AER Submission

Transmission Frameworks Review

Issues Paper

September 2010

AUSTRALIAN ENERGY REGULATOR

Contents

Summary

The Australian Energy Regulator (AER) welcomes the opportunity to respond to the AEMC's issues paper on the Transmission Frameworks Review. This submission provides high level initial thoughts on the issues raised and the AER looks forward to participating in further discussions with the AEMC as the review progresses.

The AER monitors the wholesale electricity and gas markets and is responsible for compliance with and enforcement of the National Electricity Rules and National Gas Rules. The AER is also responsible for the economic regulation of electricity transmission and distribution services as well as gas transportation services. These roles leave the AER well placed to comment on the interplay between the competitive electricity market and the services provided by electricity transmission networks.

The AER strongly supported the conclusion of the AEMC in its Final Report of the Review of Energy Market Frameworks in light of Climate Change Policies that a broader review should be undertaken of the transmission framework, from the relationship between planning and revenues, to the pricing of services and the management of congestion. The AER considers that the strength of this review is its ability to consider a range of inter-connected issues together, removing the limitations imposed by looking at discrete sections of the framework.

The AER considers that the AEMC has correctly identified the scope of the matter in its issues paper. In line with the AEMC's request for an evidence based approach to this review, the main focus of this submission is presenting evidence on the impact of certain behaviour of generators and TNSPs which, while within the Rules, lead to less efficient utilisation of the network and less efficient dispatch of generation.

The AER considers that this evidence supports the need for continued reform to the transmission framework. In particular, the AER supports:

- the removal of incentives on generators to bid to the price floor and reduce ramp rates in the presence of congestion (referred to as disorderly bidding)
- enhanced incentives on transmission networks to maximise service capability
- greatly strengthened incentives on new generators to locate efficiently
- protection of transmission service delivery, particularly interconnector capability, when new generation is installed.

At this stage of the review process, the AER has not proposed any solutions to the issues identified. The AER supports the AEMC's preferred approach of developing 'packages' of options that can be assessed in a holistic fashion later in the review process.

1 Efficient management of congestion

The AEMC's issues paper asks respondents to present evidence that demonstrates how the current transmission framework works in practice. Accordingly, this section of our consultation response explores the effect of transmission congestion on market outcomes in New South Wales last summer. In particular, it shows how generator rebidding in response to congestion can greatly amplify the effect of transmission congestion on electricity prices. Whilst recent experience in New South Wales is used here as evidence, similar issues have arisen in different parts of the NEM frequently in the past.

1.1 Price outcomes – recent NSW evidence

New South Wales recorded spot electricity prices above $300 per megawatt hour (MWh) on 16 days between 7 December 2009 and 10 August 2010, including five days on which prices exceeded $5000/MWh. These events are detailed in Figure 1.[1]

Figure 1: Spot electricity prices above $300 per MWh in NSW over last 12 months

	Max spot price $/MWh	Duration of spot prices above $300/MWh (hours)	Number of 30 minute intervals above $5000/MWh
7 December 2009	9,175.60	5.5	6
8 December 2009	4,786.19	4.5	
16 December 2009	531.18	2.5	
17 December 2009	8,703.08	8	3
12 January 2010	1,331.79	4	
21 January 2010	376.27	0.5	
22 January 2010	4,514.06	7	
23 January 2010	2,562.20	2.5	
4 February 2010	5,540.90	2	1
11 February 2010	1,997.96	1	
12 February 2010	3,162.01	5.5	
22 February 2010	8,345.79	0.5	1
26 March 2010	1,835.69	1	
13 April 2010	3,080.54	0.5	
29 June 2010	4,686.99	0.5	
10 August 2010	6,266.50	1	2

1.2 Contributing Factors

A common factor in the events when prices exceeded $5000/MWh in New South Wales were network issues associated with managing flows across the Mount Piper to Wallerawang transmission lines. The Mount Piper lines are an integral part of the network that facilitates supply from Queensland, Victoria and the Hunter Valley into

[1] Most price events referred to in this paper occurred between 1 December 2009 and 28 February 2010. Prices also exceeded $300 per MWh on 26 March and 13 April 2010 (table 1).

the Sydney load centre, as shown in figure 3. The location of these lines means that congestion results in reduced supply from Queensland, Victoria and the Hunter Valley.

On three of these events (7 and 17 December and 22 February) high temperatures drove strong demand for electricity for air conditioning, which led to tight supply conditions. The other two events occurred at lower levels of demand, but network or generator outages exacerbated congestion on the Mount Piper lines that then led to tight supply conditions. [2]

While tight supply and demand conditions put pressure on spot electricity prices, they were not sufficient in isolation to cause extreme prices. Instead, these events set the preconditions for a chain reaction of responses from individual generators to minimise impact on them that significantly magnified the initial impacts.

