Comparison of Long-Term Contracts and Vertical Integration in Decentralised Electricity Markets†

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Abstract

Decentralised electricity systems require effective price and quantity risk management mechanisms, but the nature of such systems poses particular problems for satisfying those requirements. Among these problems are investment hold-up risks rooted in the competition facing both electricity retailers and large industrial firms. Additional problems include those of load profile, information and bargaining mismatches between generators and customers. Significantly, hold-up risks exist not only between retailers and generators, but also affect (e.g. fuel) suppliers upstream of generators. Contracts are one means of addressing such problems, and represent a particular improvement on spot market trading alone. However, we argue that market contracting in electricity systems is a costly approach to addressing hold-up and related problems, and that internal organisation (i.e. vertical integration) is a more efficient alternative, minimising the overall costs of market contracting and ownership. Not only does integration internalise wholesale market risks and market power costs to the integrated firm, thereby reducing their importance, it also reduces the need for and efficacy of regulation to constrain generator market power. It furthermore thins contract markets, reducing the threat of generator hold-up from competitive retail entry, and otherwise supports generation investment and hence supply security. While the reinstatement or retention of retail franchise areas is one possible solution to the problems of contracting, it is arguably unnecessary if there are other system features (such as transmission constraints) impeding retail entry. This is particularly so in systems involving vertical integration, although even then policy makers are confronted with a trade-off between promoting retail competition and facilitating generation investment and supply security, requiring judgement as to the optimal degree of retail market power. While vertical integration is a more natural and self-sustaining solution to electricity sector problems, it too is only a partial solution, leaving complementary roles for spot and long-term contract markets.

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1 Introduction

Many economists and policy-makers have held the view that electricity sectors should be unbundled and opened to competition, and that in such liberalized markets long-term contracts are necessary to constrain generator market power, elicit competitive entry in retailing, and support new generation investment and hence supply security (Boom & Buehler (2006), Vázquez et al, (2002)). In light of this view, the observation that liberalized markets in several countries are showing low or decreasing levels of long-term contracting, and high or increasing levels of vertical integration, (Thomas (2004), Anderson et al. (2007), Hogan and Meade (2007); Gans and Wolak (2008)) has led to concerns about market performance. In particular, policy-makers are concerned that wholesale and retail competition will decrease, and generation investment and supply security may be under threat (European Commission (2007); Michaels (2006)).

However, problems have emerged with the "traditional" view regarding sector unbundling and competition (Green (2004), Chao et al. (2005, 2008) Finon and Perez (2008)). In particular, excessive competitive entry in retailing may threaten the viability of short- and long-term contracts, and thus threaten—rather than promote—generation investment and supply security. This threat emerges because "excess" entry creates critical hold-up risks between retailers and consumers, which in turn translates into hold-up risks for generators, and ultimately their fuel suppliers and financiers. Ironically, this leads to a conundrum – a liquid contracts market is seen as necessary to elicit retail entry, but risk of too much entry undermines the supply and viability of such contracts.

In this paper, we further elaborate on problems arising in contract markets in electricity systems, identifying multiple possible causes of hold-up as well as other contracting problems that can result in inadequate investment and supply security, and increased threat of market power. Specifically, hold-up risks arise not just from the threat of competitive retail entry, but also due to the competition faced by industrial customers, and other factors such as generator fuel mix and fuel supply security. Additionally, contracting in electricity systems is further complicated by factors such as mismatches in the preferred load profiles of generators and contract counterparties, information asymmetries regarding generator outage rates and fuel security, generator market power, and strategic bargaining. The resulting shortcomings in electricity contract markets suggest they are at best a partial and unsustainable solution to market power, retail competition, investment and supply security issues. Instead we argue they are largely a disequilibrium institution, often arising artificially as an imposed element of electricity liberalisations reflecting initial reform priorities and concerns.

We then present the view that high levels of vertical integration should not be a cause for concern, but rather may represent a more "natural" structure for the electricity sector. Where contracts have failed to emerge or operate as expected, and political priorities have shifted away from constraining generator market power in favour of ensuring supply security, the relative importance of contracts in the scheme of electricity system governance has diminished in favour of increased vertical integration (with both contracting and spot energy markets providing complementary and supporting roles). Such vertical integration is, by contrast, argued to be a more self-sustaining institutional arrangement, and one which better addresses issues of wholesale market power, investment, and supply security. Its endogenous rise – even in electricity systems with relatively liquid contract markets – further suggests it has a natural and important role to play in liberalised electricity systems.

In part these benefits flow from vertical integration being better insulated than long-term contracts from the hold-up risks of excessive retail (or industrial) competition. They also arise from the fundamental changes in generator wholesale market risks and incentives arising when generators have embedded customers. At the same time the existence of such benefits calls into question whether concerns about the potential deterrent effect of vertical integration on competitive retail entry are misplaced. This is not only because long-term contracting can also have the same effect on market power and entry (Newbery (1998), Bushnell et al. (2007)), but also because there is a clear trade-off emerging in liberalised electricity sectors between retail competition and supply security objectives. This trade-off challenges the ongoing priority given in most liberalised electricity systems to further enhance retail competition, and to constraining generator wholesale market power (which is both less important and harder to achieve in integrated systems). While some amount of retail competition is important for consumer protection, at some point additional competition becomes counter-productive, not only for investment and supply security purposes, but also for retail market competitiveness itself.

Following our review of the constraints inherent in contracting and the role of vertical integration, we argue for a variation on the conclusion for policy proposed by authors such as Newbery (2002), Roques (2008) and Chao et al. (2005, 2008), who have argued for the retention or reinstatement of retail franchise monopolies as a means to constrain hold-up risks between retailers and consumers. We argue that such measures are possibly unnecessary provided other electricity system features attenuating retail competition are in place, and probably too great a reversion towards pre-reform arrangements (to consumers' detriment). Instead, if policy responses are required to ensure supply security while also eliciting workable but not excessive retail competition, they should include less focus on generator market power, a greater tolerance of vertical integration, and a reduced emphasis on contracting. These could be complemented with other retail-level innovations – such as enhancing demand side responsiveness for small consumers – which do not exacerbate retail level hold-up risks but alleviate market power concerns by means other than competition.

In the remainder of this paper we first set out our analytical framework, drawing on the transaction cost economics and property rights literatures, and empirical literatures on both contracting and vertical integration (in general but also specifically for electricity sectors). We stress the importance of contracts in addressing hold-up problems, but also the circumstances in which ownership (specifically, vertical integration) is a preferable approach. These circumstances involve optimally assigning firm (whether generator or retailer) ownership to the party enjoying the lowest overall costs of contracting and internal organisation.

Section 3 discusses the expectations and experience of contracting in decentralised (liberalised) electricity systems. The particular problems confronting contracting in electricity systems are examined, and the shortcomings of contracting given those problems are highlighted. Section 4 then sets out the ways in which vertical integration better addresses those electricity system problems than does contracting. While vertical integration is argued to be a more natural and self-sustaining primary approach to addressing electricity sector problems such as risk management, securing investment and addressing generator market power, it is not without its limitations. Some of these are examined, and it is argued that both spot and long-term market contracting are natural complements to vertical integration. Finally, in section 5 we conclude with a discussion of the resulting policy implications.

2 Analytical Framework

In this section we present a framework for reviewing the roles of long-term contracts and vertical integration. We largely draw from the transaction costs theory of governance structure, under which a firm's choice of governance mechanism (such as contracting or vertically integrating) is based on the costs that firm faces in attempting to transact in the market (Coase (1937), Williamson (1985)). We also discuss the importance of ownership costs (following, in particular, Hansmann (1996)) which interact with transaction costs to influence governance choice. We conclude the section with a brief discussion of how our general framework applies more specifically to electricity systems, looking in particular at the occurrence of vertical integration in such systems and what this means in terms of market outcomes. This leads in to our more detailed exploration of electricity contracts and vertical integration in Sections 3 and 4.

