Investment and Congestion Management in the NEM

The purpose of this paper is to provide a participant's view on forward investments in generating capacity in the context of the Congestion Management Review being undertaken by the AEMC.

1. Introduction

The cost of network congestion appears to have been increasing each year, and this risk may become more difficult to quantify over time in the absence of investment in the transmission network. The anticipated uptake of significant levels of regionally concentrated renewable generation (as a result of the introduction of a national Renewable Energy Target) is likely to exacerbate this situation. But modifications to the manner in which the market operates, particularly those changes that would have the effect of increasing basis risk, would be a retrograde step for the market as a whole, and will lead to higher costs for new entrant generating plant, and therefore ultimately the consumer. The reason for this relates to the cost of financing power generating assets.

By way of brief background, Babcock & Brown has project financed the 286MW Oakey GT (2000), 151MW Redbank Coal-Fired Plant (2001), 455MW Braemar GT (2005), 320MW Kwinana CCGT (2005) and the 640MW Uranquinty GT (2007) amongst others, and has acquired the EcoGen (2003), Flinders (2006) and Alinta (20007) power generating assets.

2. Power Project Financings – is congestion relevant?

When any new power project is seeking debt and equity capital market financing, one of the most significant variables considered in the due diligence process is access to market – that is, the prospect and impact of network congestion. The 640MW Uranquinty project in New South Wales provides a case in point.

In the early phases of Uranquinty's development, a view was published by a network operator that the plant would not add to New South Wales' generating capacity, and in addition, would cause network congestion (a view which was later retracted). While this original view was at odds with those held by the project proponents, both the debt and equity capital market participants became aware of this 'view', and as a matter of course, further investigations were required by the equity capital proponents, and at a later point in time, the debt capital proponents. Results of the independent analysis undertaken for this purpose are attached as Appendix I & II. In summary, the independent analysis confirms three key points:

- Uranquinty adds to the reliability of power supplies in New South Wales and with high northward flows, "improves transient stability quite significantly";
- Increasing Snowy-to-NSW transmission capacity by 500MW has a negligible effect on the run time of the Uranquinty project (ie. Less than 30mins per annum), thus indicating that the plant is not significantly impacted by existing line limits; and
- Network constraints would be "very rare".

The view held by a small number of participants in the NEM that investments like Uranquinty are aimed at 'gaming' the regional pricing arrangements is both naive and unrealistic.

The economics of a power project are driven heavily by fuel and transmission connection, which then manifest themselves in output quantities and prevailing regional prices. If a project is likely to face network constraints, thus impacting either or both of these two key latter variables, then the overall projected revenues will be downgraded accordingly. This in turn will severely limit the level of debt that the project will be able to raise and carry. Since the (pre-construction) cost of equity is invariably higher than the cost of post-construction project debt, the weighted average cost of capital will simply yield the project uneconomic.[1]

3. Impact of Congestion on Power Project Financings

As noted in Section 2, if a proposed power project was likely to face significant network congestion, then both the equity and debt capital markets will not provide the requisite finance at any price. To infer that they would otherwise would suggest that the financial markets are incapable of risk identification.

If congestion forecasts for a power project were thought to be less significant but still material, then the level of project gearing will necessarily fall, which in turn will raise the weighted average cost of capital to the point of making the project uneconomic in any event. Once again, the project would be unlikely to proceed.

The more relevant question is how debt and equity capital markets view the prospect and impact of an insignificant (but still present) level of congestion. This has equal relevance to the refinancing of incumbent plant in the NEM – many of which are facing re-financings of some or all of their debt imminently.

Network congestion at the margins under current arrangements is in theory, and in practice, managed by the degree of hedge contract cover put in place at the outset. Consequently, any subsequent congestion impact on such a facility would be limited to an opportunity loss associated with the marginal output curtailed at the prevailing spot price – which to be sure, is usually high. Any number of existing power stations in the NEM experience this from time to time as a result of, for example, transmission plant outages, supply-side congestion, negative bidding and so on.