As noted above, a common factor each day was a risk of overloading two 330 kV transmission lines that run between Delta Electricity's power stations at Mount Piper and Wallerawang (Mount Piper lines). High temperatures and/or outages on led to pressure on the Mt Piper transmission corridor and a tight demand/supply balance.

In order to manage these network limitations, the Australian Energy Market Operator (AEMO) was obliged to activate a constraint to prevent the Mount Piper lines from overloading on each of the high price days.

When the constraint on the Mount Piper lines became binding it forced a number of changes in the generation dispatch order to alter network flows. In particular, AEMO could no longer dispatch electricity in order of the cheapest sources, but had to take account of how that generation would affect the Mount Piper lines. This led to relatively cheap imports from Victoria and Queensland (and low-priced offers from other New South Wales generators) being restricted to avoid overloading the lines.

As outlined below, some generators were able to take advantage of these market conditions through rebidding, which further magnified the impact on spot electricity prices.

1.3 Generator rebidding

A significant issue of relevance for the AEMC's current review is the incentives that are created for generators to bid in a disorderly fashion on occasions when their dispatch is affected by network congestion, or a binding network constraint[3].

In this case, the binding constraint caused generation at the Mount Piper power station to be constrained off, with Wallerawang power station being constrained on. Delta Electricity, owner of Mount Piper and Wallerawang (together with other generation participants), raised market prices through a series of rebids (figure 2).

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2 On 4 February there were planned network outages in the Sydney CBD by Energy Australia that required reconfiguration of the transmission network. On 10 August there were no Wallerawang units in service, which increased flows across the Mount Piper to Wallerawang transmission lines.

3 A binding network constraint can cause generators to be dispatched at a price that is lower than its offer price (constrained-on) or generators to not be dispatched even though its offer price is lower than the regional price (constrained-off).

Figure 2 Rebidding on days where prices exceeded $5000 per MWh Demand and supply conditions—days when prices exceeded $5000 per MWh

Date	Delta Electricity rebids - capacity	Delta Electricity rebids - ramp rates	Rebids - other generators
7 December 2009	(1) Rebid 330 MW of capacity from below $115/MWh to above $8600/MWh, for the 1pm to 5pm intervals (2) reduced available capacity at Wallerawang by 200 MW from 1.35 pm to 6.30 pm due to 'dust burden'	(1) Rebid ramp down rates of Mount Piper units from 5 MW/min to 3 MW/min (2) Rebid ramp up rates from 5 MW/min to 10 MW/min	*Snowy Hydro* rebid 2000 MW of capacity from above $120/MWh to below $1/MWh to increase dispatch *Origin Energy* rebid 660 MW of capacity from above $9300/MWh to below $55/MWh to increase dispatch *Macquarie Generation* rebid 1430 MW of capacity into negative price bands and reduced ramp down rates
17 December 2009	(1) Rebid 100 MW of capacity from below $115/MWh to above $9600/MWh, for two trading intervals (2) reduced available capacity at Wallerawang by 100 MW due to 'dust burden'	(1) Rebid ramp down rates of Mount Piper units from 5 MW/min to 3 MW/min (2) Rebid ramp up rates from 5 MW/min to 10 MW/min	*Eraring Energy* (1) reduced available capacity by 70 MW (2) rebid up to 540 MW of capacity from $25 MW/h or less to above $9100/MWh *Macquarie Generation* reduced available capacity by 205 MW
4 February 2010	(1) Rebid 100 MW of capacity from below $115/MWh to above $9600/MWh, for two trading intervals (2) reduced available capacity at Wallerawang by around 280 MW due to 'dust burden'	(1) Rebid ramp down rates of Mount Piper units from 5 MW/min to 3 MW/min (2) Rebid ramp up rates from 5 MW/min to 10 MW/min	*Snowy Hydro* made several rebids of capacity and ramp rates during the day, including a rebid of 400 MW of capacity from below $0 to $10,000/MWh *Macquarie Generation* rebid its ramp down rate for some capacity to 3 MW/min, and its ramp up rate from 4 MW/min to 12 MW/min *Eraring Energy* rebid 240 MW of capacity from below $20/MWh to above $9700/MWh
22 February 2010	(1) reduced available capacity at Wallerawang by 500 MW due to unplanned outage	(1) Rebid ramp down rates of Mount Piper units from 5 MW/min to 3 MW/min (2) Rebid ramp up rates from 5 MW/min to 10 MW/min	*Macquarie Generation* rebid its ramp down rate for some capacity to 3 MW/min, and its ramp up rate by 8 MW/min
10 August 2010	(1) reduced available capacity at Wallerawang by 500 MW due to delayed return to service from outage		*Snowy Hydro rebid 1382 MW of capacity from above $285/MWh to close to the price floor to increase dispatch*