2.1 A Spectrum of Governance Choices

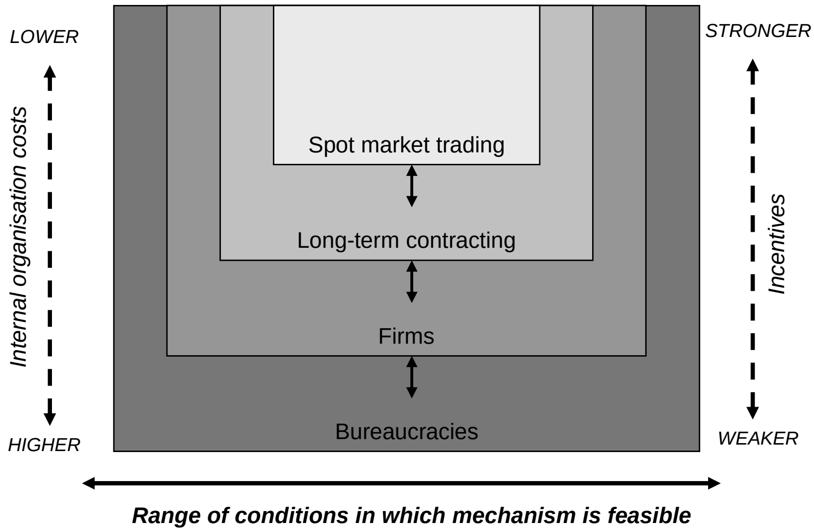
Sector transactions may be governed under a spectrum of different (explicit or implicit) contracting mechanisms, ranging from markets to firms to bureaucracies (Williamson (1985)). Because each mechanism provides a different level of incentives and involves different costs, each will be "ideal" under a different set of conditions (related to transaction costs, organisational costs, incentives, and ownership). However, experience and theory suggest that a given sector will seldom favour a single ideal governance mechanism; rather, different sector needs and characteristics give rise to complementary combinations of governance mechanisms.

2.1.1 From Markets to Bureaucracies: Moving Along the Spectrum

Williamson (1985, p. 87) starts from the premise that "in the beginning there were markets" and hence that "Only as market-mediated contracts break down are the transactions in question removed from markets and organised internally." This suggests a hierarchy among the alternative governance forms (see *Figure 1*), with markets being presumed the most desirable form in situations in which they are feasible, then private internal organisation (firms), then bureaucracies (which may be thought of as "political markets").

However, as *Figure 1* indicates, markets are feasible in a narrower range of conditions than firms and bureaucracies are. As the nature of the transaction changes, so too does the ideal form of governance, leading to a shift "down" the hierarchy (e.g. from spot markets to long term contracts) or re-balancing of the mix of governance mechanisms used (e.g. some spot contracts may remain, but the majority of trading may be through long-term contracts).

Figure 1: Different governance mechanisms are feasible in different ranges of conditions



Which governance mechanism is ideal for a given set of transactions depends on two key factors:

- *The size of transaction costs* relative to internal organisation costs. Coase (1937) suggested that transaction costs were *the* deciding factor between market-organised (spot and long-term contracts) and internally-organised (firm based) transactions. Relevant transaction costs include search and price discovery costs, as well as market-distorting taxes or regulation. Transaction costs tend to increase with increasing transaction frequency, decreasing numbers of potential trading partners (often due to increasing asset specificity), and increasing temporal specificity (leading to a risk of hold-up); and
- *The desirability of strong incentives.* The desirability of strong incentives depends on the extent of imbalances (asymmetries) between the transacting parties in respect of market power, incentives to behave opportunistically, information, endowments and risk preferences. As *Figure 1* indicates, incentives weaken as transactions shift away from markets and towards bureaucracies.

From Spot Markets to Longer-term Contracts

In situations with low transaction costs, symmetric information, and limited market power or risk of opportunistic behaviour, spot markets are both a feasible and desirable mechanism for governing exchange – they provide strong incentives and have low organisational costs.

As transaction costs increase, and the desirability of strong incentives decreases, other forms of governance become more feasible and desirable. This may involve a shift from spot type contracts to longer term contracts. For example, Adler et al. (1998) note different contract types (such as fixed-fee or cost-plus) are preferred in different transaction cost conditions. These conditions include contract knowledge ("the contact hours the seller and buyer require to learn each other's requirements to complete the transaction") and contract impediments ("the inability of the buyer to adequately state contractual terms to the seller, ultimately lengthening contract duration, and changing the technical design").[2] Fixed-price, spot-type contracts are only feasible when contract impediments are low; as it becomes more difficult to state performance requirements in full, longer-term, more incentivised contracts play a greater role.

From Contracts to Firms

As transaction costs increase further, the shift may be from contracts to firms. For example, as noted by Coase (1937), in repeated market-based transactions either repeated contracting (such as through the repeated use of spot markets) or long-term contracts are required. Such contracts need to be specific about the rights and obligations of the contracting parties in all relevant states of nature. Achieving such specificity – or contractual completeness – becomes increasingly difficult as asymmetric information, uncertainty, bounded rationality, and transaction costs increase. In such situations, internalising transactions with a firm may be a more desirable form of governance. When contracts are internalised they can be less prescriptive and comprehensive. Furthermore, instead of relying on external contract monitoring and enforcement mechanisms, the firm can devise internal mechanisms and tailor these to the particular nature of the transactions.

Authors such as Williamson (1985) extend Coase's theory further by highlighting the importance of asset specificity in motivating internal organisation (through firms or vertical integration) over market-based transacting. When parties to a contract make long-lived relationship-specific investments, they are then exposed to the risk of *ex post* opportunistic behaviour in which either or both of them seek to extract rents from the other by renegotiating or reneging on (i.e. "holding-up") the contract once the relationship-specific investments have been made (i.e. sunk). This exposure arises because these investments cannot be costlessly redeployed in the event of hold-up. Such behaviour, if anticipated by the contracting parties, results in less contracting and investment than the parties might otherwise jointly prefer, unless they can otherwise credibly commit to each other not to act opportunistically. Where such commitment mechanisms are too costly to institute, ownership of one party by the other can be a viable alternative – whence the rationale for either backwards or upstream vertical integration (one party owning its supplier) or forwards or downstream integration (one party owning its customers).

From Firms to Bureaucracies

Finally, at the far end of the spectrum from markets, where transaction costs are particularly high, and high-powered incentives would exacerbate problems such as market power, asymmetric information and opportunism, bureaucracy can be the optimal governance form – it provides weaker incentives and, although it has higher internal organisation costs, these would be offset by the benefits of avoided transaction costs.

[2] The authors take their findings from a review of contract data from the United States Air Force. Unlike some other sectors, where contractual information may be unavailable or proprietary—as, indeed is currently the case with most electricity contracts in New Zealand—the authors find the Air Force equipment manufacturing and purchasing records to be fairly complete.

Multiple Forms of Governance

Importantly, different forms of governance may not be mutually exclusive – in other words, in some circumstance firms may not choose a single "optimal" governance form based on their overall transaction costs, but rather use multiple forms to address different market needs. For example, Wolak (1996) notes that electric utilities in the United States use both spot and long-term contracts, simultaneously, to purchase the same product (coal, although the situation is similar for gas and oil purchases, and also occurs in the water sector with bulk water purchases). From his analysis of price and demand data, Wolak (1996) concludes that, although long-term contracts are good for ensuring supply stability for the majority of demand, "for the most part, plants use spot market transactions to satisfy residual demands due to unforeseen events and are willing to pay even higher prices for and purchase from even more distant suppliers the larger is this residual demand" (p. 164). Thus, spot contracts play an important role in *complementing* long-term contracts; a role that may also be played in relation to vertical integration, which shares many structural similarities with long-term contracts.

2.1.2 The Boundary Between Contracts and Firms

The particular governance "boundary" that we are interested in for this paper is that between market-based contracting and vertical integration of otherwise contracting partners within a firm. Hansmann (1996) provides a useful model for thinking about how market participants decide which side of the boundary to fall on. He acknowledges that long-term contracts have their virtues – in particular, they can be an effective remedy to many of the problems related to reliance on spot transactions. Long-term contracts may be designed to avoid hold-up problems (such as when an investor wants to avoid sinking costs in a long-lived asset only to be held up by its counter-party upon the renewal of a short-term supply contract). Long-term contracts can also be used to allocate specific risks – for example, determining to what extent a supplier is liable for interruptions to supply. Finally, long-term contracts may be used to mitigate adverse selection risks – for example, requiring performance warranties where product or service quality becomes apparent over time.

