Merchant and Regulated Transmission: Theory, Evidence and Policy

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Abstract Economists acknowledge the problems of regulated transmission but take different views about the likely efficiency of merchant transmission. This paper examines the evidence on alleged market failure and regulatory failure as experienced in practice in Australia and Argentina. In these examples, merchant transmission (broadly defined to include private initiatives) has generally not exhibited the standard examples of market failure but regulated transmission generally has exhibited the standard examples of regulatory failure. Imperfect information – more specifically, in the form of lack of coordination – has often been a challenge whatever the approach. Policy should therefore seek to improve the regulatory framework and to remove barriers to merchant transmission and private initiatives. An important role for regulation is to facilitate coordination between potential providers and users of transmission lines.

Keywords regulated transmission, market transmission

JEL Classification L33, L51, L94

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1. Introduction

Electricity transmission used to be classified as a natural monopoly that needed to be regulated. Merchant transmission challenged this. Throughout its brief but eventful life, merchant transmission has been and continues to be controversial, in both theory and practice. Regulators internationally are now considering what role it should play in the provision of additional transmission, and what modifications to the regulatory framework are thereby indicated.

With the advent of electricity competition, explorations of optimal transmission pricing policy led to financial transmission rights and the possibility of competitive provision of transmission, financed by locational price differentials. (Hogan 1992, Chao and Peck 1996, Bushnell and Stoft 1996, 1997) Suggestions were made for the regulation of transmission companies. (Léautier 2000, 2001, Vogelsang 2001) However, changes in transmission technology were argued to shift the balance of advantage in favour of a market-based approach. (Rotger and Felder 2001) Hogan (1999, 2003) suggested that only 'large and lumpy' transmission investments should be regulated, with everything else left to the market. More recently, Hogan et al (2010) proposed a new regulatory mechanism aimed at combining the best properties of the merchant and incentive regulation approaches.

Joskow and Tirole (2005) (henceforth J&T) argued that the conditions required for merchant transmission investment to be optimal were not likely to be met in practice. Problematic aspects included wholesale market power, lumpiness of investment, strategic behaviour and difficulties of coordination. Admittedly the 'regulated Transco' model had various inefficiencies in practice, but it was unlikely that policymakers could rely primarily on the merchant model. Joskow (2005) argued that merchant transmission might be a complement but not a

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substitute for regulated transmission, was likely to make only a very small contribution, and efforts to debate its role had been a distraction.

European economists entering the debate took a more pragmatic and eclectic stance. Brunekreeft et al (2005) suggested that different solutions might be appropriate in different circumstances. For example, merchant transmission would be more viable in the US, with nodal pricing and financial transmission rights, whereas zonal pricing in Europe and Australia would restrict merchant investment to interconnectors between adjacent markets, with remaining investment being carried out by a regulated Transco. (See also Brunekreeft 2005) Rious (2006) suggested that merchant investment would be efficient where economies of scale were small relative to the size of market, where DC transmission had a cost advantage over AC transmission, and where differential prices could expect to be maintained, as in New York but not Australia. Competition for the market, along lines suggested by Demsetz, could be useful in radial but not meshed networks.

In 1998 two merchant interconnectors were proposed in Australia (DirectLink and Murraylink), which came into operation in 2000 and 2002, respectively. But both subsequently applied for transfer from merchant to regulated status, in Murraylink's case just two weeks after it came into commercial operation. Other merchant investments were projected, both in the US and in Europe, some of which have gone ahead. Their revenues typically derive from long-term contractual arrangements with regulated entities rather than from spot-market arbitrage between locational price differentials. Joskow suggested that they were more properly described as 'private initiatives', a useful term that we shall use herein.

Léautier and Thelen (2009) surveyed 16 restructured jurisdictions. They suggested that merchant investment has played a very limited role so far because (1) upgrades to existing capacity are not candidates while new interconnectors face regulatory and environmental barriers, and (2) merchant investment is not financially viable since a higher return is required for the risk involved, and construction reduces the price differentials that are the basis of potential revenue.

The pressures for transmission expansion and the option of merchant or private initiative investment are causing the Federal Energy Regulatory Commission (FERC) to reconsider its traditional open access transmission policy. (FERC 2011a) EU regulators too, faced with ineffective unbundling and insufficient new interconnectors, are allowing incumbent transcos exemption from EC rules on third party access in order to encourage investment. De Hauteclocque and Rious (2009) urge instead that dominant generators be allowed to make merchant investments, relying where necessary on the powers of the new Agency for the Cooperation of Energy Regulators (ACER) to address any competition concerns.

There seems to be common ground on the likely need for more transmission investment and the possibility that some form of merchant investment could play a role somewhere. However, there is apparently little agreement among economists as to whether this could or should be a relatively small or large role, and what kinds of policies are best suited to delivering this. The analytic literature is somewhat separate from the papers debating concrete issues of policy, and there is relatively little incorporation of empirical evidence into the theoretical papers.

Most of the analytic papers seek to characterise an optimal solution and to establish whether merchant transmission involves a departure from this. However, many of the features that are problematic for merchant transmission present problems for regulated transmission too. There is an alternative 'comparative institutions' approach (Coase 1955, Demsetz 1969, Kahn 1979) which has recently been powerfully expounded by Joskow (2009, 2010). This accepts that market and regulated approaches are both imperfect, and tries to identify and compare the pros and cons of each approach. In this way the evidence of experience to date is more easily considered and evaluated, in order to inform a general policy stance.

The present paper applies this approach to merchant and regulated transmission - taking merchant transmission in the broad sense, to include 'private initiatives'. It seeks to identify what have been the main market failures and regulatory failures, as predicted in theory and experienced in practice. It first examines experience with merchant and regulated transmission in Australia, where there is a direct comparison between the two types of interconnectors. It then examines experience in Argentina, whose 'beneficiaries pay' approach to transmission expansion has recently been adopted (with modifications) in the US. This sheds light on the question whether transactions costs are an obstacle to merchant transmission reaching an efficient outcome. The paper concludes by considering some implications for the general direction of future policy.

2. The potential imperfections of market and regulated transmission

The concept and main forms of market failure are well-known. J&T suggest various types of imperfection that they argue to be inconsistent with reaching an efficient outcome in the specific context of merchant transmission. Some of these imperfections apply also to regulated investment. For example, market power in the importing wholesale market can increase prices there and over-incentivise investment in transmission. But this is equally a problem for regulated transmission seeking to build the 'efficient' amount of transmission. In both cases, proponents of new transmission lines have to conjecture what factors have led to observed prices in the past and judge how far these factors will continue to obtain in the future. There seems no reason to believe that regulated interconnectors are systematically better at analysing these factors than merchant interconnectors.[2]

[2] Similar arguments apply to other potential imperfections such as the stochastic properties of transmission capacity and the associated definitions of property rights, network operator behaviour, and the implications of loop flow. These factors may be inconsistent with the

The potential imperfections of merchant transmission that cause most concern seem to be the following:

1) market power associated with a transmission expansion, reflected in lower capacity and output, delayed investment and higher prices;
2) lumpiness, leading to lower capacity and output because of the need to cover costs by locational differentials in prices;
3) imperfect information, resulting in misjudgements about what, where and when to build transmission;
4) transactions costs, resulting in inability to address problems associated with coordination and the aggregation of stakeholder preferences, negotiations between market participants, network deepening investments, gaming between interdependent entities and projects, and the separation of ownership and control;
5) long lead times and lack of forward markets and commitment, leading to difficulty of financing merchant interconnectors, lack of credibility vis a vis shorter projects, and regulatory uncertainty and opportunism.