On the relevant days Delta Electricity typically:

- reduced the rate at which the Mount Piper power station could be ramped down when it was constrained off. The reduced ramp rate meant the power station responded more slowly than anticipated to being constrained off
- withdrew capacity from Wallerawang during the acute supply period. At the time Wallerawang was meant to be increasing supply in response to the constraint
- altered its offers to generate by shifting substantial quantities into extreme price bands (this occurred on three of the five days). Other generators also rebid capacity into higher price bands.

The capacity withdrawals and lower ramp down rates meant the Delta Electricity units did not respond quickly enough to the constraint on the Mount Piper lines, leaving open the risk of thermal overload. This obliged AEMO to apply the less efficient solution of constraining off more remote generation from the affected power lines. In particular, it restricted imports from Queensland and Victoria and constrained other New South Wales generators such as Bayswater.

While this helped to protect the Mount Piper lines it was a technically inefficient solution. The physical properties of electricity mean that constraining off a more remote generator requires a bigger supply cut than constraining off a generator that is close to the affected power line (figure 3). In relation to the price events in New South Wales, the affected generators and interconnectors were constrained off by a factor of three to four times what would otherwise have been required. On each occasion, a number of generators rebid large quantities of capacity to the price floor in response to being constrained off.

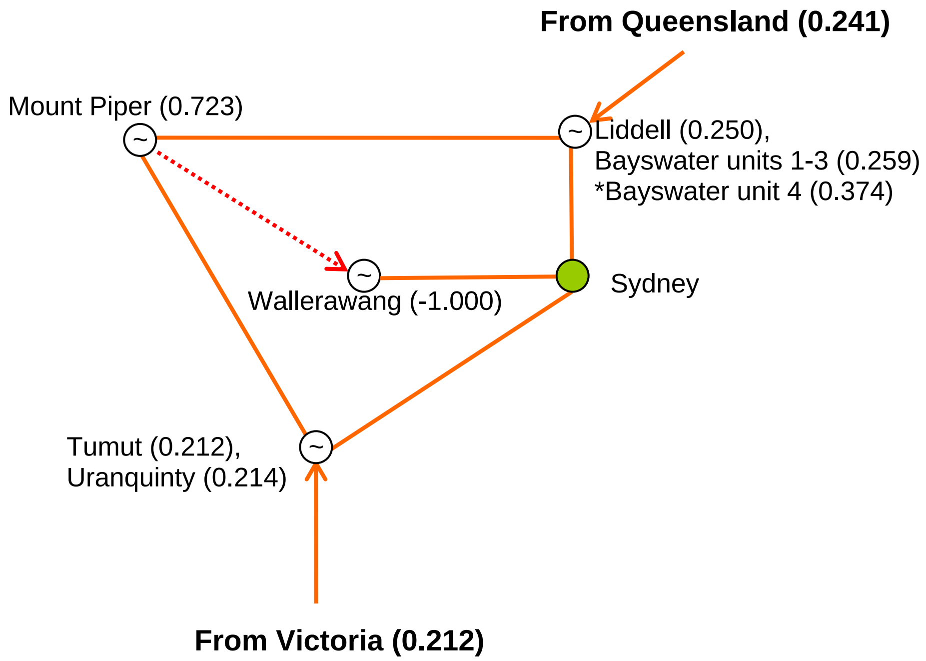
This exacerbated the already tight supply conditions and magnified the impact on prices. For example, import capability from Victoria and Queensland on 7 December was up to 2200 MW less than forecast 12 hours ahead. In addition, about 600 MW of low-priced New South Wales generation was constrained off. Across the four extreme price days electricity flows were forced out of New South Wales into Queensland and Victoria (contrary to market price signals) for significant periods.

These factors made the already tight market conditions in New South Wales even more acute. The situation was further aggravated when other generators such as Bayswater (owned by Macquarie Generation) also rebid down their ramp rates to delay the impacts of the constraints on their generation. There was also opportunistic rebidding by other generators to take advantage of the tight market (figure 2).

From late February 2010, in response to the market impacts of this network constraint, TransGrid put in place special arrangements to increase the ratings of the Mt Piper to Wallerawang lines. This allows for the lines to operate at a higher rating of 1430 MVA, previously the rating was 1097 MVA.

