A Review of the Financial Risk Profile of Transmission and Distribution Companies in Australia

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1.0 Introduction

For many financial institutions recent reforms in the power industry have implied competitive generation and retail functions while the network service functions (ie transmission and distribution) have remained regulated monopolies. Consistent with their exposure to competition and market uncertainties, generators and retailers are viewed as relatively high risk. In contrast, network companies have been viewed as relatively low risk due to their perceived monopoly status, minimal competitive pressure and more predictable costs and revenues. This view has translated into lower credit ratings for generators and retailers than for network companies, and a perception that incremental capital investments by network companies have lower risk than comparable investments by generators.

However, network companies are also vulnerable to market and competitive pressures, and ignoring those pressures could lead to an overvaluation of the credit rating of network companies. This risk is particularly great for network companies making large investments in "safe" regulated projects that may in fact be subject to future market pressures. This paper discusses one example of such an investment, and notes that in competitive electricity markets (such as the National Electricity Market), no bulk power supply investment (generation or network) can be considered immune to market forces.

Network companies face a risk of losing customer load to local generation (such as on-site cogeneration projects). Such network bypass could lead to 'stranded' network assets that are not used at all, or used significantly less. In addition competitive markets have introduced considerable uncertainty into network planning, since generators make decentralized and independent decisions about where to locate new generation investments. This uncertainty in generation planning is normal (and expected) in a competitive sector, since the entire point of competitive electricity markets is to allow investors to independently respond to decentralised prices.

This uncertainty in generation investment and operation also leads to uncertainty in transmission utilisation. As energy producers and consumers respond to market price signals, the geographic pattern of production and consumption will change in ways that are inherently less predictable. These uncertainties lead to the real possibility of under utilisation of transmission assets. Under the optimal deprival valuation ("ODV") methodology used in the National Electricity Market (NEM), stranded transmission assets are written down in value by the regulator, and produce little or no regulated income. In essence, regulated transmission assets are exposed to market pressures and risks through the ODV methodology.

This market related risk is often understated in the credit analysis of traditional network service providers. Stranded asset risks mean that network companies may have a higher risk profile than financial institutions have assumed to date (particularly with respect to network investments that have considerably higher risk), and this needs to be taken into account when determining credit ratings.

This paper first considers the risks faced by generators and retailers in competitive power markets. These risks are also faced by 'non-regulated' network investments. The risks and uncertainties associated with regulated network investments are discussed, and the common position that such investments do not face market risk is shown to be incorrect. The discussion is illustrated using the example of the Queensland - New South Wales transmission interconnection. Recent plans by new Queensland generation entrants make this regulated interconnection a very high risk investment for its developers.

2.0 Competitive Power Market Risks

Participants in competitive power markets can be broadly classified as generators, retailers and network service providers. We consider in turn the risks faced by these participants.

2.1 Retailers and Generators

In order for generators and retailers to effectively participate in competitive power markets they must develop strategies based on preferred options. For example, buyers of power (eg retailers) must compare power prices under bilateral contracts against purchases on the spot market. Sellers (eg generators) need to be able to determine whether competitively priced power sales (either bilaterally or through the spot market) can produce sufficient revenue to cover costs. This challenge is particularly great when considering new investments. Both buyers and sellers must balance the cash flow certainty offered by contracts with the risks and rewards of buying or selling on the spot market.

The trade-off analysis balances the rewards and risks associated with each option. The results of the trade-off analysis may vary from one participant to the next, depending on the level of risk and uncertainty each participant associates with an option, and their own perception of future prices. It is recognised that some parties will make decisions (based on their trade-off analysis), sometimes with adverse financial implications due to unforeseen changing circumstances. (The simultaneous presence of upside and downside is the hallmark of competitive markets.) Recent Australian companies making the headlines as a result of past financial decisions include Loy Yang A Power Station and New South Wales retailer Integral Energy.

Generators and retailers are exposed to competitive pressures. The approach adopted towards managing those competitive pressures (eg the level of hedge contracts or the conservatism regarding future capital investments) determines the risk profile actually assigned to each company.

2.2 Network Services

The Australian National Electricity Code [1] defines both 'regulated'and 'non-regulated' network services.

The advantage of non-regulated network services to buyers and sellers of power is that the value of a non-regulated network service is effectively reviewed by the market place at every market dispatch interval (in the Australian market this corresponds to every five minutes). In essence, the spot market continuously values a non-regulated network service in accordance with the decentralised decisions of all market participants. In contrast, regulated network services are reviewed by the regulator (not the market), and the review is conducted only every five years (instead of every fifteen minutes). Thus if a non-regulated network service is not utilised or valued by the market there is no charge to the market participants, and the network service provider suffers financially. However, if a regulated network service is not utilised or valued by the market there is still a charge for the remainder of the regulatory review period, and the captive customers suffer from the cost of the under-utilised assets.