The current alternate methods proposed by some in the industry would have the effect of 'nodalising' the price of congested power stations during constrained periods. This of itself would ultimately lead to a dual impact on the profit and loss statement of a power station asset: firstly through lost quantity (as is currently the case), and secondly through a lower unit price across all dispatched quantities – the latter adversely impacting financial difference payments under hedge contracts. In effect, the NEM would introduce a new form of an intra-regional 'basis risk' that currently does not exist under the regional model of pricing.

While nodalising the spot price would, on economic efficiency grounds, mark a step forward for the physical market, it would clearly mark a retrograde step for the hedging market and therefore for the market as a whole.

In a logical illustration of the problem, consider the difference in losses that a 300MW peaking plant would face under a (for example) 100MW output reduction congestion scenario of regional price and a local-nodal price: under a regional pricing arrangement, at a value of $9900/MWh the opportunity loss would be around $1

[1] Note that the pre-construction cost of equity will be significantly higher than the post-construction cost of equity due to the added risk faced by equity participants during the construction phase of a power project.

million per hour (i.e. 100MW *times* Spot Price). Under a localised price which applies to the entire output, including that component that is hedged, it is feasible that without any understanding of the extent of constraint the difference across a one hour period could be as high as $3 million per hour (i.e. 300MW *times* Spot Price less nodal price). This loss would represent approximately 10% of the required annual revenue of a 300MW plant for banking purposes – unwound in the space of just 1 hour.

Ultimately, energy policy needs to focus on the underlying requirements of the stakeholders that it is trying to satisfy. Currently, the outlook for growth in power demand (both peak demand and energy demand) remains strong. Nowhere in the world has power demand been saturated on an ongoing basis. The existing plant stock is aging, and the oversupply that the NEM once thrived on has largely been exhausted. This points to a need for substantial increases in new capacity, both in the form of generation and transmission/distribution investment. Introducing basis risk within the regional pricing model will clearly do little to facilitate new investment, other than to raise new risks faced by project proponents, raise the cost of capital and therefore raise the new entrant price which ultimately defines what end-use consumers are, in time, charged.

4. Dealing with Transmission Congestion

In the short term, measures that improve the management of congestion and reduce the risks faced by generators on an efficient basis would be supported to the extent that they do not introduce further complexity or risks which are likely to be a focal point for asset financings.

At the very least, to the extent that events are caused through network maintenance, sharper signals are required to the owners of those businesses to shift maintenance from peak to off-peak hours – just as they exist (with great magnitude) in the wholesale spot market. But at the same time, the regulator of network businesses must also accept that there are incremental costs associated with shifting maintenance works from peak to off-peak hours, and enable such costs to be pulled into the network rate base.

From an efficient dispatch perspective, market mechanisms could be explored to improve the real time management of constrained power flows via the real time adjustment to settlement amounts of parties in a binding constraint equation in proportion to a share of the network capability, based on the constraint equation coefficients and generation presented to the market. Unlike the current arbitrary ‘tie break’ arrangements, this approach would apportion reduced output in proportion to the contribution of a generator to a binding constraint, creating more predictable and efficient dispatch outcomes, and removing distorted bidding incentives.

The further advantages of such an arrangement are that it would also:
- avoid introducing additional complexity through locational pricing;
- allow more accurate calculation of the true cost of congestion; and
- involve minimal implementation cost

Clearly it is uneconomic to build out all constraints and to that extent a certain level of congestion will always be present in the NEM. But this should not lead to the situation whereby congestion is only dealt with through the current inadequacy of the regulatory test. To date in the NEM, management of congestion has tended to deal with the short term and the symptoms of congestion, rather than view the root cause as a long term problem, i.e. the resource adequacy of transmission plant, and the adequacy of transfer capability between low and high cost regions and sub regions.