For the 10 August event, Wallerawang unit seven was returning to service, which required a network reconfiguration. This led to the lower ratings being reinstated. The reduced capability across the Mt Piper to Wallerawang lines combined with the lack of any output from generation at Wallerawang caused a potential overload despite the lower demand at the time. This again caused reduced dispatch of low-priced generation, forced flows out of New South Wales into Victoria and Queensland and led to the dispatch of very high priced capacity.

Figure 3 New South Wales transmission network — simplified



Note: The coefficients beside each generator indicate how efficient it is to ramp them up or down to address the constraint on the Mount Piper lines. A positive number (such as for Mount Piper) means the unit needs to be ramped down to address the constraint, while a negative number (such as for Wallerawang) means the unit needs to be ramped up. A larger number reflects more effective management of the constraint. For example, increasing supply at Wallerawang and reducing it at Mt Piper is more efficient than reducing supply from Tumut or Uranquinty. The least efficient option is to reduce supply from Tumut and Victoria.

In combination these events led to prolonged periods of extremely tight supply. As Delta Electricity had already rebid capacity into extreme price bands in anticipation of these events, the high demand and acutely tight supply drove prices into very high price bands.

These factors led to spot prices exceeding $5000/MWh for at least one interval on five days—7 and 17 December 2009, 4 and 22 February 2010 and 10 August 2010.

The AER estimates that during the fourth quarter of 2009 and the first quarter of 2010 the constraint related to the Mount Piper transmission lines was binding around 2 per cent of the time. The AER also estimates that the five minute spot price exceeded $1000/MWh around 25 per cent of the time when the constraint was binding.

1.4 Conclusions

The above analysis provides evidence that the Transmission Frameworks Review should investigate solutions to two inter-related issues:

- the incentives on generators behind constraints to bid to the price floor and reduce ramp rates to minimum levels (disorderly bidding)
- the need for further refinement of the transmission performance incentive scheme.

The second of these two issues is discussed in detail in the next section of this submission.

Although the above analysis focussed on recent market outcomes in New South Wales, the AER notes that very similar behaviour has occurred across the NEM at different times.

In relation to disorderly bidding by generators, the AER is concerned that these market impacts are neither efficient nor predictable and could pose a threat to the stability and safety of the power system. A number of market participants – including several Queensland generators – have raised similar concerns[4].

At its core, the issue of disorderly bidding is caused by the regional pricing model of the NEM, where generators are able to access the regional reference node (RRN) price in their region, regardless of any intra-regional congestion.

The non-firm access to dispatch model that currently exists in the NEM means that generators do not currently have any particular “right” to access the RRN. However, for any quantity that they are dispatched for, they do receive the RRN price. Accordingly, this provides very strong incentives to bid in a disorderly fashion to achieve maximum volume, whilst limited the ability of the market operator to reduce your output.

In previous reviews, solutions to the incentives on disorderly bidding behaviour were tied with discussion of the need for locational signals for generators and reforms to the regional pricing model of the NEM, including mechanisms similar to the Constraint Support Payment / Constraint Support Contract (CSP/CSC). Where these solutions lead to the creation of a more granular pricing structure, there is necessarily a discussion of how rights to the new “local” price are to be granted.

However, the AER is aware that some stakeholders (for example, the Southern Generators group) are developing more incremental models that use a more granular pricing model (similar to the CSP), but with settlement based on presented capacity. We understand that these models, which are based upon “a congestion management regime without allocating rights” were initially developed at the closing stages of the congestion management review. Whilst at this stage the AER does not endorse any particular solution, it is considered worthwhile examining such a proposal.

As discussed in the next section, one of the barriers to the development of enhanced incentive schemes on transmission networks is the lack of historical data sets. This includes determining effective measures of the costs of congestion. The removal of the incentives on disorderly bidding will lead to the true costs of congestion being more readily quantifiable, as discussed below.

[4] This was detailed in a letter from five Queensland generators to TransGrid on 23 April 2010, which was also sent to the AER and AEMO.

2 Economic regulation of TNSPs

There are a range of very technical transmission network factors that can affect the efficient dispatch of generation in the market. The TNSPs have significant discretion in making decisions which affect these technical factors. However, in the absence of some additional incentive mechanism, there is nothing in the revenue regulation framework that explicitly requires TNSPs to assess market consequences when making these operational decisions.

The events described in section 1 highlight two points:

- that operational decisions taken by TNSPs impact on the wholesale energy market

- TNSPs are able to respond to an incentive mechanism to reduce their market impact, as illustrated by TransGrid's action to increase the ratings of the Mt Piper to Wallerawang lines.