2.2.1 Regulated Network Services

Provided a network service is 'justified' under the terms of the Code the owners of a regulated network service receive a fixed, annual revenue from their investment during the review period. The regulator determines the revenue entitlement based on the optimal deprival valuation methodology [1]. Under this methodology any assets not fully utilised by the market are written down in value, and the owner does not receive a return on that investment.

The introduction of competitive power markets has added uncertainty to the provision and pricing of regulated network services, since the value of the regulated service is now exposed to market pressures (albeit indirectly). This fundamental shift in the valuation of regulated assets, and the associated market risk, calls for a shift in the financial profile of regulated network investments.

Historically, the role of the vertically integrated utility was to plan the integrated development of the power system, as the monopoly supplier of electricity in a given geographic region. In that role the utility planned both new generation plant and new network investment. This central planning was done in an integrated fashion. New generation was designated as base load, intermediate or peaking plant, based on its position in the merit order. With the level of operation of each generation facility known in advance with reasonable certainty it was relatively straightforward for the utility to both provide sufficient network capacity consistent with that level of operation, and to ensure that the network facilities would be well utilised over their lifetime. Since the utility planned generation as well as transmission, the transmission "needs" of the market were whatever the utility said they were.

With the advent of competition in the generation sector Independent Power Producers (IPPs) now plan new generation facilities in response to market forces (i.e., competitively set energy prices). In such an environment the network service provider has little information regarding the future location or level of operation of generation facilities (and no control over those decisions). The predicted use of the transmission system is much more difficult to determine. To further complicate matters the required level of network service is determined by the power market in response to generator bids. Therefore Network Service Providers (NSPs) run the real risk of augmenting the network in anticipation of new generation only to find the augmentation is not fully utilised. Another risk is that new transmission is constructed due to perceived supply deficiency in a given area, only to learn that new generation has been constructed in the deficient region. In either of these cases there is a high risk to the NSP that the investment will be written down in value by the regulator.

To provide a minimal "test" for regulated investments, a detailed comparison of all options is required for new network investments. Before an NSP makes a network investment on behalf of the market it is required to compare the benefits arising from demand side, generation and network options. The option that maximises benefits becomes the preferred option (refer to Clause 5.6.2 of the National Electricity Code [1]).

Even if the network service augmentation is the option that maximises benefits and the project is successfully constructed after the proper consultation process, the investment faces market risk. For instance, suppose a local generation facility is established at some time in the future, the benefits of the network augmentation may be reduced or even eliminated. In that case the augmentation would no longer be justified, and it could be expected to be optimised out for asset valuation and revenue determination purposes. This poses a significant financial risk to the NSP.

2.2.2 Non-Regulated Network Services

In contrast to regulated network services, non-regulated network services do not need to be justified under the Code. However, neither do the owners of a non-regulated network service receive a fixed, annual revenue for their investment as determined by the regulator. Rather, the owners of a non-regulated network service earn revenue by direct participation in the competitive power market, bidding 'transport' capacity in much the same manner as a generator bids 'generation' capacity. Therefore the risks and returns associated with non-regulated network investments are similar to those of generators.

3.0 Case Study

The Queensland - New South Wales interconnection (QNI) will be used as a case study to illustrate the risks associated with regulated network investments, and to illustrate that in competitive power markets, unpredicted generation development can significantly affect the benefits of transmission assets (and the returns to the regulated NSP).

3.1 Background

QNI involves the construction of a transmission line from the existing New South Wales transmission substation at Armidale (owned by Transgrid) to connect with Powerlink Queensland's existing network at Tarong. The interconnection is scheduled to be in service by October 2001 [2].

The total capital cost of QNI has been estimated at $409 million in 1997 dollars.

3.2 Justification

Consultants for Powerlink and Transgrid quantified costs and benefits from QNI as per Table 1. The table shows that QNI would result in net benefits of $135 million in net present value terms.

Table 1: Net Benefits of QNI [2]

The Net Benefits of QNI	Net present value ($m)
Benefits:	
Avoided generating capacity	571
Avoided transmission capacity	35
Energy trading	56
Total Benefits	662
Costs:	
Interconnect capital cost	382
Advancing transmission augmentation	19
Operating costs	101
Losses	25
Total Costs	527
Net Benefits	135

The most significant benefit arising from QNI is that of the avoided generating capacity which would be required to maintain a reasonable level of system security in Queensland and New South Wales in QNI's absence. This benefit constitutes $571 M of the total $662 M benefits ie 86% of the total benefits.