However, Hansmann (1996) also notes that long-term contracts have costs which, if high enough, will favour vertical integration. He points out that severe problems of contractual imperfection or incompleteness can arise from a combination of asset specificity (i.e. physical and human capital with large sunk costs), temporal specificity (i.e. the requirement that certain products and services be provided at specific times), and high contracting costs. These combined factors explain, for example, why farmer-ownership of dairy processors (i.e. downstream vertical integration) often dominates over investor-owned processors. Product perishability exposes farmers to daily hold-up problems, and homogeneity of interest lowers costs of collective decision making. Similarly, customer-owned rural electricity distribution cooperatives, and upstream generation and transmission cooperatives in the US – both examples of upstream vertical integration – can be explained in terms of low collective decision making costs (homogeneity of interests) as well as risk of market power abuse by investor-owned firms (or the absence of such firms where investment is not profitable).

Findings in other sectors confirm this preference for vertical integration when contracting costs are high and contracts are necessarily incomplete. For example, from a review of over 100 empirical studies across a range of sectors,[3] Lafontaine and Slade (2007) find substantial evidence that the following factors significantly increase the presence of backwards vertical integration (that is, influence firms to "make" rather than to "buy"):

- Greater specificity of physical capital and of human capital;
- More dedicated and more complex assets;
- Greater site specificity (in other words, when co-location is more important);
- Greater temporal specificity (in other words, when there is a greater need to integrate transactions, and have a timely supply, to avoid "hold-ups"); and
- Greater uncertainty about demand.[4]

Similarly, Lajili et al. (2007) conclude from their review of over 50 studies that "empirical findings generally corroborate the importance of various forms of relationship-specific investments for explaining and predicting vertical integration" (p. 15). In particular, their review confirms the significance of transaction frequency, numbers of trading partners, asset specificity, certainty of asset life span, and demand uncertainty in the decision to vertically integrate. They note that several of these factors are interrelated: for example, higher levels of asset specificity limit the number of trading partners, making it more likely that the firm will be inclined to vertically integrate.

Ownership Costs Combine with Transaction Costs to Affect Governance Decisions

Hansmann (1996) extends the discussion of the importance of transaction costs in vertical integration decisions to include a discussion of property rights or ownership costs.[5] Under his scheme, ownership optimally falls to the class of firm patrons (i.e. suppliers, customers, workers, capital providers) enjoying the lowest *combined* costs of market contracting and ownership (i.e. internal organisation). For example, if market contracting costs should happen to be highest for a patron class that also has the lowest costs of ownership, then clearly they are the best patrons to own the organisation.

Market contracting costs include the costs of hold-up risks, market power (e.g. bargaining imbalance in the contacting process), asymmetric information and strategic bargaining (where a better informed party to the contract negotiates better terms at the other's expense), problems in credibly signalling patron preferences and the costs of long-term contracting. To this can be added regulatory risk (see also Helm (1994)[6]).

3 Including naval shipbuilding, engineering, automobile manufacturing, apparel, chemical products, coal and electricity, trucking, and others.

4 Interestingly, Klein and Murphy (1997) propose that vertical integration is more likely in conditions of uncertainty not because of asset specificity-related transaction costs, but because uncertainty makes it more likely that an explicitly specified performance contract "will move outside the self-enforcing range" (p. 420).

5 Hart (1995) and Whinston (2003) go further, suggesting that a property rights model may be a better explanatory approach than transaction costs. The property rights model argues that asset ownership changes investment incentives because the property rights confer the right to make decisions on asset use if contingencies arise that were not specified for in a contract, and the likely outcomes of ex post bargaining will affect ex ante investment. Despite the potential for property rights theory as an explanatory tool, Lafontaine and Slade (2007) observe that there has been little testing of property rights theories of integration. From what testing has been, they conclude that property rights theory appears best able to predict manufacturer-retailer or franchisor-franchisee relationships, whereas it has less support from studies of supplier-manufacturer relationships (which strongly support a transaction costs theory of integration).

6 Helm (1994) notes that regulators generally review and approve utility costs every three to five years. This period is very short compared with investments in major utility assets, which are typically made over a much longer term.

Ownership costs, by contrast, include the costs of internal governance mechanisms (i.e. the classic agency costs of Jensen and Meckling (1976), Fama and Jensen (1983)), the costs of collective decision making, and the costs of risk bearing (which relates to patrons' diversification and access to capital)).

Under Hansmann's (1996) scheme, vertical integration is a mechanism for internalising a range of risks and costs to the firm. By dispensing with the contracting requirements of market-based transactions there are savings in terms of both direct contracting costs and the costs arising from imperfect contracting. Incentives for opportunism are mitigated (though perhaps replaced to some extent by agency costs of internal governance), since the costs of that opportunism are borne within the same organisation. Exposure to volatile market prices is removed (or at least substantially reduced), since price changes that disadvantage one part of the firm advantage another. Information asymmetries give rise to agency costs of internal governance, but once again the costs of asymmetric information and strategic bargaining are internalised to the firm and hence should be lower overall than when they are borne by only one party to a contract. Although opportunities for double marginalisation may arise through integration, exercise of market power may now become moot, since monopoly pricing in one part of the firm directly increases costs in another part, leaving total firm profit unchanged (Hogan and Meade (2007)). By removing market variables from the firm's objective function (or simply from view), vertical integration also reduces the risk of (and scope for) adverse regulatory interventions such as price regulation. Integration can also remove the need for otherwise beneficial regulation, since the integrated firm internalises the costs that such regulation would seek to mitigate. It is only when the costs of ownership exceed these combined cost savings that market contracting should remain preferred to vertical integration.

2.2 Governance Choices for Electricity Systems

We now turn to governance mechanisms in electricity systems, focusing in particular on where vertical integration has taken precedence over contracting. We first outline the types of vertical integration that might be expected under our analytical framework, then briefly review actual vertical integration and contracting that has occurred in various electricity markets. Finally, we summarise findings from the literature on what the impacts of vertical integration have been. Despite fears that vertical integration would enable firms to exercise market power, preventing entry and pushing up prices, evidence suggests vertical integration may in fact have had a positive effect on market competitiveness and consumer welfare, as well as investment and hence security of supply.

Although investors seek long-term contracts to mitigate the risk of their long-term investments, regulators generally have discretion to make decisions that conflict with the contractual terms—for example, approving a lower amount of expenditure than envisaged in the contract. Vertical integration (particularly forwards) may be the best solution to such regulatory risk—for example, Helm (p. 20) notes, "Oil companies have backed their refinery assets with petrol retailing outlets. Breweries have invested in pubs. In the utilities, franchises have been established by statute to assure a contracting base."

2.2.1 Expected Vertical Integration in Electricity Markets

In considering the use of vertical integration instead of contracting in decentralised electricity markets, two variants might be expected. The first involves downstream vertical integration by generators into activities such as retailing, or less commonly into large industrial activities. It might also involve downstream integration by fuel suppliers into generation. The second variant involves upstream integration between retailers or large industrial customers (whether alone or in concert with others) into generation. Under Hansmann's (1996) scheme whether such upstream or downstream integration is to be preferred depends on the balance of ownership and market contracting costs faced by suppliers and customers. Downstream integration by generators creates agency costs, but likely involves low costs of collective decision making and risk bearing. Upstream integration by numerous small customers possibly involves prohibitive costs of collective decision making, especially where such customers have heterogeneous preferences. Conversely, upstream integration by large customers or retailers (who aggregate small customers) either involves fewer such collective decision making costs, or internalises them to the firm.