The extreme price events in the New South Wales electricity market in the summer of 2009-10 can be attributed to a complex chain of events. The underlying supply issue was that network constraints to manage electricity loads on the Mount Piper lines led to reduced output from low-priced generation and very high prices.

However, from late February 2010, TransGrid has put in place special arrangements to increase the ratings of the Mt Piper to Wallerawang lines. This allows for the lines to operate at a higher rating of 1430 MVA, previously the rating was 1097 MVA. The New South Wales example is only one example of the impacts of network congestion on market outcomes[5]. Unlike in other regions, however, TransGrid is a party to an incentive regime that rewards TNSPs for reducing the market impact of transmission congestion. TransGrid's response highlights that TNSPs are able to respond to incentives to minimise their impact on the market.

This section of the submission outlines the development of the AER's service quality performance framework for TNSPs. This is followed by a description of some of the issues and steps the AER is exploring for refining the availability and reliability parameters and for promoting greater recognition of the impacts of TNSP performance on the wholesale market.

2.1 Reliability incentive framework

In 2003, the Australian Competition and Consumer Commission released its Statement of principles for the regulation of transmission revenues—service standards guidelines. The AER subsequently adopted these guidelines as part of its compendium of regulatory guidelines. These guidelines were focused on promoting reliability of the transmission network and did not directly address the market impact of transmission congestion.

This approach was largely retained in the August 2007 service target performance incentive scheme (STPIS). Where a TNSP improves its performance against the

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[5] See "Investigation into the derating of the Heywood interconnector in November–December 2007"; "Investigation into the events of 16 January 2007"; "Investigation into the events of 31 October 2005" at www.aer.gov.au

performance parameters in the STPIS it is rewarded, where performance declines the TNSP is penalised. The maximum reward or penalties under the STPIS have been relatively modest and were initially set at plus or minus one per cent of the revenue cap.

A TNSP's service quality performance is assessed against the following availability and reliability parameters:

- transmission circuit availability
- loss of supply event frequency
- average outage duration.

In applying the above parameters, the AER has been mindful of making use of available information to develop the definitions for each parameter. Historically TNSPs have collected performance data mainly for internal management purposes and reporting to state regulators. They were not required to collect data based on a uniform set of performance parameters, and therefore no two TNSPs have collected exactly the same data. This has led to the need for definitions that would measure broadly the same parameters yet offer some flexibility.

As more data is gathered on existing parameters and the effects of differences in definitions on performance incentives become more apparent, the AER will work towards standard definitions of the performance parameters, so to ensure that TNSPs face similar incentives.

The AER has identified some limitations with the existing availability and reliability parameters. For example, in many cases reduced circuit availability and higher outage levels do not directly affect customers as virtually no outages cause blackouts. This led to the development of a market impact parameter, as discussed below.

2.2 Development of market impact measures

In June 2006, the AER published three congestion indicators; total cost of constraint (TCC), marginal cost of constraint (MCC) and outage cost of congestion (OCC). In June 2007, the AER released an issues paper that reviewed the MCC, OCC and TCC data that had been gathered to that time and outlined various options to develop a market impact parameter for inclusion in the incentive regime.

In March 2008, the AER published a final decision which added a proposed market impact parameter to the STPIS based on the MCC indicator[6]. The market impact parameter supplements the initial STPIS by targeting outages that have an adverse impact on dispatch outcomes and provides financial rewards for improvements in performance standards against target. The TNSP currently faces no penalty if it can not meet the target.

The AER considers there is scope to explore other parameters to deal with market impacts such as requiring rating capabilities to be attached to planned transmission augmentations. The AER has also been following AEMO's development of the

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[6] The availability and reliability parameters of the STPIS remained unchanged at this time

Congestion Information Resource, which could be used to develop other market impact parameters. The potential to strengthen the existing market impact parameter is also being considered. Some of these options are listed below.

2.3 Overseas developments

There may be potential to strengthen incentives on TNSPs to manage networks more efficiently and to maximise operational network capability for the benefit of the market. This could be achieved by specifying in the regulatory framework the outputs that a TNSP's investment program is expected to achieve and attaching financial rewards and penalties to over and under performance. Outputs-based regulation could help to ensure that customers receive value for money when they fund network investment via the revenue determination process.

The AER notes that the UK energy regulator, Ofgem, is conducting a major program of work to make its revenue determinations more focussed on the outputs delivered by network operators. Ofgem introduced an outputs based incentive mechanism as part of its latest electricity distribution price control and proposes further reforms as part of its RPI-X@20 review.