J&T say that "In principle, a regulated Transco model can deal directly with issues associated with lumpy investment, market power in wholesale power markets, gaming behaviour of merchant investors and stochastic attributes of transmission capacity." (p. 262) But they immediately note that whether it can do so in practice is another matter.[3] In a more general context, Joskow (2010) identifies five types of potential regulatory imperfection. We may combine these suggested regulatory failures as follows:

6) imperfect information - about the regulated firms and also about the customers to be protected - leading to misjudgements about when, where and how to build transmission;
7) bureaucratic costs, time-consuming decision-making and problems of multiple regulatory jurisdictions;
8) less incentive to efficient construction costs, and conservatism with respect to new technologies and new and better ways of regulating;
9) interest group capture and political influence;
10) the possibility of inadequate resources to do the regulatory job well and consequent reliance on regulated firms.

How significant have these ten potential imperfections been in practice?

assumptions of the formal models used to justify merchant transmission, and they may be challenging problems in practice. But it is not clear that they are differentially more challenging for merchant than for regulated transmission.

[3] "However, a regulated Transco model will necessarily confront inefficiencies resulting from asymmetric information and political interference in planning and investment processes and may be less effective than a merchant model in providing the high powered incentives that lead to the identification of innovative transmission investment options, construction costs minimization and efficient tradeoffs between generation and transmission investments." (p. 262)

3. Regulated and merchant interconnectors in Australia

The next few sections draw on ideas and material previously set out at some length (and, I now realise, buried in a forest of somewhat impenetrable detail) in two working papers on regulated and merchant interconnectors in Australia. (Littlechild 2003, 2004)[4] These papers contain documented sources for the statements made below.

Electricity privatisation and competition began to develop in Australia during the 1990s, albeit on a somewhat piecemeal basis with varying enthusiasm in the different states. In 1996 a National Market Management Company (NEMMCO) was set up to be the short-term operator of the proposed National Electricity Market (NEM).

In 1997, the New South Wales (NSW) and Queensland governments announced a new regulated line between those two states, called QNI. This was an overground alternating current (AC) interconnector over a distance of about 550 km with a design capacity of 1000 MW south to NSW and 750 MW north to Queensland.

In 1998 a new entrant TransEnergie Australia (a subsidiary of the transmission entity of the Canadian publicly-owned Hydro-Quebec) and its partner Country Energy (a state-owned corporation in NSW), proposed an unregulated (i.e. merchant) interconnector between the two states, called DirectLink. This was an underground high voltage direct current (HVDC) line, over a much shorter distance of 65 km, and with a much smaller capacity of 180 MW.

DirectLink began commercial operation in July 2000. QNI commenced commercial operation in February 2001.

Over a similar period, there were also discussions between NSW and South Australia (SA). In 1996, the respective state-owned electricity entities Transgrid and ETSA agreed to explore the feasibility of an interconnector between those states. In June 1998 NEMMCO decided that their proposed regulated interconnector called SANI did not pass the prescribed regulatory test. SA withdrew. On 29 October 1998 TransGrid submitted a unilateral application for a revised regulatory interconnector called SNI.

On 28 April 1999 TransEnergie Australia announced its intention to build an HVDC merchant interconnector called Murraylink between Victoria and SA. It was shorter in length than SNI but along essentially the same route (the termini in Victoria and NSW being close together).

[4] The author was invited by Murraylink and TransEnergie to comment on part of the regulatory process in Australia in 2001, and was called by these companies to testify in the August 2002 hearing before the National Electricity Tribunal. Neither Murraylink nor TransEnergie provided financial support for subsequent work or for the writing of my 2003 and 2004 papers, and they are not responsible for the views expressed therein or here.

Murraylink (now jointly owned by TransEnergie and a Canadian private company SNC-Lavalin) opened for commercial operation on 4 October 2002. SNI did not go ahead.

4. Potential failures of Australian merchant interconnectors

a) Lumpiness and market power

Lumpiness does not seem to have been a factor limiting the size (or timing) of either merchant interconnector. Murraylink's 220MW capacity was not significantly less than SNI's 250MW. Directlink's 180MW capacity was significantly smaller than QNI's 1000/750MW. However, it was presumably constructed on the assumption that QNI would go ahead, rather than as a substitute, so it was actually only a marginal increase in total interconnector capacity. Both merchant interconnector capacities would be considered small compared to that of a new generation plant.

Did Murraylink have any market power? Did it delay investment, or restrict capacity or output, and consequently increase prices? For the most part, the answer to these questions seems to be No. As a new entrant, Murraylink had no interest in delaying investment to benefit incumbents. On the contrary, it deliberately incurred an extra cost to underground the line in order to avoid environmental objections and thereby speed up construction.

Three lines of argument and evidence as to Murraylink's market power were put before the National Electricity Tribunal. 1) That it would have an 18% share of flexible supplies in SA - which it never did. 2) That there was a constraint on gas-fired generation in SA - which was soon disproved by new entry. 3) That a consultancy study (commissioned by the incumbent TransGrid) suggested that in the absence of a contract with users Murraylink would reduce its flow by an average of 15-16% - but the same study showed that if Murraylink were 75% contracted, which was its stated policy and consistent with the policies of merchant generators generally, the average reduction in flow would be negligible (about ½ % of its capacity).

In the event, Murraylink was not able to sign any contracts and during its first year of operation its overall load factor was only about 14%. This was lower than the 50% load factors of two regulated interconnectors in Australia (QNI and Heywood). This suggests that, compared to a regulated interconnector financed by other transmission revenues, Murraylink did restrict flow in an attempt to maintain adequate price differentials in order to cover its costs of construction and operation. However, it failed: it could not make enough revenue to cover its costs. There is certainly no evidence that Murraylink was able to restrict output sufficient to extract monopoly profit.

Murraylink's low load factor probably reflected the very limited scope for profitable trade. It has been estimated that "such interconnectors require sustained Pool price differentials of $12 - $15/MWh even at full utilisation, to have a chance of earning a reasonable return on investment"[5] A 1997 study by London Economics had predicted a generation capacity shortage in SA and concluded that an interconnector between SA and NSW was economic. Over the four years from 1996/97 to 1999/2000 the differentials between the yearly average prices for SA and Victoria had averaged $21 – sufficient to make the interconnector viable if it were operating at about two-thirds capacity utilisation and ignoring transmission losses. In 2000/01 the differential fell to $12, implying that Murraylink would only be viable if it were assumed to run at full capacity all the time, and again ignoring transmission losses.

In the event, however, many of the assumptions of the 1997 study, including about capacity shortage in SA, were not fulfilled. In 2001/02 the differential between SA and Victoria fell to under $1. It averaged only about $6 from 2001 to 2006 before reversing to -$6 in 2007.[6] Such differentials are far below what Murraylink would need to cover all its costs, even with operation at full utilisation and zero transmission losses. And in practice these qualifications are significant: as noted Murraylink's overall load factor was only 14% and in 2003 its transmission losses were 6.9%. Ancillary services income was minor. Even if Murraylink could have been built without the additional cost of undergrounding, it would have had construction costs about double its prospective revenues. It is perhaps not surprising that Murraylink applied for conversion to regulated status on 18 October 2002. It was accepted as a regulated interconnector on 9 October 2003.[7]

Like Murraylink, DirectLink had no reason to delay investment. Like Murraylink, it had a low utilisation factor because it faced a significantly lower than needed average price differential. [8] Far from being able to restrict output to extract monopoly profit, it too made a loss. On 6 May 2004 DirectLink applied for transfer to regulated status, which was granted on 10 March 2006.

b) **Information, transactions costs and other factors**

It would seem that, in the case of both merchant interconnectors, TransEnergie Australia misjudged the market and had to exit at a loss. Why was this? Maybe

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[5] Booth (2003), p. 89. This is consistent with calculations made by the ACCC in 2003. $ figures for Australia refer to AUS$.