Whether or not these relative costs are determinative as between upstream or downstream integration depends on the costs of market contracting faced by each patron class. Multiple small customers may face risks of generator market power, but if electricity is a small part of their total expenditure then the costs of contracting with generators will likely bias them to do so via retailers (for whom the costs of market power are more concentrated, and contracting costs are lower). When large electricity customers are at risk of hold-up by generators (for example, through unfavourable contract negotiation in the presence of generator market power or asymmetric information regarding plant or fuel availability) then they may prefer upstream integration despite having relatively low contracting costs (as compared with small customers). Indeed, this is even more so if their ownership costs are lower still.

2.2.2 Observed Vertical Integration in Electricity Markets

The theoretical expectations outlined above have been borne out to different extents in different markets. The New Zealand and Spanish markets, among others, are notable for their high degrees of vertical integration between generators and retailers. In New Zealand, generation is dominated by five integrated companies ("gen-tailers"), accounting for around 91% of generation capacity and 97% of total demand (Hogan and Meade (2007)). Similarly, in Spain, four integrated firms account for 93% of generation and 97% of retail sales (Kuhn and Machado (2004)). A further notable example is the PJM system in the US, where the six largest retailers also retained their generation assets at restructuring, accounting for roughly 70% of the retail market and 90% of generation capacity (Bushnell, Mansur & Saravia (2007)).

Although such a high degree of vertical integration has been characteristic of, for example, the PJM and New Zealand markets since restructuring in the 1990s, other markets began with a fully disaggregated sector (post-restructuring) that has subsequently moved towards greater integration (for a comparison of the sizes and characteristics of these different markets, see *Appendix A*). For example, the UK market had three major generation companies and 22 retailers in 1990, but now features substantial vertical integration: in 2005, six major retailers, collectively owning approximately 50% of the country's generation assets, supplied 99% of electricity customers (International Energy Agency (2005)). Similarly, Australia began with complete separation of generation and retailing in the mid-1990s, but now vertical integration appears to be becoming a "dominant strategy" both in Victoria (where the first retailer purchases of generation assets occurred) and throughout the National Electricity Market (NEM) (Simhauser (2007)). As of 2007, four major retail businesses, with a combined 75% of market share, had ownership stakes in approximately 73 percent of generation assets (NERA (2007)).

In both the UK and Australia, mergers and acquisitions between retailers and generators were not explicitly prohibited by new regulations, and have generally been approved by competition authorities (although initially the Loy Yang merger in Australia was opposed by the ACCC on competition grounds, which decision was later overruled by the Federal Court – Gans and Wolak (2008)). In contrast, in markets such as California, regulation brought in during reforms required complete separation, excluding the possibility of any vertical integration (or long-term contracts).

More recently, the observation that liberalised markets in several countries are showing low or decreasing levels of contracting, and high or increasing levels of vertical integration, (Thomas (2004), Anderson et al. (2007), Gans & Wolak (2008)) has led to concerns about market performance. In particular, policy-makers are concerned that wholesale and retail competition will decrease, and generation investment and supply security may be under threat (European Commission (2007), Michaels (2006)). However, as we discuss below, fears that vertical integration will lead to the exercise of market power and welfare losses appear to be unfounded.

2.2.3 Impacts of Vertical Integration in Electricity Markets

In line with view that mergers within markets may have an anti-competitive effect, some economists have proposed that vertical integration enables firms to exercise market power (through foreclosure or through other means), resulting in higher retail prices (Micola et al. (2008), Gans (20007)). Similarly, the European Commission (2007) recently observed that vertical integration appears to reduce liquidity in European electricity markets, and may constrain entry.

However, Bushnell et al. (2007) note that although foreclosure is a concern in markets with vertical integration (between generation, retail *and* distribution or transmission),[7] it is seldom a problem in practice due to open access and non-discriminatory pricing requirements for distribution and transmission networks. Mansur (2007) explores the relationship between vertical integration and market power further, reviewing activity in the PJM electricity market before and after restructuring. He finds that restructuring in the PJM market led to an increase in anti-competitive behaviour by vertically-integrated firms that were large net-sellers, but that vertical integration overall had a mitigating effect on market power. He also finds (2008) that the likely welfare impacts of the exercise of market power were relatively small, leading to prices only 3% to 8% above a competitive benchmark.

In fact, evidence suggests that vertical integration may be associated with lower prices than those experienced in a fully unbundled sector. By running simulations based

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[7] Foreclosure is not a significant problem with vertical integration between retail and generation alone, as there is commonly no natural monopoly element in retailing to be used to discriminate against competitors.

on the performance in the three largest and oldest US electricity markets – California, PJM and New England – Bushnell et al. (2007) find that vertical integration may in fact result in the exercise of less market power and contribute to *lower* retail prices than in an unbundled sector, controlling for horizontal market structure. These findings may be explained by the fact that, with vertical separation, retailers lack a "natural hedge" and face potentially extreme wholesale price risk, deterring entry and reducing retail market competition. Hogan and Meade (2007) support these findings of lower retail prices in their model of spot wholesale and retail electricity markets. They find that generators always overstate prices when vertically separated from retailers, although this incentive falls as market share decreases. Conversely, when generators are vertically integrated (with the same retail market share as their respective wholesale market share), they do not overstate their supply curves. They also find that retail prices are higher in a market with vertical separation than in one with full integration.

Vertical integration may also have a positive impact on investment. As Newbery (2002) explains, competing retailers in a vertically separated market tend to prefer short-term over long-term contracts to mitigate their risk of falling wholesale prices. This increases the wholesale price risks to generators, leading to a decrease in investment. In such a situation, generators will have incentives to vertically integrate with retailers (and horizontally integrate with other generators) in a bid to increase prices to more profitable levels. Thus, vertical integration allows both retailers and generators to manage risks (a commonality of interest also noted by Chao et al. (2005) and Meade (2001)), and in doing so also enables increased investment.

In line with these findings, evidence also suggests that de-integration (unbundling) may be harmful in sectors with existing vertical integration. For example, Bushnell et al. (2007) find that if the PJM and New England markets had been forced to fully unbundle (as happened in California) retail prices in those areas would have been significantly higher, as would have production inefficiencies.[8] In a similar vein, Michaels (2006), and Sioshansi and Oren (2007) note that forced divestitures may increase incentives for firms to exercise market power. In a review of empirical studies of gasoline refining and sales, Lafontaine and Slade (2007) find that "divorcement" can lead to cost and price increases and a reduction in service quality. Thus, vertical integration may in fact be better for consumers – a conclusion supported by Cooper et al. (2005) in their review of empirical evidence from a range of industries.

This range of findings on the potentially positive impacts of vertical integration contrasts with the view that vertical integration is a sign of sector weakness, particularly where such integration leads to small and illiquid contracts markets (which have previously been viewed as a key determinant of strong sector performance). We explore this contrast further in the following sections, using the framework presented in this section to first explore the roles that contracts markets can realistically play in the electricity sector, and then to better understand the situations in which vertical integration may be a "natural" and superior alternative – alongside contracting to some degree – for managing risks and supporting investment in electricity systems.

[8] The authors estimate these inefficiencies would have resulted in costs being over 45 percent higher than production costs under vertical arrangements.

3 Contracts in Decentralised Electricity Systems

In this section we explain and elaborate on the problems that occur in contracts-based electricity markets, identifying why the "traditional" view of appropriate sector structure may fail to produce desired sector outcomes in practice. Reasons for this failure include hold-up risks, adverse selection risks due to market power and asymmetric information, contract market illiquidity (due to features inherent in both electricity systems and electricity markets), and mismatches between generators and retailers in terms of preferred load profiles and relative risk aversion. Initial conditions are also emphasised, in terms of contracts, vertical integration or excess generating capacity at the commencement of decentralisation.