In electricity distribution, Ofgem agreed with each network operator a package of site/asset specific network output measures that correspond to the company's investment plans.[7] If a network operator fails to deliver the agreed level of outputs, Ofgem will make an adjustment to their allowed revenues at the next revenue reset.

In the RPI-X@20 review, Ofgem proposes to adopt two tiers of outputs—primary outputs (specific targets associated with high level objectives such as customer satisfaction, reliability and safety) and secondary outputs (which relate to expenditure that delivers primary outputs over the long term i.e. during future price control periods).[8] Ofgem is currently considering specific targets to apply to each sector that it regulates, including electricity transmission.

The Transmission Frameworks Review represents an opportunity to consider whether outputs based regulation could enhance outcomes in the NEM. Recent developments in the regulatory framework have the potential to complement a greater focus on outputs. In particular, the National Transmission Planner would be well placed to take on a role in assessing the level of outputs to be delivered by TNSP investment programmes.

We note, however, that the approach adopted by Ofgem carries potential risks as well as benefits. By design, outputs targets influence TNSP behaviour. It would be important to carefully design the output measures so that they do not create incentives for TNSPs to behave inefficiently. Further, Ofgem's approach thus far has involved

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7 Ofgem, Electricity Distribution Price Control Review, Final Proposals - Incentives and Obligations, 7 December 2009. Available at http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/FP_2_Incentives%20and%20Obligations%20FINAL.pdf

8 Ofgem, Regulating energy networks for the future: RPI-X@20 Recommendations, 26 July 2010. Available at http://www.ofgem.gov.uk/NETWORKS/RPIX20/CONSULTDOCS/Documents1/RPI-X@Recommendations.pdf

detailed regulatory involvement in TNSP investment programs, and represents a shift towards a more centralised style of decision making.

2.4 Future developments

As noted above, it has always been recognised that the STPIS model would be developed over time. Depending on the outcome of the AEMC's review process, the AER would expect to commence a review of the STPIS in the second quarter of 2011. This timing is due to the requirement that the STPIS must be in place 15 months prior to the commencement of the next regulatory control period in order for it to apply to a TNSP and the timing of the next revenue determination process for ElectraNet.

Issues to be covered by such a review could include:

- the level of the 'cap' on the incentives – is the plus or minus one per cent of the revenue-cap (for the reliability component) and plus two per cent (for the market impact parameter) sufficient incentive to improve performance
- the appropriateness of the current parameters, including investigating international regulatory developments in this area, as discussed above
- the weights attached to the various parameters—should the parameters be equally weighted? Has the addition of the market impact parameter created an overlap with the circuit availability parameter? Should the market impact parameter become a symmetrical parameter by rewarding reductions in transmission congestion and penalising increases in transmission congestion?
- managing incentives once a TNSP has reached the "natural limit" of any particular parameter—should the emphasis then shift to maintaining, rather than improving, service quality performance in such circumstances?
- recognising the impact of the allowed capital program on historical performance in targets—should there be "stretch" targets?
- how excluded events are identified and treated
- possibility of including incentives that relate to processing connection enquiries.

2.5 The need for better data and network information

Question 9 of the AEMC's consultation paper seeks views on whether further options for information release and transparency on network availability and outages should be considered.

The Rules impose a number of obligations on TNSPs to provide information to the market. Among other things, TNSPs must publish information on their planned network outages to help market participants make projections of market outcomes. It is important that the information provided by TNSPs is of sufficiently high quality for the market to be able to use it.

The requirement to publish information on planned network outages is subject to a number of qualifications that give TNSPs flexibility to diverge from their published plans. Clearly, TNSPs should not be compelled to adhere to a planned outage schedule if a change in circumstances means that there are legitimate reasons why the outage should not go ahead as planned. There is a need for qualifications, but if the qualification is too general it can undermine the usefulness of the provision (and also render the provision unenforceable). Poor quality information is of little value to market participants.

In 2008 the AER commenced a review of TNSP compliance with the provisions relating to market information on planned network outages. The review was prompted by the AER's market monitoring activities, which gave rise to concerns about the accuracy, consistency, completeness and timeliness of TNSPs' planned network outage information.

The review was not completed as the relevant Rules were amended as part of the introduction of the Congestion Information Resource. In practice, however, TNSPs' obligations to make available information on planned network outages has not changed, and the relevant provisions are still in force via the transitional provisions. Given this outcome, the AER considers that there are outstanding issues associated with the quality of the planned network outage information published by TNSPs.