[6] Rious (2006) Fig 3 shows price differentials up to 2005/06 that are evidently calculated on a different basis but they equal $8/MWh on average, less than two-thirds of what would be required at full utilisation. He has different figures for the NSW-Queensland interconnector too, but the same conclusion.

[7] Interestingly, prices in SA significantly increased from 2007 onwards (following a generation asset swap, I am told). The differential increased to about $25 in 2008-2009, before dropping back to under $7 in 2010.

[8] The pool price differential between Queensland and NSW averaged about $18/MWh from 1998-2000. "[A] sustained average pool price differential of about $11/MWh would be needed to allow the owners to achieve a full commercial return. And this is with full utilisation – more practical utilisation levels would require a higher average pool price differential. // But since QNI has been commissioned, the Queensland - NSW pool price differential has been only around $2/MWh in 2001 and $8/MWh in 2002 - much less than that required to make DirectLink pay its way, given its actual low utilisation". Booth (2003), p.220. The differential was -$4 in 2003. Far from having full utilisation, DirectLink's overall load factor was 15% in 2001, 8% in 2002 and 27% in 2003.

TransEnergie's owner HydroQuebec and its partner Country Energy, as publicly owned utilities, were less sensitive to profit and loss than TransEnergie's other partner SNC-Lavalin. However, investment in these two interconnectors presumably had wider benefits for TransEnergie in terms of acquiring and publicising expertise in a new technology with a view to future business.[9] Perhaps temporary operating losses were a price worth paying. Murraylink noted that it would not have invested had it not been for the opportunity to convert to regulated status, which it said helped to avoid 'non-commercial market design risks'. Nonetheless, it would seem that imperfect information, in the form of over-optimistic estimates of generation shortages and future price differentials, played a part in the decision to build these merchant interconnectors.

The transactions cost issues mentioned by J&T do not seem to have been a problem for either merchant interconnector. These were what J&T call network expansions (interconnectors between networks) rather than network deepening investments. There was no need to coordinate market participants or aggregate stakeholder preferences. There was no gaming with other merchant interconnectors or power stations.

As regards the other factors mentioned, a long lead time with lack of forward markets and commitment was not an issue. In fact, the opposite was the case: the merchant interconnectors adopted a technology and design that minimised construction time and the possibility of delay due to environmental objections. Financing does not appear to have been a problem. There was no lack of credibility vis a vis shorter projects: any lack of credibility was on the part of the regulated interconnectors, one of which in the event was never built. Regulatory uncertainty and opportunism were indeed a problem for Murraylink to the extent that TransGrid persisted in proposing to build SNI despite growing evidence that it was uneconomic. Whether the then-regulatory body and appeal process would accept TransGrid's arguments was also uncertain. But neither of these factors actually stopped or delayed Murraylink. More on this shortly.

The evidence from Australia thus suggests that the decisions to build the two merchant interconnectors were questionable on commercial grounds. However, these interconnectors had essentially no market power. Nor were their developments characterised by the other potential market failures suggested by J&T. Far from building too little too late, the proponents built too much too soon - at least, too soon for their own good as operators. To the extent that the operating decisions can be taken on their own, apart from the desire to secure

[9] DirectLink and Murraylink were two of the earliest HVDC transmission links constructed by TransEnergie. Murraylink was an innovative technology and concept, was of record length and constructed in record-breaking time, and won environmental awards. The company subsequently participated in three HVDC projects in the US (Lake Erie Link, Harbor Cable between New York and New Jersey, and Cross Sound Cable between New England and Long Island). It advertised its expertise in "Innovative solutions for power transmission … We have a singular focus on the technical, commercial and regulatory aspects of interconnections across state and national borders." (www.transenergieus.com/projects.htm, accessed 18 November 2003). In addition, buying for several such interconnectors could conceivably reduce the list-price costs of equipment.

and demonstrate construction and operating experience with a new technology, imperfect foresight and perhaps public ownership seem to have been influencing factors.

5. Potential failures of Australian regulated interconnectors

a) Imperfect information

SNI and its predecessor SANI originated in state government decisions to build interconnectors. The 1997 study by London Economics found that additional capacity was required to meet demand growth in SA, and that an interconnector would be less costly than new generation. Other studies around this time supported this conclusion. But NEMMCO's formal review in June 1998 found that the SANI project was not justified under the original regulatory test, which referred to net benefits to customers. The test was revised to require that the proposed investment maximised the total net present value of the benefits to all who produce, distribute and consume electricity in the NEM. On 6 December 2001 NEMMCO accepted that a revised version of SNI satisfied the revised test.

SNI was never actually built. An equivalent project was evaluated as part of the ACCC's subsequent consideration of Murraylink's request for regulated status. The ACCC found that the SNI-equivalent project had the highest regulatory cost of all four transmission projects considered as alternatives to Murraylink. At $245m it exceeded the top end of the ACCC's credible range of benefits ($170m to $220m) of an interconnector. Together with Murraylink's actual experience as a lossmaker, this suggests that SNI would not have been an economic investment.

Similar reservations were expressed about the regulated transmission line QNI. Consultants for the proponents estimated in 1997 that the total benefit would be $662m NPV, of which $571m (86%) derived from 750 MW of avoided generation capacity, of which approximately 450MW would be located in Queensland. Yet by 2001 there were active proposals to build over ten times that much new generation capacity in Queensland. Not all of this would be constructed, but it cast doubt on how much generation the interconnector would avoid, and hence on the main reason why it was claimed to be economic. (Cook and Coxe 2001)

QNI's capacity was some four to five times that of DirectLink. It was estimated that QNI would require a sustained Pool price differential of about $5.50/MWh at full utilisation (about half the differential required by DirectLink) to achieve a commercial return on a merchant basis. In the event, QNI operated at about 50% utilisation in its early years, implying a need for a differential of about $11. The differential has fluctuated since then, in magnitude and even in sign, but never exceeding $11 and with an average absolute value of about $6 during 2001 to 2010.

The evidence thus suggests that imperfect information in the form of over-optimistic estimates of future price differentials was a significant problem for both the regulated interconnectors – at least, to the extent that their decisions reflected serious attempts to make economic investments. The actual objectives of regulated interconnectors are discussed further below.

b) Bureaucratic processes

A Memorandum of Understanding to examine the feasibility of an interconnector between the state-owned electricity corporations in NSW and SA was first signed in September 1994. After industry restructuring, a further such Memorandum was signed in August 1996 between the successor transmission entities TransGrid and ETSA Transmission. In June 1998 the quasi-regulatory body NEMMCO held that their proposed interconnector SANI did not pass the regulatory test. TransGrid submitted a revised application SNI on 29 October 1998 but on 30 July 1999 requested NEMMCO to suspend consideration of SNI pending finalisation of a revised regulatory test. TransGrid revised the design of SNI and on 6 March 2000 requested that the evaluation recommence. On 19 September 2001 a draft subcommittee report advised that SNI still did not satisfy the regulatory test. In October 2001 TransGrid further revised SNI to include more transmission reinforcement works in NSW. On 6 December 2001 NEMMCO confirmed that SNI now satisfied the regulatory test. On 21 December 2001 Murraylink applied to the National Electricity Tribunal for a review of this decision. On 31 October 2002 the Tribunal upheld NEMMCO's decision by a 2-1 majority. On 28 November 2002 Murraylink secured a judicial review of the Tribunal's decision. On 24 July 2003 the Victoria Supreme Court held in favour of the Tribunal on most grounds but in favour of Murraylink's appeal on two quite fundamental grounds, and remitted the decision back to the Tribunal for reconsideration.