3.1 Expected Role of Contracts

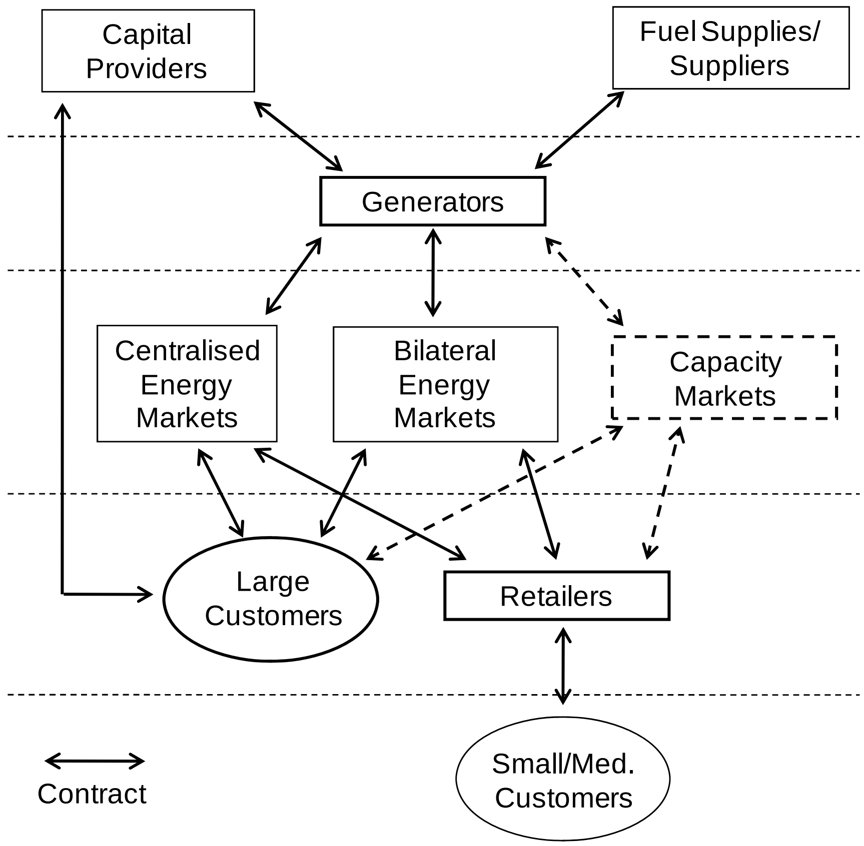
The "textbook" model of electricity sector liberalisation holds that vertical and horizontal integration across all parts of the system – generation, transmission, distribution and retailing – is not a necessary form of organisation. In particular, while transmission and distribution retain "natural monopoly" features that limit their contestability, it is possible to introduce welfare-enhancing competition across generation and retailing. Doing so requires the vertical separation of generation, retailing and the non-competitive network activities, horizontal unbundling of otherwise unnecessarily monopolistic generation, and non-discriminatory access to network assets to facilitate competitive entry of generators and/or retailers. To facilitate transparent and competitive price discovery, some form of wholesale market is required, whether it takes the form of a centralised pool or bilateral trading, energy only spot markets or a range of real time and forward (including day-ahead) energy and capacity markets.

Such changes have been facilitated by reductions in the minimum efficient scale of generation technologies, as well as improved control technologies that enable the coordination of decentralised electricity components to maintain system reliability in the face of electricity's particular requirement for real time balance of supply and demand, given that electricity cannot be economically stored. While the separation of activities that were formerly tightly coordinated involves lost economies of scale and scope, the combination of improved technologies and greater competition between generators and retailers is predicted to provide greater, offsetting gains.

As noted by Chao et al. (2005) and Finon and Perez (2008), the drive towards vertical separation and market-based competition was predicated on two key assumptions. First was that contracts markets, complemented by spot markets, would naturally develop (or could be sustainably imposed) to replace the former vertical integration arrangements, as illustrated in *Figure 2* (overleaf). Second was the assumption that generators would be able to raise capital to fund new investments without the security of cost recovery (whether via cost of service regulation or private utilities in the US, or through consumer franchises and taxpayer guarantees in state-owned systems such as the UK, Australia and New Zealand).

As to the first assumption, of particular importance is contracting between generators and either large customers or energy retailers which aggregate portfolios of smaller customers. Assuming liquid physical and financial markets for such contracts are developed over a suitable range of contract horizons and contract types, then a number of benefits could be expected to flow. Large customers would be able to hedge their electricity price risks through direct purchases of wholesale contracts tailored to match their load profile, and rely on their scale to counter-veil against any market power held by oligopolistic generators. Retailers would be able to reduce their exposure to demand uncertainty by pooling numerous smaller customer loads, and run a portfolio of supply contracts to match the risk characteristics and profile of that pooled load.

Figure 2: Contracting in Stylised Decentralised Electricity Systems



Moreover, a liquid contracts market, supported by institutional changes to ensure retail customer contestability (e.g. switching rules), should enable the competitive entry of retailers, thereby ensuring competitive pressure is placed on retail margins. The ability of entrant generation to trade through a spot market or other contracts markets similarly introduces the prospect of increased competition in wholesale prices. Finally, generators making new investments should be able to secure their investment returns by entering into suitable long-term contracts with one or more parties, which should go some way towards satisfying the second of the key assumptions underlying liberalisation.

3.2 The Experience of Contracting

Experience in many countries has not lived up to the predictions that liberalisation would lead to increased competition in wholesale and retail markets, the emergence of a range of contractual forms to support long-term investment, and better sector outcomes (in terms of generation adequacy and lower prices). Firstly, retail entry has not eventuated as expected, despite entry by start-up independent electricity retailers, diversifying gas retailers, and incumbent electricity retailers from other regions (Defeuilley (2008)). Even at their peak in 1999-2001 the independent retailers were unable to secure more than a 2% market share in the UK, for example, which along with Norway and Sweden was one of the more vibrant retail markets. Such firms proved to be unable to secure adequate physical and financial contracts to hedge their exposure to wholesale electricity prices, and the remaining independent firms have found it necessary to integrate upstream with generation to survive. Conversely, other entrants have been able to continue, in part due to their own vertical or horizontal integration (for example, into electricity from gas, as illustrated by Centrica in the UK, the former gas utility that is now the only major electricity retailer without generation interests).

Similarly, expectations in generation have not been met: investors appear to have become more wary, despite initial post-reform enthusiasm, and long-term contracts have not developed or performed to the satisfaction of project financiers. Joskow (2006) records that significant investment arose in the US when generation was opened to competition. In the 1980s independent power producers were able to project finance new generation (typically gas-fired CCGT) using high debt levels on the strength of supply contracts written with utilities that retained some measure of customer franchise. In the 1990s such project financing of merchant generation continued, but without contracting. Instead, reliance was placed on (at that time) high wholesale prices to finance investments, to the detriment of many entrants when wholesale prices fell and gas prices rose. The resulting bankruptcies and withdrawal of merchant generation in the US – notably California in 2001 – has been reflected in similar experiences in the UK and elsewhere in Europe. While the UK's "dash to gas" in the 1990s resulted in significant new CCGT investment supported by 15 year supply contracts with retailers who retained some measure of retail franchise, failures also resulted there when wholesale prices fell following the 2002 introduction of NETA. Consequently financiers of new generation investments now demand highly creditworthy output contracts as a condition of funding arrangements. Aside from such examples of financial distress Joskow highlights the additional "missing money" problem plaguing many systems – in which average electricity prices – even when capacity mechanism payments are considered – are inadequate to fund new investment. He attributes such problems to features of electricity market design and operation, such as system operator discretions over managing operating reserves, price-inelastic demand, and wholesale price caps.

More in line with predictions, contract markets *have* developed to a significant degree in a number of electricity systems (Chao et al. (2005), Anderson et al. (2006), Finon and Perez (2008)). Among these are the UK and Australia's east coast National Electricity Market (NEM). In both cases generation was unbundled and/or privatised with long-term vesting contracts in place to smooth the transition to competitive markets, providing both price certainty and constraints on remaining generator market power. In the UK this was further reinforced by the radical restructuring of the centralised wholesale "pool" in England and Wales and its replacement with NETA in 2002, relying as it does almost exclusively on bilateral contracting and only a limited centralised real time balancing market. By contrast contract markets developed organically in Scandinavia's NordPool and in Germany, driven by grid companies and utilities respectively.

Where contract markets have developed, however, they have not developed to the extent envisaged. Anderson et al. (2006) report that base load generators in the NEM are 70-80% hedged on average, which compares with 95% in the UK, around 80% in the US' PJM and New Zealand systems, and 73% in New England. Moreover, trading volumes can be substantial – up to 4-5 times physical demand (HMDSG (2005)).

