the price demand curve, the higher is the price volatility associated with that demand i.e. the generator price stack, through the price demand curve, can magnify spot market price volatility

Other factors besides a change in demand (due to either time of day or weather effects) can also cause changes in volatility. These include:

- changes in generator fuel prices,

- changes in generator bids,
- outages of generation plant,
- the commissioning of new supply options (both generation and network service), and
- a combination of the above.

Now consider the reduction in the Queensland and South Australian pool price volatility that has occurred from 2001.

It has already been shown that Queensland experienced a substantial increase in supply side capacity in 2001 (1762 MW including QNI in the first six months of 2001, with the 420 MW Callide C Unit 2 first generating in July 2001). South Australia also experienced a substantial increase in supply side capacity (refer to Table 4). These substantial increases in supply side capacity in combination would have had the effect of shifting the steeply rising segment of the price-demand curve to the right, leading to a (substantial) reduction in pool price volatility. The other factors above may also have contributed to varying degrees. On that basis any claim that the reduction in Queensland pool price volatility was primarily due to the commissioning of QNI alone needs to be further investigated to confirm its validity.

The conclusion is that the calculation of energy benefits associated with a reduction in spot market energy price volatility is not at all straightforward.

6.2 Ancillary Service Benefits

Table 1 highlights that no regulated network service claimed any ancillary service benefits. However, substantial ancillary service benefits have recently been claimed to be attributed to QNI under the broader definition of competition benefits. The objective of this section is to determine:

- whether the claimed level of ancillary service saving is robust, and
- if the claims are not robust, what other factors (in addition to QNI) contributed to the ancillary service price reduction.

These factors will in turn illustrate the complexity of the calculation of ancillary service competition benefits.

6.2.1 QNI Ancillary Service Benefits

Bardak has claimed that under the broader definition of competition benefits recent data '*show[s] a very large reduction in Ancillary Services charges since QNI was commissioned*[51]. It acknowledges that this claim is sourced from Powerlink, who claims an '*ancillary services reduction of $2.5 – 3 M [per week] all attributable to QNI*[52]'.

Ancillary services fall into three main categories:

[51] QNI Paper 2, page 5
[52] QNI Presentation, Slide 20

- frequency control ancillary services (FCAS),
- network control ancillary services (NCAS), and
- system restart ancillary services (SRAS).

The evidence is that over time there has been a significant reduction in the price of FCAS. On the other hand prices for both NCAS and SRAS have remained relatively constant.

A large reduction in FCAS prices occurred in 2001. QNI was commissioned on 14 February 2001, and a market for FCAS ancillary services was introduced on 30 September 2001. Analysis performed by NECA has identified:

- '*pre-market ancillary service costs of ~ $3 M per week*[53]';
- '*typical pre-market (post QNI) costs around $1.8 M per week*[54]'; and
- '*average price since market of ~ $1 M per week*'.

On that basis it can be assumed that FCAS prices reduced by approximately $1.2 M per week (i.e. $ (3-1.8) M) around the time of the commissioning of QNI. However, this reduction may not be attributed solely to QNI. This is because generation plant is the primary source of FCAS, and the provision of FCAS is mutually exclusive to the provision of energy.

In that case generators need to trade off their potential revenues from participation in the energy market against their potential revenues from the provision of FCAS services. Therefore the pricing of FCAS consists of two components:

- the cost of actually providing FCAS (which is basically nil), and
- the opportunity cost associated with reduced participation in the energy market.

It has already been illustrated that prior to 2001 the opportunity cost associated with reduced participation in the energy market was substantial. Commensurately, the cost of FCAS was also substantial. However, the opportunity cost associated with participation in the energy market reduced considerably in the first six months of 2001 due to factors which include the commissioning of 1762 MW of new supply side options (refer to Section 6.1). This trend has been maintained through the commissioning of a second 420 MW Callide C unit in August 2001, followed in later years by the plant detailed in Table 5. The reduction in opportunity cost would also have flowed through to reduce the cost of FCAS.

On the basis of the available evidence it is therefore only possible to state that the reduction in the price of FCAS solely attributable to QNI is capped at $1.2 M per week at

[53] P. Adams, *The Performance of the ancillary service marketss,* 24 February 2004, Slide 2, available at http://www.neca.com.au/What'snew.asp?CategoryID=32&ItemID=1365

[54] NECA identified that for the 7 month period from the commissioning of QNI until the start of the FCAS market the actual FCAS cost was approximately $1 M per week. However, NECA concluded that the short sample period provided an atypical estimate, and that a more appropriate value was $1.8 M per week.

that time, and that the actual value going forward is probably considerably less than $1.2 M per week.