The bureaucratic process for this regulated interconnector was indeed thus characterised by costly and time-consuming decision-making. Ten years after an interconnector was first mooted, and six years after SANI/SNI was proposed, there was still no decision as to whether it could go ahead. It was simply overtaken by events. The process was also characterised by costly legal appeals and reviews. In contrast, the merchant interconnector Murraylink was in commercial operation 3 ½ years after it was announced.

The process went more smoothly in the case of QNI, but was still time-consuming. An interconnector was first proposed in the early 1990s. The state governments of NSW and Queensland approved QNI in 1997, just before the National Electricity Code took effect, so that it was not subject to the same regulatory regime as SNI. Construction began in 1998. QNI went into initial operation in February 2001 and was scheduled to reach full capacity in 2002. This was about five years after the decision to build. Part of this reflects its larger size, but even so, the period was much longer than for the merchant interconnector DirectLink, which took about two years from announcement to commercial operation.

c) **Construction costs and conservatism in technology**

The differences between these four transmission projects suggest that regulated state-owned transmission companies are not as sensitive to the costs of large and time-consuming projects as are privately owned merchant transmission providers. Compare Murraylink as a 220MW 180km merchant interconnector costing somewhat over $177m including undergrounding, with SNI as a 250MW regulated interconnector over a length about double Murraylink's, which the ACCC estimated would cost around $245m. (This included about 30km undergrounding – Murraylink argued that SNI would need more than that.) And compare DirectLink as a 180MW 65km merchant interconnector costing some $130m including undergrounding, with QNI as a 1000MW 550km regulated interconnector with no undergrounding and costing some $350m.

The two regulated interconnectors used existing technologies. As noted, the two merchant interconnectors used novel technologies.

d) **Interest group pressures**

The incumbent state-owned transmission company TransGrid was evidently keen to protect and expand its operations and network capacity. The Tribunal Minority report commented that TransGrid's method of assessing projects would favour gold-plating.[10] At the same time TransGrid resisted incursion by the new entrant Murraylink. It is an interesting question whether TransGrid's conduct was consistent with its statutory objectives to operate efficient facilities for electricity transmission and to promote access to those facilities. Remarkably, in his evidence to the Tribunal, the Minister for Energy in NSW noted that those objectives did not impose any duties on TransGrid, hence expressed "no more than aspirations or ideals which are not enforceable by a court".

The influence of customer interests is intriguing. The original Customer Benefits Test was "designed to ensure that network investment would only be undertaken if customers benefited from that investment". In June 1998, finding that the SANI interconnector did not pass the test, NEMMCO noted certain problems with the test, and took the view that "the test, as it stood, might make it difficult for any inter-regional augmentation to satisfy the criterion". The ACCC, under pressure from NSW government, was asked "to recommend changes to the test to overcome the perceived inadequacies". Its consultants Ernst & Young pointed out that in some circumstances a test limited to customer benefits would actually be easier for a transmission augmentation to pass because the loss of generator monopoly profit would be ignored. Nevertheless, ACCC proposed a change to a Regulatory Test based on net public benefits or market benefits instead of net customer benefits, and this was implemented.

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[10] The Minority report drew attention to the failure to make valid comparisons between investments of different sizes, and the failure to distinguish between early occurring and more uncertain late occurring benefits. "Failure to make such adjustments for comparability will … systematically favour large projects, and so promote gold-plating". The failure to account for temporal uncertainty "is also likely to – and in the case of the sort of network investments under consideration here, very likely, and in this particular case would – lead to gold plating."

When it came to the regulated interconnector QNI in Queensland, consumer group pressure put the case for a regulated interconnector based on the benefits to customers, not on net public benefits or market benefits. For example, it was argued that "had DirectLink been the only interconnection, and had it been used to maintain a pool price differential of $11/MWh, Queensland, with 42,000 GWh of generation, would have sustained additional wholesale pool costs of over $460 million per year, enough to pay for the installation of QNI in just 12 months of operation." (Booth 2003 pp 220-1) This $460m is the approximate annual gain to Queensland customers.[11] But against this there would have been an approximately equal reduction in revenues to Queensland generators. (There would also have been higher prices in NSW, paid by customers there and received by generators there.) By the criterion of net public benefit, a regulated interconnector investment decision made on the basis of gains to Queensland customers would have been seriously inefficient.

e) **Political influence**

Until the early 1990s, each state in Australia owned its own electricity system, and there was little interconnection or desire for it. Thereafter, NSW was keen to promote interconnection in order to export its surplus generation, which meant greater revenues for the state-owned generators and their owner. A taskforce in Queensland, looking for it to join the NEM and restructure and privatise, proposed that the Government should construct a large interconnection with NSW, focusing on northward flow from NSW "to discipline generators in Queensland". South Australia, having suffered a blackout in 1993, was initially keen to construct a second interconnector to NSW, but when it decided to privatise the sector it withdrew its support. The original motivations for the regulated interconnectors were thus political as much as economic responses to the piecemeal privatisation and opening of the national electricity market.

Further political involvement included public commitments at Ministerial level and by the NEM Ministers Forum to greater interconnection between the States. The SA government pressed for action "to remove whatever road blocks there are and take some tough decisions on getting interconnectors in place". Construction of the (duplicate) regulated interconnector between SA and NSW/Victoria became an election commitment in South Australia. At the national level, the Council of Australian Governments commissioned a review whose outcome (Parer Report, December 2002) was very critical of arrangements for transmission. In the light of it, the Ministerial Council on Energy endorsed a package of radical reforms to electricity market regulation, not least of interconnectors, on 11 December 2003.[12]

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[11] It is approximate because in some hours the differential in prices would be even more than $11, even with DirectLink assumed to operate at full capacity, and in some other hours the differential would be less than $11, even with DirectLink assumed to restrict flow.

[12] The package included amendments to the Regulatory Test. It agreed the creation of a new Australian Energy Market Commission (AEMC) with a last resort planning power to direct that inter-connection projects be subjected to the new Regulatory Test, and a new Australian Energy

The NSW Government, with a direct financial interest, was particularly interventionist. In 1999 it placed the regulatory test on NEMMCO's issues register, meaning that the NEM could not commence until the issue was resolved to NSW's satisfaction. In 2001 a telephone call from the NSW Minister's consultant adviser sought to put pressure on NEMMCO.[13] In 2002 the NSW Minister submitted evidence to the Tribunal. In 2003 the NSW Government, along with the SA Government and TransGrid, filed an appeal against the Victoria Supreme Court judgement.

f) **Multiple regulatory jurisdictions**

The experience of SNI illustrates how three different regulatory agencies in the appeal chain approached regulated transmission in different ways. In two out of three cases the approach was clearly inadequate.