The consultant's report demonstrated that avoided generating capacity of at least 750 MW could result from the construction of a 500MW interconnect between NSW and Queensland. Approximately 450 MW of the 750 MW total would be located in Queensland while the remaining 300 MW would be located in New South Wales. Table 2 gives the timing and value of the benefits.

Table 2 Benefits from Avoided Generating Capacity [2]

NPV of avoided costs ($ million)

State	Year Avoided	MW	Total
Qld	2001/02	250	$224.7
Qld	2002/03	150	$125.6
NSW	2006/07	350	$220.3
Total		750	$570.6

3.3 New Generation Projects A number of IPP generation projects have recently been proposed in Queensland and some of these are listed in Table 31 . Table 3 is not necessarily exhaustive, but it illustrates that at least 4,510 MW of new generation capacity has been proposed for Queensland since Powerlink's and Transgrid's consultants concluded QNI would provide an avoided generation capacity benefit of $350 M in Queensland. In addition a non-regulated network service of 180 MW capacity is planned between New South Wales and Queensland.

1 The list of projects was compiled from public domain documents.

Table 3 Proposed Capacity Additions in Queensland

Project	Capacity(MW)	Timing
Acland	950	2002
Callide C	840	2001/2002
Gibson Island	350	2001
Kogan Creek	400	2002
Millmerran	420	2002
Oakey	300	2000
Tarong B	800	2001/2002
Wambo	450	2001
TOTAL	4,510	

While only some of the projects listed in Table 3 are likely to be constructed, it must be concluded that QNI will provide little if any avoided generation benefit to Queensland.

The generation projects proposed for Queensland are a response to market price signals. Assuming that New South Wales faces a generation deficiency in 2006/07 (as predicted by Table 2) there is no reason to expect that the market will not respond with new generation projects for New South Wales just as it has responded with new projects in Queensland. This calls into question the $220 M in avoided generation benefits (as per Table 2) to New South Wales.

3.4 Regulatory Review

The transmission regulator will determine the returns on the Powerlink and Transgrid investments in QNI. At present the regulators are state based, but over the next 2 years the Australian Competition and Consumer Commission (ACCC) will take over that role.

Avoided generation benefits make up 86% of the total benefits ascribed to QNI. Based on the preceding analysis little (if any) of these benefits are likely to actually materialise, and in that case the optimal deprival valuation methodology could significantly de-value QNI. This opinion is consistent with statements made by the regulator (ie the ACCC) when approving regulated status for QNI viz

'The regulated income stream …. will depend upon the Commission's assessment of the optimal value of those assets. As regulator the Commission may form a view that the value of the QNI assets is considerably less than the costs of construction' [3].

'The Commission notes that it is a real possibility that the asset bases of the transmission companies could be substantially devalued as part of the optimisation process if QNI proves not to be an efficient interconnector' [3].

Finally, it should be noted that no formal regulatory evaluation of QNI's costs and benefits has been conducted. Although QNI is deemed a regulated investment through derogations to the NEC, the ACCC has not set a value for the project, and could reasonably be expected to closely scrutinise the investment once it is first placed into service.

It is up to the regulator to determine what proportion of a regulated network service is justified. A simple approach would be that if a given proportion of the net benefits do not materialise an equal proportion of the investment should be disallowed. If none of QNI's avoided generation benefits are realised, QNI produces no net benefit. Therefore there would be a strong case for completely writing down the whole of Transgrid's and Powerlink's $409 million investment in QNI from its commissioning date. Thus, QNI could pose a very high risk investment to its developers, their shareholder and their lenders.

4.0 Conclusion

Investments in regulated network assets face considerable risks given the uncertainties of competitive power markets. Financial institutions need to realise that deeming a network service 'regulated' provides no guarantee regarding the return that the regulator will permit from an investment in that service.

It is concluded that in a competitive power market the risks associated with regulated network investments need to be re-rated, with a possible shift in the credit profile of network companies to match their actual risk in competitive electricity markets.

This market risk to regulated NSPs is greatest for investments that have the greatest number of competitive alternatives (such as regulated interconnections). QNI probably has the highest market risk of any regulated network service, as the competitive power markets in New South Wales and Queensland may significantly reduce (or eliminate) the ODV-determined value of QNI.

References

[1] National Electricity Code, National Electricity Code Administrator.

[2] Interconnection of the New South Wales and Queensland Electricity Grids, Submission to the ACCC, 24 September 1997, Transgrid, Powerlink Queensland, NSW Electricity Reform Taskforce and Queensland Electricity Reform Unit.

[3] ACCC, Applications for Authorisation, National Electricity Code, 10 December, 1997.