However, Anderson et al. report that most NEM contracts are typically for less than four years duration, mirroring the experience in the US and New Zealand where contract duration is usually no more than three years (Chao et al. (2005), Hansen (2004)). Similarly, low contract durations are reported for the UK, where most trades are for one year only (HMDSG (2005)). Moreover, contract volumes can also be small, with trades in New Zealand representing around just 25% of total demand (Electricity Commission (2008)).

Furthermore, even where contract markets have developed to a significant degree, and more so where they have not (e.g. New Zealand), vertical integration has increasingly arisen. Examples include the UK, Australia, EU and New Zealand. In the NEM, Simhauser (2008) attributes a trend towards vertical integration to a combination of factors, including the initial mix and level of of base load and peaking generation. Like many liberalising systems the NEM began with a surplus of generation capacity. This surplus depressed prices, resulting in falling generation capacity and peaking plant investment. Falling generation in turn reduced the supply of contracts, which combined with a doubling in the regulated wholesale price cap to create a "domino effect" as retailers invested upstream in generation to some degree (especially in peaking and intermediate plant).

In New Zealand vertical integration quickly arose as an unintended consequence of simultaneous reforms in 1999 (Evans and Meade (2005), Meade (2005), Hansen (2004)). At the same time that the dominant generator was horizontally unbundled into competing companies, former restrictions on integration between generation and retailing were lifted. This coincided with other reforms requiring the ownership separation of retailing and distribution, resulting in the rapid downstream integration by generators into retailing. This structure was finally cemented in 2001, when a winter supply crisis resulted in soaring wholesale electricity prices, before which the largest non-integrated retailer NGC had opted not to renew hedge contracts. With retail customers on fixed prices NGC faced a severe price squeeze, quickly lost over NZ$300m, and consequently sold its retail base to generators. This move was reinforced by limited contract market development in the lead up to the 1999 reforms – in part a consequence of flaws in how contracting requirements had been imposed on the dominant generator (Hansen (2004)).

3.3 Why Contracts Haven't Developed as Anticipated

3.3.1 The Nature of the Contracting Problem in Electricity

While the mitigation of generator market power has often been proposed as an important role of contracts (e.g. Allaz and Villa (1993), though contrast Newbery (1998)), in practise risk management has proven to be the dominant purpose (Chao et al. (2005), Anderson et al. (2006), Finon and Perez (2008)). Risk management in turn is important for facilitating financing and investment, which has implications for supply security, and more fundamentally for business survival (an issue receiving greater focus in the light of prominent failures). Risk management by electricity operators is also important at a political level, in terms of business survival, supply security and price stability, since failures to achieve any of these increases the risk of large customer or voter backlash. In turn this affects the viability of decentralised electricity systems, with associated interventions such as wholesale price caps, state buying of contracts (e.g. California) or reserve generation requirements likely to distort incentives for generation and other investments (Joskow (2006), Meade (2005)).

Generators face both price and quantity risks in their output and input markets. While risks regarding the price or quantity of capital inputs are amenable to risk management in most developed capital markets (financial crises aside), the same is not always true for other inputs. Supply or price insecurity for gas, such as that in the UK with declining North Sea reserves or other European countries reliant on gas from Russia, create one set of risks. Similar risks arise for hydro generators exposed to variable inflows, storage constraints, and possible environmental regulation affecting off-take (as is the case in New Zealand – Evans and Meade (2005)). Uncertainty about plant availability creates additional input risk. On the output side generators face highly variable real time demand, as well as daily and seasonal load variations that may not align well with capacity. Real time demand variability can be especially costly where plant is costly or slow to "ramp up", such as for coal generation.[9] Moreover, given highly price-inelastic demand in the short-term, small changes in plant availability or demand shifts (e.g. due to weather changes) can result in highly volatile prices. These features can be exacerbated in systems with transmission constraints and locational pricing (such as PJM and New Zealand), since transmission system operators can "constrain off" or "constrain on" generation to maintain system stability, and significant spatial price separation can therefore result.

Similarly, retailers face price and quantity risks in wholesale and retail markets. They too face input quantity risk, especially where generators are input constrained (such as in hydro systems like New Zealand's with limited reserves) or have plant prone to outages (e.g. thermal). Such risks also correlate with price risks – often demand is highest in electricity systems precisely when prices are also highest (Chao et al. (2005), Meade (2003)), resulting in highly convex costs. Such convexity is shown to be an important rationale for hedging (Mackay and Moeller (2007)). On their output side retailers face relatively less price risk, in that smaller customers tend to have a clear preference for fixed price contracts. While this exposes retailers to price squeezes if they do not have hedged supplies, in principle they can reduce this risk with appropriate contracts. Like generators, however, retailers remain exposed to real time demand variability, and hence can be exposed to uncertain spot prices if their contract positions are inadequate.

Large customers, by contrast, face price and quantity risk in their output markets that is less correlated with that of retailers. Moreover, except for aluminium smelters, steel mills and other firms for which electricity costs are a significant part of their overall cost structure, large customers are not exposed to input price risks to the same degree as retailers (for whom energy costs are by far the biggest cost). They remain exposed to some degree, however, to price and quantity volatility in wholesale electricity markets, which affects their need and preference for hedging arrangements. Even when electricity costs are a small part of their overall costs, a secure electricity supply can be essential for their business viability, and hence hedging quantity risks (i.e. securing supply) may matter more to them than hedging price risks.

In terms of hedging short-term exposure to price or quantity risks, generators and retailers (and to a lesser extent large customers) are in principle natural counter-parties. By entering into hedge contracts they can lock in some part of their desired demand or assured supply, and at prices that need not be tied to volatile wholesale

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9 Wolak (2007) shows how a generator can reduce ramping costs and increase profit while accepting a lower average output price by smoothing its output through the use of a forward contract.

market prices. Retailers with spiking demand and fixed price customers will not wish to be exposed to spot market prices for top-ups; whereas generators will not wish to over-commit supply and be forced to purchase at spot prices to make up supply shortfalls. Consequently generators cannot afford to be over-contracted, whereas retailers cannot afford to be under-contracted, possibly creating an overlapping set of contracting preferences. Furthermore there is a natural role for generators that have uncorrelated input or output risks to contract among themselves rather than to bear the risk of having to trade in spot markets to make up supply shortfalls when over-committed, or sell surplus when under-committed. In that way they can hedge themselves against unforeseen plant outages, input shortages or input price hikes. This in turn enables them to issue contracts to retailers and generators over a larger share of their capacity without risking an unhedged exposure.

Large customers and retailers also share some ability to use contracting as a device to constrain generator market power. As mentioned above, requiring generators to commit some part of their capacity via fixed price contracts reduces their incentive to exercise market power, which is one reason why generation privatisations have sometimes involved vesting contracts. Contracting can be used by large customers or organised customer groups, however, as a more proactive tool to address market power concerns, sometimes in lieu of explicit regulation.[10]

In terms of supply security it might be thought that generators and retailers (or large customers) will share incentives to contract. Where common security obligations are imposed on all parties this might be so, but common pool resource (i.e. non-excludable but rivalrous) attributes of supply security do not ensure this if free rider problems are severe.[11]

3.3.2 Factors Undermining the Effectiveness of Contracting

Hold-Up Risks

A fundamental issue in using contracts to support generation investment is the divergence of the parties' preferred contracting horizons in most instances. The generation investments required for supply security are usually large, sunk and long-lived, creating a preference for generators, their funders and possibly fuel suppliers to secure investment returns for commensurately long periods. Entry costs in retailing are low by contrast, as are the costs of smaller customers changing their supplier. This exposes retailing firms to the risk of losing market share to new entrants if they fix their input costs by hedge contracts for any sustained period in which spot or contract prices then fall, inducing entry. In such instances retailers may either fail, or otherwise renege on their contract positions, stranding their generator counterparties.