The National Market Management Company NEMMCO was the first quasi-regulatory agency in the process. In December 2001 it accepted that a revised version of SNI passed the Regulatory Test. This required that the project maximise the net present value of total benefits to all who produce, distribute and consume electricity in the National Electricity Market. Appeal to the National Electricity Tribunal revealed that SNI passed the Test on the basis of modelling showing SNI with a discounted present cost of $98.4m and discounted present benefits of $264.5m, hence a net present benefit of $166.1m. The calculations assumed that Murraylink would be in operation.[14]

However, later examination in front of the Tribunal (by which time Murraylink had been built) revealed that SNI could be considered as two separate components. One component, which became known as 'Unbundled SNI', comprised various reinforcements of the transmission system in NSW; this had a cost of $41.2m and benefits of $351.4m, hence a net benefit of $310.2m. The other component was the interconnector part of SNI, which had a cost of $57.2m and *negative* benefits of $86.9m, hence a net cost of $144.1m. The reason for these negative benefits was never explored.

Regulator (AER) to perform all national energy market regulation functions. It proposed to abolish the National Electricity Tribunal.

[13] "It is also alleged that, in the course of that conversation, Mr Price [the adviser] told Mr George or Mr Bones [of NEMMCO] that if NEMMCO did not make a determination that in its opinion the proposal [SNI] was justified, there was a possibility that NSW might withdraw from the NEM. There is some dispute about what was actually said in this conversation. The Tribunal accepts that Mr Price made a telephone call and insisted that a decision by NEMMCO be made quickly and that the Minister wanted a decision which favoured TransGrid's application." National Electricity Tribunal, In the matter of an application of Review of a NEMMCO determination on the SNI interconnector dated 6 December 2001, Majority Decision, pp 41-2.

[14] The precise numbers depended on the assumptions and scenarios used. The results presented here are for the Base Case using what TransGrid's consultants IES called Realistic Bidding Scenario 2 which IES considered "the most realistic of the three bidding scenarios used in the modelling".

The evidence now suggested that a duplicate interconnector did not have a positive net value. It was also apparent that TransGrid's various earlier modifications to SNI to include more reinforcement works in NSW had swung the value of the total bundle from negative to positive. The fact that the distinction between the uneconomic interconnector SNI and the economic network reinforcement (Unbundled SNI) had escaped NEMMCO suggests that this quasi-regulator had not carried out a particularly probing economic analysis. The Minority Report to the Tribunal (see below) suggested that NEMMCO should have sought expert economic advice. The inability of the Tribunal as a body to realise what was happening, and to make or require an adequate economic appraisal of the regulated interconnector proposal, was a further serious defect in the regulatory framework.

The obvious conclusion at this stage was that TransGrid should proceed with the network reinforcement (Unbundled SNI) and abandon what was now an uneconomic duplicate interconnector. The focus should have been on the design, pricing and financing of the system reinforcement, the provision in the most economic way of any necessary protection against risk to the incumbent transmission system, and the appraisal of any implications for competition.

However, TransGrid resisted. It argued that Unbundled SNI was not commercially viable because it did not have a 'proponent'. Moreover, such an investment would leave TransGrid subject to an unacceptable risk of asset stranding because Murraylink had market power and would have the ability and incentive to restrict the level of output over its own interconnector. This in turn would reduce the level of flow across Unbundled SNI, and the ACCC might therefore write down TransGrid's assets as underutilised.

In reply, Murraylink argued that it did not have this market power, that the risk to TransGrid was negligible, that Murraylink was willing to be a proponent of Unbundled SNI, and that any risk could more economically be dealt with by a commercial arrangement between TransGrid and Murraylink than by constructing the uneconomic duplicate interconnector SNI.

The Minority member of the Tribunal (with stated expertise in engineering, economics and sociology) held that neither NEMMCO nor the Tribunal had carried out a full and proper cost benefit analysis as required by the regulatory test. The whole process was "fundamentally flawed". Consequently SNI was not justified. The two Majority members (both lawyers) accepted TransGrid's arguments. They held that its apprehension of risk was "real and not unreasonable", and that Unbundled SNI was not commercially feasible hence was not an alternative to full SNI. So full SNI maximised the net value of benefits and therefore passed the regulatory test. In their view, there was no need to have regard to "general cost benefit principles at large".

On appeal, the Victoria Supreme Court rejected most of Murraylink's complaints about the Tribunal's failure to follow due process. It said that the Majority had adequate evidence on which to take a view about the cost benefit analysis provided, and was entitled to accept it. However, it found that the Tribunal had erred in law by rejecting Unbundled SNI simply on the basis that TransGrid refused to be a proponent of it, and that the Tribunal had failed to explain why there was a significant risk of stranding if TransGrid constructed Unbundled SNI. TransGrid's consultants had submitted evidence that if Murraylink was uncontracted there could be a restriction of 0.013312% of flow on Unbundled SNI (i.e. on the reinforced part of the transmission network). The judge opined that "My own uninformed view is that it is difficult to imagine that a restriction of 0.013312%, or even a figure of 100 times that amount, could ever be regarded as more than negligible". The Majority had failed to establish "whether a risk of restriction of that order of magnitude would so much deter an objective operator, acting rationally according to the economic criteria prescribed by the regulatory test, as to refuse to construct Unbundled SNI if [full] SNI were not approved."

When Murraylink applied for transfer to regulated status, the competition regulator ACCC did not insist that alternative projects have a proponent. But neither did it address all the concerns of the Minority Report about the previous inadequate analysis.[15] The ACCC came out with quite different figures than TransGrid/NEMMCO. Amongst other things, in order to compare Murraylink against alternative projects, it re-evaluated the cost of the interconnector component of SNI[16]. As noted earlier, it assessed the cost of this alternative at $245m; this was in excess of the top end of what it considered a credible range of benefits of an interconnector ($170m - $220m). This compares to TransGrid's consultants' calculated cost of $57.2m and benefit of minus $86.9m that were used in the NEMMCO and Tribunal proceedings. The main reasons for the higher cost were an allowance for undergrounding about 30km of line for environmental reasons and the inclusion of other costs previously omitted e.g. for interest during construction and contingencies. The discrepancy in the modelling costs and benefits again casts doubt on the adequacy of NEMMCO's earlier analysis, but also indicates the sensitivity of regulatory modelling results to the assumptions made.

g) Regulatory resources and reliance on regulated firms

NEMMCO's initial appraisal of SNI was carried out by its Inter Regional Planning Committee (IRPC) and the latter's consultants ROAM. However, there was much debate as to whether ROAM's modelling was adequate, so TransGrid provided some further analysis by its own consultants IES. It was the IES modelling that provided the basis for NEMMCO's erroneous conclusion (and for the deliberations of the Tribunal and the Supreme Court).

In 2002 Murraylink applied for regulated status. The ACCC was required to calculate the benefit of an interconnector. It did not make its own calculations

[15] The ACCC seems to have accepted broadly the same framework and approach as NEMMCO. It did not mention, or make adjustments to meet, two of the Minority's main concerns, related to unequal capital expenditures or to the comparability of early more certain costs and later uncertain benefits.

[16] Actually, this was a somewhat shorter interconnector, comparable in length to Murraylink and excluding the section of SNI lying entirely within SA.

from scratch: with two small modifications, the ACCC accepted the calculations of Murraylink's consultants. It was able to assess the costing of more alternative projects than NEMMCO did because Murraylink provided more alternative costings to assess.

Table 1	**Gross market benefits of the economic project ($m)**
Energy savings from enabling less expensive generation	77.0
Deferred merchant entry (capital)	49.0
Deferred merchant entry (O&M)	5.4
Reliability (reductions in unserved energy, with VoLL = $10,000/MWh)	62.0
Deferred transmission reinforcement in Riverland area	22.0
Ditto (O&M)	1.9
Total	**$218m**

Table 1 shows the ACCC's main calculation (called Alternative 3). The first three items, totalling about $131m and accounting for about 60% of the total benefits, could presumably be captured by a market investment. They would be associated with an annual revenue of about $11m. Prospective trading based on forward market curves suggested an income (and hence benefits) of about half that. But this comparison was not made. The last three items, totalling about $86m and accounting for about 40% of the total benefits, referred to magnitudes that were not recoverable or testable in the market.