If further analysis is to be undertaken to better quantify this matter, then the following issues need to be addressed:

- '*Some potential participants may currently face barriers to entry because:*
    - *The form of market offers, or the requirements for participation, do not suit their technology;*
    - *The overheads of participation in ancillary service markets alone seem too great for parties not participating in the wholesale energy market; or*
    - *The services that they could supply would be called upon, or highly valued, so infrequently as to make the rewards for participation too low when compared to the risks that are involved in participation*[55]*.*'

  That is, it may have been more effective spending funds to reduce barriers to entry for providing FCAS, rather than spending funds on building an interconector.

- '*If the value, and supply, of ancillary services is largely driven by local requirements, with low cost supply to the national market being delivered almost as a by-product, then the treatment of local requirements may assume far greater importance than might first appear. Thus we should ask:*
    - *Should localized requirements be reduced by lowering reliability standards in situations where they apply, and/or a similar effect achieved by adopting more flexible cost-reflective standards, as discussed earlier?*
    - *Are there localized options, such as interruptible load, which are not being utilized to increase supply and reduce the incidence of high prices when local requirements are critical?*
    - *Should a more pro-active approach be taken to the recruitment of localized supply options, and if so, whose responsibility might that be?*[56]'

  For example, should greater encouragement be directed towards demand side participation, which it is understood is lower than expected, and even lower than before the commencement of the NEM?

- '*Regional [FCAS] contingency requirements are very often driven by the need to cover loss of interconnector flows, not generation*[57]'. TXU has quantified this further:

[55] CRA, *Review of Market Ancillary Services*, Submitted to NECA, January 2004, page 13
[56] CRA, *Review of Market Ancillary Services*, May 2003, page 11
[57] G. Thorpe and G. Read, *Review of Market Ancillary Services: Draft Conclusions*, Slide 19, 24 February 2004

> '*70% of contingency costs have been due to "local" contingency service requirements mostly associated with protecting against loss of a network element that constitutes part of an interconnector*[58].'

'*The FCAS cost of supporting interconnector flows should be a charge on the IRSS*' (i.e. inter-regional settlements surplus). '*It is part of the cost of providing interconnector service'* and '*it reduces the effective economic value of transfer*[59]'.

That is, there should be an FCAS charge against any FCAS benefit delivered by regulated interconnectors.

- '*Competitive spot markets for supply of some of these localized ancillary services seem unlikely*.' '*Non market services are already contracted*.' '*Financial contracting would have minimal impact on spot market operation, and market mechanisms (eg tendering) can still be employed in the contracting process.*' '*Limited contracting, eg by NEMMCO, seems likely to enhance performance/efficiency without significantly compromising market principles*[60].'

7.0 Conclusion

This paper has contributed to the debate regarding the Regulatory Test in two areas:

- it has reviewed benefits promised by regulated network services (in the theoretical calculation of the Regulatory Test) to determine whether they were actually delivered, and
- highlighted complexities associated with including competition benefits in the Regulatory Test under a potentially broader definition.

Deferred generation benefits were demonstrated to typically constitute the bulk of the promised benefits. Of particular concern is that very little of the promised deferred generation benefits appear to actually have been delivered. However, in retrospect this is not at all surprising, when one considers that deferred generation benefits ignore the competitive market dynamics which mean that different parties make the network service and generation investment decisions. Eliminating or reducing the deferred generation benefits from the Regulatory Test cost benefit analysis means that regulated network services face a real risk of not being justified. The ACCC needs to seriously consider the methodology employed to date by the proponents of regulated network services to ensure that the promised level of deferred generation benefits is more realistic.

A review of claimed competition benefits under a broader definition than the Regulatory Test presently permits highlighted that the claims were not robust. In fact the claims

[58] TXU, TXU Comments on Ancillary Services Review, Submission to NECA dated 4 July 2003, page 4
[59] G. Thorpe and G. Reid, *Review of Market Ancillary Services: Draft Conclusions*, Slide 19, 24 February 2004
[60] G. Thorpe and G. Reid, *Review of Market Ancillary Services: Draft Conclusions*, Slide 8, 24 February 2004

appear to be very simple, even to the extent of ignoring key aspects of the competitive market. The difficulties associated with calculating competition benefits under a broader definition need to be seriously considered both by the ACCC and market participants before any broader definition can be accepted and included in the Regulatory Test.