To address these issues, we propose that AEMO publish indicators of the quality of planned network outage information published by TNSPs. For instance, AEMO could publish data on the accuracy and completeness of planned outages schedules published 1 month, 3 months and 6 months ahead over the previous 12 month period by TNSP. This approach would provide valuable information to market participants about the reliability of the information they receive. It would also create an incentive on TNSPs to improve the quality of the data they provide.

3 Network charging for generation

As noted in the first AER submission to the review of energy market frameworks in light of climate change policies, the electricity networks in most regions of the NEM were developed and configured around existing large coal-fired generators. As a result there are significant network assets associated with the transport of electricity from these generators to the load centres. In the long term, the implementation of climate change policies should lead to the retirement of coal-fired generation in favour of less emission-intensive forms of generation such as gas-fired and renewable plant.

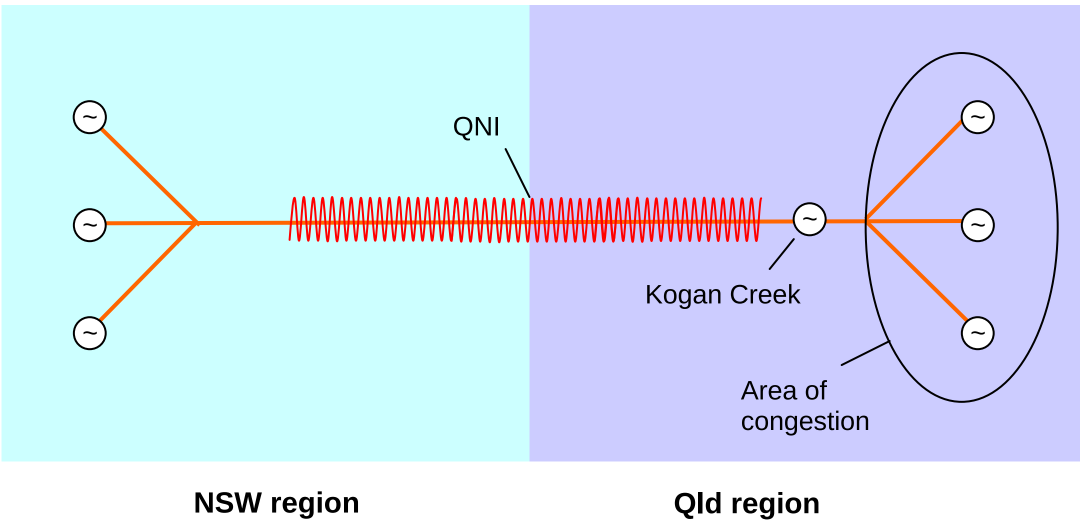
This section considers two connected issues: the need to ensure that the service capability of the transmission network is not compromised by the investment decisions of generators and that generators have long-term price signals to ensure an efficient pattern of investment over time (dynamic efficiency).

3.1 Protecting transmission service capability

The AER agrees that generators do not see the costs they impose on the shared network through their locational decisions.[9] There is evidence that some generators in the NEM have chosen to site their assets in locations that are not efficient from a broader network perspective.

This can be illustrated using the example of Kogan Creek, which is a 760MW coal plant commissioned in mid 2007. As depicted in figure 4, Kogan Creek is located in Queensland between the Queensland/NSW interconnector and an area of congestion on the transmission network.

Figure 4 Location of Kogan Creek on transmission network



In the absence of production from Kogan Creek, northward flows via the interconnector provide lower priced imports from NSW during periods of high prices in Queensland. However, Kogan Creek's production has had a significant impact on the northward flow capacity of the QNI. Figure 5 shows this relationship.

[9] AEMC, Issues Paper – Transmission Frameworks Review, 18 August 2010, page 27.

Figure 5 **Output of Kogan Creek and imports into Queensland across QNI, 1 January 2009 to 26 July 2010**