These calculations to assess regulatory transmission contrast with those that would be made to assess merchant transmission from a commercial perspective. The ability (or otherwise) to assess the economic viability of projects ex ante, and to check on performance ex post, and the incentive (or otherwise) to do these things, are systematically different. In a comparative analysis, this should be a significant factor in considering the pros and cons of each approach.[17]

This concludes discussion of the two regulated interconnectors in Australia. In sum, the regulated interconnector SNI in NSW was characterised by all of the conjectured regulatory imperfections, and QNI in Queensland by several of them.

6. Coordination and transactions costs

J&T discuss the problems caused by strategic behaviour. One concern is that network expansions are likely to be lumpy. Building and operating a transmission line will narrow the pre-construction differentials in prices so that the remaining value that can be secured by construction understates the total value of the line. There is an under-incentive for a merchant investor to build the line.

[17] Cf Coase (1946) on marginal cost pricing: "Neither Hotelling nor Learner nor Meade give, in my view, sufficient weight to the stimulus to correct forecasting, which comes from having a subsequent market test of whether consumers are willing to pay the total cost of the product. Nor do they recognize the importance of the aid which the results of this market test give in enabling more accurate forecasts to be made in the future." (p 84)

But is it not possible for the exporting generators and the importing customers, who both benefit from these narrowed price differentials, to support construction of the line? Similarly with the concern that a socially more valuable merchant line would be pre-empted by a less valuable investment in generation: why would those who would lose out from this investment just sit back and let it happen?

Another concern is gaming between complementary merchant investments. J&T give an example of two complementary interconnector projects, one from the North to the Middle and one from the Middle to the South. The profitability of each depends critically upon the capacity of the other, since the one with the lower capacity receives all the congestion rent. Hence, they say, neither interconnector dares to move first.

But why do the two interconnectors fail to resolve this issue before construction begins? Or why does one merchant interconnector not build the whole line? It is said that "While this pair is really a single investment from an economic viewpoint, the investments may be undertaken by different entities for technological reasons [different expertise] or other reasons [e.g. separate ownership of rights of way]." (p. 250) Does the concept of a consortium not exist in this world?

J&T reply as follows. "It is sometimes argued that the problems created by lumpy investments can be resolved through negotiations between the various market participants who will benefit from the investment; that is, that the 'Coase theorem' applies. There are many reasons … to believe that negotiations among the affected market participants is unlikely to solve the problems". These reasons are: the costs of transacting especially when the number of stakeholders is large; asymmetric information so that participants may end up being too greedy resulting in bargaining breakdown; absence of future players whose interests are not taken into account; non-excludability of winners and free-riding; and holdup of potential losers.

All these failures are theoretically possible, but are they common in practice? Coase himself has argued not.[18] In their earlier discussion paper, J&T refer to a piece of empirical evidence on this point. "Mechanisms designed to aggregate stakeholder preferences to make choices about major transmission investments have not been particularly successful." (Joskow and Tirole 2003 p 51) They cite Chisari et al (2001) for a discussion of experience in Argentina (a reference that remains in the published paper). The next section examines this experience.

[18] On the 'greedy' point, and in answer to Samuelson's assertion that bargaining would not necessarily end up on the contract curve, he comments "[w]e observe that raw materials, machinery, land, and buildings are bought and sold … We do not usually seem to let the problem of the division of the gain stand in the way of making an agreement. Nor is this surprising. Those who find it impossible to conclude agreements will find that they neither buy nor sell and consequently will usually have no income. Traits which lead to such an outcome have little survival value…." Coase (1988) p 162

7. Coordination and transactions costs: evidence from Argentina

Argentina provides a good opportunity to compare regulated and merchant transmission - in the latter case what might now be called ‘private initiative’ transmission. Until privatisation and restructuring in 1992, transmission was provided by state-owned companies subject to ‘regulation’ by the government. In terms of the regulatory imperfections identified above, the regime was characterised above all by interest group capture and political influence. This manifested itself in excessive operating costs and capital investment, with prices held down to combat inflation. Inter alia, long and expensive transmission lines were repeatedly constructed without economic justification, and their utilisation rates were very low. (Littlechild and Skerk 2008a)

Reform was designed to address these problems in a radical way. The industry was privatised. To prevent regulatory capture, all major transmission (500kV) and sub-transmission (132kV) investment was required to be on what we might now call a private initiative or merchant basis. Market participants who were beneficiaries, rather than the transmission company or the regulator, had to propose, vote for and pay for all major expansions. Approved expansions were then put out to competitive tender to build and operate. This was known as the Public Contest method.

Argentine experience with a ‘beneficiary pays’ approach is of particular significance today. Variants of this approach have recently been adopted by New York ISO[19] and by FERC itself in its Order 1000 (FERC 2011b).

The question of interest here is whether this merchant basis of transmission was subject to the potential imperfections identified by J&T. In particular, was it vulnerable to the lack of coordination and transaction cost weaknesses?

Soon after the new policy was implemented, a Fourth Line from the gas-producing area of Comahue to the capital Buenos Aires was proposed but rejected by a majority of market participants. This line was allegedly much-needed, and had been widely canvassed under the previous regime. The rejection was perceived as evidence that the Public Contest method did not and could not work. It seemed that transactions costs outweighed the advantages of cooperation between market participants. This was the conclusion drawn from the cited paper of Chisari et al (2001).

Subsequent and more detailed research has shown that the Fourth Line was expensive, premature and uneconomic. (Littlechild and Skerk 2008b) Delaying its construction was evidence that the Public Contest method did work, not that it didn’t work. In the short term, the participants agreed instead to expand

[19] See FERC (2008) for the Order accepting NYISO’s filing, NYISO (2010a) especially s 2.2 giving a summary of the process, NYISO (2010b) especially ss 31.3 and 31.4 on cost allocation and s 31.4.3.6 on beneficiary voting provisions. I am grateful to Rana Mukerji and John Buechler of NYISO for these references. See also Hogan (2011) for discussion of cost allocation principles and possible calculations.

capacity by installing capacitors, at a fraction of the cost of a new line. When conditions later made the Fourth Line attractive, the participants worked together well to design, propose and pay for a line that attracted almost unanimous support and was constructed at a significantly lower cost than envisaged in the initial rejected proposal. Subsequently, it became apparent that it was more economic to transport gas from Comahue to Buenos Aires, and build the power stations there, than to build more long-distance transmission lines.

More generally, the Public Contest method enabled substantial investment in better transmission control systems in Argentina. (Littlechild and Skerk 2008d) Over the period 1993 to 2003 system demand increased by over 50%. During that period transmission line length increased by 20%, mains transformer capacity by 21%, compensators by 27% and substations by 37%, but series capacitors by 105%. This more than doubled transmission capacity limits, more than sufficient to meet the increased demand, and more economically than by building more transmission lines.