Anticipating such classic hold-up problems by retailers exposed to retail predation, generators offer less contracts than they would otherwise prefer to offer. Not only does this increase their incentive to exploit market power in wholesale markets by increasing wholesale prices (Green (2004)) – thus making contracting potentially less attractive to retailers – but it also reduces the level of investment they can secure against supply contracts, and creates the additional risk of reduced supply security. If such hold-

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10 See Glachant et al. (2008) for a discussion of the German electricity sector model.

11 See Meade (2005) for a discussion.

up is sufficiently severe then generators too might find themselves financially at risk, and hence possibly renege on their own upstream contracts (e.g. with fuel suppliers). This is less an issue where generators are already integrated upstream with fuel supplies (such as coal-fired or hydro stations), but may give rise to cascading hold-up risks with gas or uranium suppliers which have their own large, long-lived and sunk investments. If this should result in sub-optimal upstream investments in exploration, extraction or transmission, this can serve to exacerbate the fuel and quantity squeeze risks faced by generators, resulting in reduced investment and supply security, and reduced contracting.

This hold-up risk also arises in respect of large customers that contract with generators. Where those customers enjoy market power in their own output markets they are at less risk of losing market share to competitors if they should happen to enter into electricity contracts at prices that prove to be too high. However large customers with competitive output markets may face hold-up risks that in turn induce them to potentially renege on their contracts with generators, thus reducing the supply of contracts, raising wholesale prices, and reducing investment and supply security. Long-lived investments that were made pre-liberalisation are vulnerable to being politically held-up by the reform process itself, particularly when it involves an unanticipated shift from regulated and smooth pricing (amenable to political lobbying) to volatile or increased prices set by market processes (less amenable to political control). Indeed, Anderson et al. (2006) report that participants in the NEM regard regulatory risk and ongoing reforms as their single greatest risk. If this is the case, then large customers that operate in competitive markets, and that are in a position where electricity price or supply security risks affect their ability to meet customer supply security and price requirements, face the risk of being out-competed by rivals that do not share those risks. Hence industrial structure has some capacity to influence hold-up risks in generation.

Both retailers and large customers also face the risk of being held up by generators, for example when replacing expiring hedge contracts. For large industrial customers at least this may pose the greater risk than the hold-up risk they pose for generators, particularly if they operate in competitive output markets. This is because any given industrial customer may account for a fraction of a generator's output, whereas any given generator may account for a large share of their supply. However, if a secure electricity supply at a competitive price is important for the ongoing competitiveness of industrial customers (e.g. aluminium smelters) then the location of their plant would presumably have been decided on the strength of the long-term electricity supply contracts they could negotiate at the outset, which reduces their exposure to generator hold-up.

For the reasons discussed above the problem is more finely balanced for retailers. For incumbent retailers the reform process itself creates its own hold-up problems, whereas entrant generators have the benefit of determining whether reformed market conditions enable economic entry. In each case the incentive for retailers not to contract for more than a few years has to be balanced against the benefits they might enjoy by securing longer-term contracts with generators.

Where the balance of risks lies – i.e. whether generators or retailers face the greater risk of being held up by the other – reflects a wider consideration in this analysis. Specifically, hold-up risks are most pronounced where either party has undiversified positions. For example, a generator with geographically dispersed plant and a mixture of fuel types is less exposed to quantity squeezes than a merchant generator with a single plant. Moreover, a generator with a portfolio of supply contracts combining a mixture of loads can smooth out demand volatility that both reduces quantity squeezes and also its exposure to hold-up by any one customer. Facing a smoother load profile means it is also able to write contracts over a greater share of its capacity, all fuel and other supply risks being equal. Similarly, retailers with a portfolio of supply contracts for different maturities and/or from different generators diversify their exposure to hold-up by any one generator. A merchant generator with a single off-take agreement or a retailer with a single supply agreement is clearly in a more vulnerable position.

Adverse Selection Risk due to Market Power and Asymmetric Information

Generator market power and information asymmetries can conspire to create adverse selection problems for retailing firms and large customers which further reduce their willingness to lock themselves into long-term contracts, particularly if contract prices are temporarily high (e.g. as in the lead-up to peak demand periods in New Zealand when hydro storage is low). Aside from the general difficulty in predicting supply and demand conditions more than a few years out (Anderson et al. (2006)) – an example of bounded rationality that hinders effective contracting – these parties can be reluctant to contract with generators whom they believe to possess market power, as well as better knowledge than they about impending outages or fuel insecurity. Where contract prices are perceived to be neither competitive nor reliable then this only increases the risk that they enter into a contract price and then face being out-competed in fixed price retail markets by competing retailers (or in product markets by competing industrials) who can secure more favourable prices through either superior information or greater negotiating leverage.

Market Illiquidity

This adverse selection problem, leading to generator hold-up risks, is only made worse by the general problem of illiquid forward markets for which standard arbitrage pricing conditions do not hold. Since electricity is not economically storable, contracts for forward delivery of different maturities are effectively contracts for distinct commodities – energy at defined future times. This thins the relevant markets – exacerbating potential market power issues – and means temporal hedge markets do not satisfy arbitrage relations based on storage costs. Arbitrage is made even more difficult in systems with transmission capacity auctions (such system residue auctions for interconnector congestion rents in the NEM, interconnector capacity auctions in the EU, or FTR auctions), due to asynchronous energy and transmission auctions (Anderson et al. (2006)). Additionally, the delivery of electricity has a spatial dimension in systems with transmission constraints and either zonal or nodal pricing, which further thins the relevant forward markets.

Outages, Fuel Risk and Load Profiles

Generators exposed to significant input risk will prefer *force majeure* or other availability clauses that do not commit them to supply during outages or fuel shortages. Retailers or industrial customers may be prepared to accept such clauses if generation is constrained and contracts are in short supply, but in general they will prefer contracts that follow their own load profile and demand swings, rather than generator supply availabilities. They will also prefer asymmetric instruments such as options which limit both their quantity and price risks, which generators will not prefer. Hence, while supply and demand preferences may align – such as aluminium smelters contracting with base load generators, or retailers hedging peak demands by contracting with peak generators – any divergence of preferences limits the standardisation of hedge contracts and thus reduces the liquidity of hedge markets. Indeed, generators preferring continuous supply are likely to seek a premium if they are to be induced to commit some of their output to supply an uneven load. Conversely, generators with seasonal (e.g. run of river hydro) or other temporal supply patterns will prefer contracts that align with those patterns, and will also seek a premium to write contracts that do so poorly. Writing contracts that do not align with their supply profiles leaves generators with uncommitted supply that may be harder to contract. Both sides to a contract will therefore need to weigh whether their interests are better served by contracting at a price, or to only contract to a more limited extent so that residual contracting options are preserved (especially when demand or supply conditions are particularly volatile).

Relative Risk Aversion

Misalignment of contracting preferences is exacerbated by differences in relative risk aversion between the parties. For example, Anderson et al. (2006) report that state-owned generators in the NEM are more risk averse than private generators. This may bias them in favour of greater contracting relative to private generators, but also increases their preference for contracts that do not commit them to supply during outages or fuel shortages. Private generators by contrast may be less inclined to issue contracts (all other things being equal), but be more prepared to offer terms favouring customers who do not wish to bear outage risk. Depending on the fuel type and variety of private and state-owned generators, such differences in risk preferences could create distinct sub-markets for contracts.

Contracting problems become more severe if generators have market power and are also less risk averse than retailers and large customers. Such a reduced level of risk aversion could reflect soft budget constraints in the case of state-owned generators, or the possibility that generators' input and output risks are to a greater extent off-setting than those faced by their customers. In this case generators have less incentive to write contracts for two reasons – first they do not wish to reduce their ability to increase prices, and second they have less need to hedge in the first place. This does not mean that they will offer no contracts, but rather that contract prices will be higher, contract volumes will be lower and contract terms will be less favourable than if generators did not enjoy market power or have relatively low risk aversion.