This latter point is particularly important in light of the key drivers of generation plant investment, viz. fuel, transmission, site, and then forecast market conditions – in that order.

The existence of congestion in the NEM is certainly well documented in public studies, and the most recent review by the Australian Energy Regulator indicates that the situation is deteriorating rather than improving. This should not surprise anyone. The expected uptake of significant levels of regionally concentrated renewable generation in the near term will materially alter this balance. Load growth also remains strong, and completing a standard investment in the transmission sector is (at least) as difficult as any other segment of the energy industry value chain.

Transmission investment in the NEM is undertaken under two general conditions, viz. to meet customer reliability standards, or where market benefits exceed costs (such as deferred generation investment, reduced production costs and avoided load shedding). And in its current form, network owners have no ability to recover transmission investments that respond to supply-side driven congestion.[2] The regulatory test must address how new transmission augmentation to cater for new generation investments (most of which will be driven by government policies such as greenhouse schemes such as the 20% RET) will be achieved without existing participants being congested out of the market. At some point customers will pay for either the augmentation or the cost of congestion in the market through higher locational pricing.

It is worth noting that Transmission costs represent about 15% of the end-user price of power. Generation costs are closer to 45% as measured on a time-weighted basis. The impact of a step increase in transmission investment in the NEM transmission system will at best shift the absolute cost of transmission by approximately $5.00/MWh given the current base, yet the differential in the unit cost of fuel between competing resources can be multiples of this. The impact on effective competition can be even greater, as was witnessed in Queensland in the two financial years ending 1999 and 2000, where load increased, generating capacity remained largely constant, and unit prices fell by almost $15.00/MWh as a direct result of a reasonably modest investment in intra-connect capacity between Callide and Tarong (an investment that otherwise would have likely failed the regulatory test at the time of commitment).

The concept of generators driving additional (deep) network connection beyond their own shallow connection costs, while provided for under the National Electricity Rules, is little more than a theory, and has never been witnessed successfully at any scale in the deregulated world of energy markets.

However, improvements could be explored to the current framework to ensure that transmission investment is undertaken on an efficient basis to support generation investment and provide greater certainty over ongoing physical access to the market. One solution could involve arrangements that seek to maintain existing network capabilities, by requiring any material network change to be designed and constructed to maintain the capability of the network to support inter-regional trade and maintain the market access of affected generators.

[2] If network owners were obliged to build out the incidence of supply-side driven congestion, it is possible that such obligations could be gamed if a firm had a sufficiently large balance sheet to take on the risk of delayed network augmentation.

These arrangements would improve access certainty for existing players and new entrants alike. However, funding of transmission by new market participants may need to be considered beyond the existing customer funded transmission framework to meet customer reliability criteria in view of the emerging pressures facing the NEM.

5. Conclusion

The key objectives of the NEM by design were the pursuit of productive, allocative and dynamic efficiency, as enshrined in the National Electricity Objective. By any measure, the NEM has been enormously successful in maximising productive and allocative efficiency. So much so that the NEM has been, and remains, a beacon for successful reform for governments around the world.

Understandably, the dynamic efficiency of the NEM has been much harder to measure because for much of its history, it was in a state of inherent oversupply with exceptionally well-built (monopoly utility) plant. A constant thorn in the side of the NEM has been congestion, transmission pricing, incentives and the resource adequacy of transmission plant. Until transmission operation and investment incentives are managed at the regulatory level in proportion to the total impact on average end-user electricity prices, and in light of the impact on efficient spot prices and hedge market implications, there is unlikely to be any significant change to the current environment.

One aspect that is clear to Babcock & Brown Power is that any further breakdown in the regional price of power, even if restricted to congestion events, will simply add to the uncertainty of power project financings.   This will in turn manifest itself in higher credit and risk margins on the debt and equity capital respectively – thus raising the cost of new entry for all participants. Over time, this will translate to higher energy costs to consumers