The Public Contest method has been used extensively, even after the serious problems associated with the economic crisis of 2001 and subsequent events. As of 2007, 36 proposals had been made, some with variants making a total of 40 proposed major expansions. Of these 40, 35 were accepted and all those were implemented. The four largest Public Contest expansions ranged from \$25m to \$247m. There were also other methods of transmission expansion, and from 1994 to the 2001 crisis the number and value of transmission investments steadily increased. Over this same period, all but 5 of the 163 transmission expansions, accounting for all but \$3m of the \$809m total value, were voluntarily agreed by the users.[20]

The voters for a particular expansion are the beneficiaries of that expansion, as identified by a simulation study carried out by the system operator (CAMMESA) using the so-called Area of Influence method. The beneficiaries/voters for each expansion are also the parties who pay for that expansion, in proportion to their benefits and votes. (Amongst other things, this addresses the problem of free-riding.) The number of voters on each expansion ranged from 1 to 65 with a median of 5. Negotiations between market participants were generally not problematic, even though they included a wide variety of types and sizes of generation plants, distribution companies and large users.

Approved expansions were put out to competitive tender. The number of bidders ranged up to 7, with a mean of 2.4 bids. This was sufficient to generate significant competition. Three quarters of the winning bids were below the minimum acceptable level specified by the parties. Independent contractors (at least 11 different ones) won about three quarters of the contracts. The (revised) tender for the Fourth Line attracted 13 bids or variants. The users increasingly designed

[20] The 5 exceptional cases were minor expansions (under \$2m for the transmission system, under \$1m for the sub-transmission systems), which the transmission companies themselves were responsible for proposing. Typically they were for the benefit of only one or two users. In the absence of agreement by these beneficiaries, the regulatory body ENRE was empowered to authorise investment and determine responsibility for payment.

the tenders in more sophisticated ways to maximise competition, and to enable bidders to focus on those areas where they would be most effective. Thus, tenders for new transformers might be divided into several modules: the provision of the transformer itself, the installation of the transformer plus minor expansions in the substation, equipment for metering and circuit breakers, etc. Competition had a significant effect on costs: the cost of building 500kV transmission lines roughly halved over the first five year period.

It would be fair to say that the mechanism designed to aggregate stakeholder preferences to make choices about major transmission investments in Argentina was remarkably successful. It exhibited none of the five potential imperfections identified above. [21]

8. Network deepening investments in Argentina

J&T suggest that network expansion investments (separate new links) can in principle be made by incumbents or others. However, they say that network deepening investments (physical upgrades of the incumbent's existing network, such as capacitor banks and control equipment) and network maintenance can, as a practical matter, only be implemented efficiently by the owner of the existing lines. How did the Public Contest method address these practical difficulties in Argentina?

Maintenance of transmission networks existing at the time of privatisation remained the responsibility of the incumbent transmission company, and was covered by an RPI-X price control. But both network expansion and network deepening investments were subject to the Public Contest method. As examples of the latter, several expansions did indeed install capacitors and control equipment.

J&T give three reasons for their view. First, adding third-party facilities that are fully integrated with the existing network creates significant incentive problems, especially with heterogeneous transmission facilities. Writing and enforcing appropriate contracts would be difficult. Second, the difficulty of allocating the new capacity of the line between the original owner and the new investors would be a substantial obstacle to an effect third party access policy. In Argentina, these problems did not occur because the expansions are not dedicated to particular users: once installed they effectively become part of the incumbent's system. In principle the winning bidder has to maintain the new equipment, but in practice the maintenance of system deepening investments was usually subcontracted to the incumbent transmission owner.

[21] Unfortunately, the situation changed after the economic crisis. Subsequent governments reintroduced regulated investment in the form of a Federal Transmission Plan. Predictably, this was characterised by the defects of the regulated approach, particularly political influence. In 2006 the Government's estimated cost for implementing this Plan was more than double what the cost would have been under the Public Contest arrangements for merchant transmission. (Littlechild and Skerk 2008c)

The third reason given is that entrants are likely to have less information about existing transmission lines than their owners. In Argentina this issue was recognised and addressed in various ways. The incumbent transmission companies were obliged to indicate which major expansions were necessary in their view, and to provide relevant information. They themselves were responsible for proposing minor expansions. They had a role to ensure that expansions of their systems were properly implemented. They could, if they wished, bid to construct, operate and maintain the agreed expansions. It was in the interests of the network users to familiarise themselves with the state of the transmission network, including by liaising with the incumbent transmission companies, and in practice they did so.

Some concerns were expressed that the Public Contest method might fail to secure investments needed to secure quality and reliability of supply. An investigation by the System Operator did not find clear examples of this. Nonetheless it was decided in 1998 to allow incumbent transmission companies (as well as beneficiaries) to propose certain quality and reliability of supply expansions. They were also allowed to initiate the previous kinds of expansions where this involved adding equipment to their existing facilities (e.g. a new transformer in an existing substation). The transmission companies had to provide additional information to justify these requests, and the proposals still had to be voted on. In the event, transmission companies did propose a series of expansions under this new provision, and the beneficiaries (often distribution companies) did indeed support most of them.

9. Meshed networks in Argentina

Rious (2006) has suggested that particular conditions in Argentina have allowed network investments to be put out to competition, namely that the transmission network is almost radial rather than meshed. He suggests that the Argentine experience may not be directly transposed to meshed networks as in Europe and the US where there are many inter-dependencies.

It is true that the main Argentine transmission network is (or was) largely radial, but this is not the case with the five sub-transmission networks. When the sub-transmission network in Buenos Aires province was privatised, there was a need to consider whether and how the Public Contest method could be adopted and used in a meshed network. The answer is that it could be and has been. (Littlechild and Ponzano 2008)

In view of the interdependencies it was necessary to coordinate the various possible transmission expansions and to agree a long-term Transmission Plan that would reduce the regulatory burden and regulatory uncertainty. In 1999 the three provincial distribution companies and 11 of the largest municipal distributors (cooperatives) formed themselves into the Regional Electricity Forum of Buenos Aires (FREBA). The transmission and sub-transmission companies were made advisory members. Over time other cooperatives joined, and by 2006 the association had 174 members responsible for supplying some 95% of demand in the province. They appointed a technical committee to identify and evaluate transmission investment projects for subsequent voting. They took into account the Reference Guide that the transmission and sub-transmission companies were required to provide with suggested expansions to maintain quality of service over the next 8 years. FREBA and the transmission and sub-transmission companies worked together and generally resolved their differences. FREBA was then able to produce an agreed Ten Year Transmission Expansion Plan. The provincial government approved the collection of a special tariff from final customers to fund this. (The last is an element of the framework comparable to the regulated investment approach.)

It was also necessary to agree how the costs would be shared out among users. The Area of Influence method used to identify beneficiaries did not extend down beyond the 132kV network. It therefore failed to identify as beneficiaries the municipal distributors embedded at 66kV and below. A mechanism was needed for taking account of the views and needs of these users. In addition, the main distribution companies were concerned about free-riding. Accordingly, FREBA proposed a method (Resolution about Contributors) to extend the Area of Influence method.

Experience to date is that transactions costs have not been a problem. The Transmission Plan was unanimously approved, so there has been no need to vote on separate projects. The Plan began to be implemented, but the economic crisis and subsequent government policy on price controls held up the raising of necessary funds. This in turn led to a search for more ingenious ways of financing. The approach provided advantages over a regulated approach. FREBA looked further ahead than the transmission company was required to do. It carried out a more comprehensive analysis that better integrated the distribution networks into the picture. The chosen expansions were more economic, and better attuned to the needs of users, than those that the sub-transmission company had identified. The process led to better relations, trust and understanding among the parties.

10. Evidence from North America

A review of regulated and merchant transmission in the US is beyond the scope of this paper. However, some evidence can be brought to bear on the fourth alleged market failure, namely, the suggestion that transactions costs would result in an inability to address problems associated with coordination and the aggregation of stakeholder preferences, and negotiations between market participants. The presumed inability of transmission providers and users with very diverse interests to resolve these issues is suggested as a drawback of a merchant transmission approach.