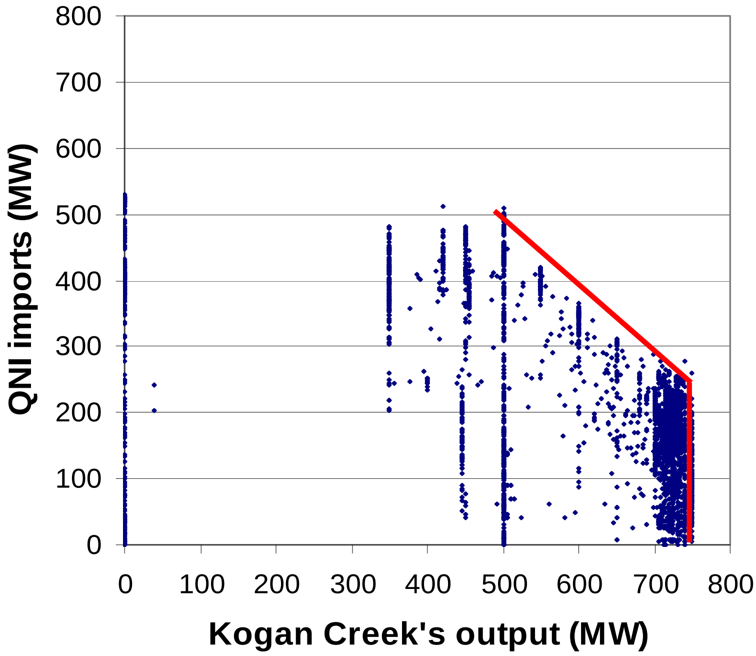


Figure 5 shows that as the output from Kogan Creek increases from 500 MW to 750 MW, imports across the QNI decrease on an almost one for one basis. When Kogan Creek operates at full capacity, imports from NSW into Queensland via QNI stop altogether. The result is that higher priced Queensland generation is dispatched instead of lower price NSW generation.

As noted in its second submission to the climate change review, to ensure the protection of transmission service capability the AER considers that as a general principle the regulatory regime should apply a ‘causer pays’ principle to connecting new generation. Subject to other efficiency considerations, this principle should apply to both ‘deep connection’ and ‘shallow connection’ charges as it assists in providing a strong locational signal and efficient market outcomes.

In the Kogan Creek example, the location and unit size decisions of the generation business led to a reduction in inter-regional trade capabilities (imports into Queensland) and increased frequency control ancillary services (FCAS) costs (borne by all market generators) following connection of the unit. The impact is not just within a region. Kogan Creek is now the largest generating unit in the NEM and has resulted in a larger requirement for FCAS across the NEM.

The Electricity Rules establish an automatic access standard which, if met by the connecting generator, prevents a network service provider from denying access to the network. If the automatic access standard is not met in the connection proposal, the connecting generator and the network service provider must agree on a negotiated access standard. This negotiated standard must be ‘no less onerous’ than the applicable minimum access standard as established in the Electricity Rules.

As noted in previous submissions, the AER considers that significant improvements to market outcomes may be achieved by raising the minimum standard to the automatic access standard, which prevents connecting generators from degrading inter-regional or intra-regional[10] power transfer capabilities. This would mean that the business decisions of connecting generators do not impact on the efficient operation of interconnector assets and would protect transmission service delivery. These impacts would be relatively straightforward to model and assess in response to a connection application.

3.2 Long-term signalling for generation investment

In the climate change review, the AEMC recognised the need for mechanisms to be developed that would incentivise intending generators to locate efficiently. While the connection charging arrangements create an incentive for generators to locate close to the transmission network, generators do not receive a price signal that reflects the level of congestion at the point on the network at which they connect.

For example, the decision to locate a gas-fired generator at Uranquinty in New South Wales highlights the potential inefficiencies created by the current lack of locational signals. Uranquinty is effectively at the same location in an electrical sense as the Snowy generators. As network constraints regularly occur between Snowy and Sydney at times of high demand, locating generation at Uranquinty does not add any extra capacity to the Sydney load centre.

A further example is the decision to locate a large quantity of wind generation in the south east of South Australia. The Heywood interconnector is often constrained between the location of these generators and the Adelaide load centre. These wind generators, however, receive the South Australian spot price ahead of generation in Victoria.

The AEMC’s final report on the climate change review proposed a “straw man” in the form of the G-TUOS model. This model would have provided long-term signals for intending generators to assist in an efficient pattern of generation investment. Whilst the AER was broadly supportive of such a mechanism, it did recognise issues with its development. In addition, many stakeholders raised concerns with the idea of generators being subjected to a use of system charge, without any particular level of service being guaranteed.

Whilst the G-TUOS model may not be found to be the most appropriate mechanism, the AER considers that some form of enhanced locational signal should be developed as part of the AEMC’s current review. Regardless of whether generators are assured of a particular level of service from the transmission system, it is important that they face stronger signals to locate in efficient locations.

Such signals could take the form of transmission charges levied on generators (with or without associated access rights) or the adoption of time limited constraint driven local pricing.

It was noted earlier that the Southern Generators are developing a model for settlement in congested parts of the network. Should the AEMC decide to develop that model further, it is noted that it does not necessarily provide the long term signals needed to ensure efficient location of new generation. Accordingly, some additional mechanism would be needed.

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[10] Schedule 5.2.5.12 - impact on network capability.