Interstate pipelines and transmission companies file rate cases before the Federal Energy Regulatory Commission (FERC). The various different users and other interested parties – distribution companies, generators, retail providers, state public utility commissions, large industrial users, customer representatives, etc - register as intervenors and submit their views and testimony. In practice, however, the cases are typically not litigated and decided upon by FERC. About

90% of these rate cases are settled by the parties themselves. Despite their many different interests, and over a considerable range of participant numbers and company sizes, the parties are almost always able to agree on a range of often contentious issues. In addition, the settlements are frequently characterised by innovations and other mutually agreed features that would not appear in a regulated outcome. (Littlechild 2011)

Such negotiated settlements are not limited to transmission cases at FERC: they are frequently found in electricity and telecommunications cases at certain state commissions such as Florida. (Littlechild 2009a,b) They are now standard practice with oil and gas pipelines before the National Energy Board (NEB) in Canada. (Doucet and Littlechild 2009)

This is not to say that the regulatory framework is irrelevant. Before approving a settlement, the regulatory body has to consider any objections and satisfy itself that it meets the statutory criteria. It may decide to modify the agreement. In negotiating an agreement the parties clearly have an eye to what they think the regulatory body would decide in the event that they are not able to negotiate an agreement. They may find it more difficult to reach agreement if there is not adequate regulatory precedent.

The regulatory commissions take different stances with respect to facilitating settlement. The Florida Public Service Commission seems to leave the parties to negotiate on their own; that indeed was the parties' own preference. In Canada the NEB for several years annually set a generic cost of capital formula that indicated what value the NEB would choose if called upon, thereby seeking to facilitate agreement on potentially the most controversial issue. In the US, FERC actively facilitates the settlement process insofar as its Trial Staff propose a first settlement agreement based on standard cost of service ratemaking, then seek to bring the parties together and reconcile differences.

Thus, transactions costs and other potential difficulties such as conflicting interests have not generally been an obstacle to negotiating a settlement between the provider of transmission services and the users of that facility. And the regulatory framework has facilitated those negotiations in various ways.

11. Conclusions on evidence

Choosing between merchant and regulated transmission is a matter of choosing between imperfect alternatives. The economic literature generally, and the more focused debate on alternative transmission policies, suggest five main factors as potential disadvantages of each mode of delivery. Which factors are most important in practice?

In Australia, the two merchant interconnectors may have suffered from imperfect information but were not characterised by market power or the other four alleged market imperfections. In contrast, the regulated interconnector SNI in NSW was characterised by all of the conjectured regulatory imperfections, and QNI in Queensland by several of them. In Argentina, merchant transmission was made mandatory because of the observed weaknesses of previously-regulated transmission. Contrary to initial impressions, this merchant framework worked well: there were productive negotiations between transmission users that resulted in commissioning needed transmission expansions, of all kinds and sizes, without undue transactions costs. Similarly, in various US and Canadian jurisdictions, transmission companies and their customers often find it possible and indeed advantageous to negotiate settlements rather than leave this to the regulatory commissions to decide. They do this to avoid the time and cost of bureaucratic processes, and because they can achieve outcomes that are better informed and better reflect the preferences of the parties themselves.

In sum, market power, transactions costs and various other conjectured limitations *might* be serious problems for merchant transmission in theory – but in the cases we have examined they were *not* serious in practice. Bureaucratic processes, interest group capture, political influence and regulatory resource limitations *might* be serious problems for regulated transmission in theory – and in the cases we examined they indeed often *were* serious in practice.

Imperfect information is a significant challenge for *both* modes of delivery. The problem is not asymmetric information as usually presented, whereby the regulated company knows what its costs and demands are but does not tell the regulator. Rather, the problem is a lack of coordination between all those parties potentially involved. Those who propose to build new transmission, and those who must approve such building, need to be confident that generators and final users will have sufficient demand in future to warrant the investment. This applies not only to each potential interconnector as a whole but also to each detail such as location, size, timing etc. And similarly, those who propose to build or use new generation need to be confident that the necessary transmission facilities will be in place.

The consequence of a lack of coordination is the likelihood that transmission investments will be uneconomic: too much too soon, or too little too late, or in the wrong place, etc. Such mis-investment will be costly to those market participants that pay the immediate costs, and ultimately to taxpayers and/or customers in general.

12. Implications for policy

There is obviously useful scope for analysis of more recent experience with merchant and regulated transmission, especially in the US and Europe. If the analysis and evidence bear out present findings, they suggest certain directions for policy.

First, given that the predicted and observed limitations of regulation can impact adversely on both regulated and merchant transmission, it is important to create the most fruitful conditions for effective competition and regulation. For example, a well-proved elementary building block is to establish transmission companies in separate ownership rather than as part of a vertically-integrated electricity company. (Léautier and Thelen 2009) Also, private companies are more effectively regulated than state-owned ones.

Second, there is scope to improve the professionalism and independence of relevant regulatory bodies. It might be argued that there have been improvements since some of the early experience described above, but the evidence is not always convincing. [22] This is not to argue for more regulation – there is scope to reduce it, including as explained below - but for more focused regulation with adequate access to the necessary resources.

Third, since regulatory failure appears more pervasive than market failure in the transmission sector, and since merchant transmission – including private initiative schemes that do not depend entirely on revenues from spot price differentials - is viable and efficient in a greater range of circumstances than previously recognized, it is sensible to remove barriers to merchant transmission wherever possible. Depending on the circumstances, regulatory measures may be needed to support this: for example, to establish, monitor and enforce obligations on incumbent transmission companies with respect to the provision of access and information, to require outsourcing or competitive tendering, to require or suggest appropriate bases of cost-sharing, to facilitate auctions or negotiations among market participants, etc.

Fourth, given the fundamental challenge of obtaining and coordinating information about the costs and benefits of transmission investment, a key question is whether merchant or regulated transmission is better able to discover and coordinate the information most relevant to taking and implementing major transmission investment decisions. Which approach is better able to incentivise and coordinate the providers and customers of the potential interconnectors, so as to secure the appropriate investment with the minimum of risk? Which approach is better able to discover the kinds of commitment and incentive and risk sharing mechanisms, on both sides of the market, that will be most appropriate, acceptable and effective in the particular circumstances of each potential interconnector?

The general presumption, based upon several centuries of experience as well as economic analysis, is that markets are better mechanisms for learning, discovery and incentives than are regulatory bodies. This is not to say that there is no role for regulation. Rather, regulation would be better employed establishing a framework within which the market can operate effectively. Specifically, regulation would seek as far as possible to facilitate the development of transmission lines that reflect agreement on size, timing, location and charges, etc, rather than take all these decisions itself.

A central argument of this paper is that transmission investment projects and their costs and benefits are not known and given, certainly not to regulators but not to market participants either. A key task is to search for, discover and indeed

[22] A previous NSW regulator says that the present framework is "very close to broken". (Tom Parry, "Lawyers' picnic drives up the cost of electricity", *The Australian*, June 29, 2011) See also Parry and Duffy (2010), Mountain and Littlechild (2010), Mountain (2011).

create transmission investments that at least increase net benefits. To achieve this, it is necessary to discover or design the incentive-maximising and risk-sharing contractual arrangements most favourable to the successful coordination of such investment. Due regard must be had to the implications for competition and to the possibility of coordination across each region as a whole. But both analysis and experience suggest that competitive, merchant or private initiative approaches are more effective than regulation in the process of discovering and creating mutually advantageous transmission investments. A more effective role for regulation is to assist rather than to replace, prevent or thwart this process.

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