Initial Conditions

The success or dominance of contracting as a governance device for managing risks in liberalising electricity systems also reflects the initial conditions at the commencement of reforms. Where decentralised systems emerge against a backdrop of significant excess capacity, for example, generators will be more likely to offer contracts for sale and to do so on more favourable terms (e.g. with less protective force majeure clauses or better demand load matching) than if this were not the case. In the same circumstances, however, retailers or large customers face less imperative to sign such contracts, and indeed may prefer not to do given that prices will already be relatively low. As demand grows and excess capacity diminishes, the supply of contracts may shrink at the same time that customers increasingly prefer to hedge against future price rises, unless large customers (for example) are prepared to contract forward to secure investments offering them greater security of supply. Such forward contracting is facilitated where those customers enjoy some degree of market power in their output markets, or their competitors are also locked into the contracts (e.g. via joint venture).

The extent of pre-existing vertical integration or long-term contracts also plays a role. While vesting contracts are often imposed on dominant generators as a means to constrain their market power as liberalisation unfolds, even in horizontally de-integrated systems pre-existing contracts or vertical integration affect the supply of and demand for contracts. Systems with large industrial customers on long-term contracts signed pre-liberalisation often inherit those contracts as states seek to mirror their commitments in a way that does not crystallise or reveal liabilities to taxpayers. A consequence of this, however, is that the evolution of contracts markets will necessarily be constrained by the scope and terms of such contracts. Similarly, vertical integration, with large customers or otherwise, will also affect contract market evolution since the supply of and demand for contracts will be lower, and hence contract markets less liquid, if significant vertical integration already exists.

With these limitations of contracting in mind, we now turn to the merits of vertical integration as an alternative, and also consider some possible fixes to the problems of contracting for risk management in decentralised electricity systems.

4 Remedying the Contracting Problems – Vertical Integration and Alternatives

This section argues that vertical integration – supported to some degree by spot and longer-term contract markets – is a more natural and self-sustaining approach to risk-management in decentralised electricity systems. As a consequence it offers benefits over contracting in additional areas such as investment and security of supply. The section begins with a general discussion of the benefits of integration, and then considers instances in which particular cases of upstream and downstream integration are to be preferred. Finally, alternative approaches to vertical integration – which involve directly addressing the failures of contracting in electricity systems – are considered. These include regulating for contracts, reducing retail-level competition, and various demand-side fixes. Apart from the latter, these alternatives are argued to be unnecessary, counter-productive, excessive or otherwise inferior, in general, to or in the presence of vertical integration.

4.1 Vertical Integration

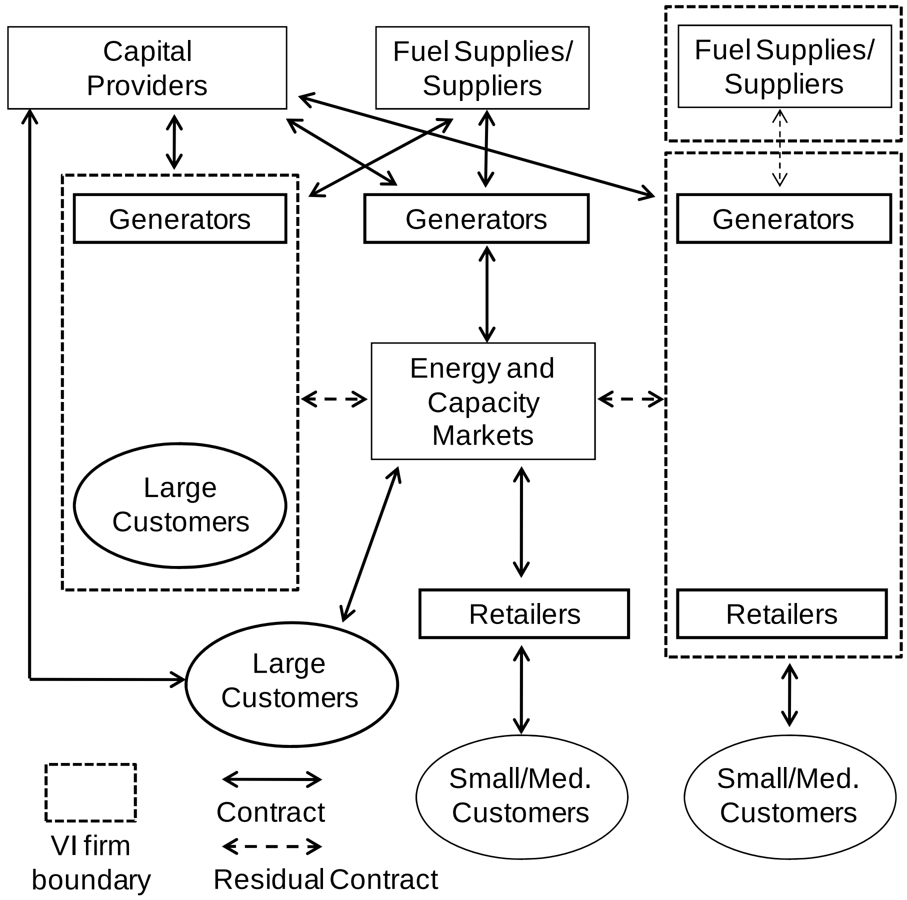
4.1.1 General Advantages Relative to Contracting

Internalising Costs and Risks

In Section 2 we argued that vertical integration internalises a range of costs (and risks) within the firm that otherwise must be managed through contracting. It is preferable to do so when the costs of contracting exceed the costs of internal organisation. Section 3 identifies the particular costs of contracting in decentralised electricity systems – many of which result from mismatches between generators and retailers. These include mismatches in input and output volatility, asset specificity, investment horizons, information about supply and demand, degree of diversification and market power. They also arise due to regulatory risks. Because of these, contracts have inherent limitations that hinder the achievement of their fundamental purpose – the management of price and quantity risks.

Whether customers integrate upstream into generation or vice versa, either way wholesale price risks become largely moot. If wholesale prices are too high then one part of the firm gains while the other loses. Since the role of contracting under vertical integration is reduced to covering only any remaining uncommitted (or over-committed) capacity, wholesale prices play a much reduced role, and hence any volatility in wholesale prices similarly is of less consequence in the firm's objective function. Indeed, while spot market prices typically allow recovery of only short-run marginal production costs, integrated firms are concerned more with the recovery of long-run average costs, going some way towards addressing the "missing money" problem identified in Joskow (2006), and therefore supporting investment and supply security. *Figure 3* illustrates how integration changes firm boundaries so as to reduce or eliminate the role of wholesale electricity prices otherwise faced via contracting.

Figure 3: Internalising Wholesale Prices via Vertical Integration



Better Long-Term Matching of Capacity and Load

Vertical integration also provides a long-term match between generator and customer preferences in terms of supply-security and load matching. Retailers fearful of short-term wholesale price spikes for which durable contracting arrangements are not available can invest in peaking plant. Large customers with unusual or seasonal load profiles (e.g. dairy processors or pulp and paper processors) can invest in co-generation plant with output that correlates with their production patterns and that also affords them greater control over their achieved level of supply security. Conversely, generators with diversified plant can not only hedge their input price and quantity risks, but by having a smoother supply profile they are better placed to integrate with a diversified customer base. Such diversification presents the generator with a less variable load profile, but also reduces the generator's exposure to the loss of any particular large customer, or group of customers. In other words, for any given level of retail entry risk (or output market competition for large customers), diversified and integrated firms are less exposed to the hold-up risk arising with non-integrated customers.

The combined effect of marginalising the integrated firm's exposure to wholesale price risk, and enabling a better matching of capacity and demand characteristics, means that vertical integration more effectively manages wholesale price risks than does contracting. Moreover, it does this on a secure long-term basis, whereas contracting achieves effective risk management – to the extent it does – only for the contract horizon, which in practice is for only a limited period. Beyond that horizon contracting parties are exposed to renegotiation risks not shared by integrated firms. Internalising the limited wholesale price risks to the firm thus provides a more durable hedge.

Reduced Market Power and Regulation Risks

Furthermore, just as contracts reduce the incentive for generators to exercise market power, so too does integration, with the benefits of integration for wholesale prices being tied to the degree of balance between generation and retailing activities, not the degree of generator market power per se (Hogan and Meade (2007)). Hence, while vertical integration thins the markets for contracts, it has the positive externality that it reduces the problems of generator market power, and also asymmetric information and strategic bargaining, that otherwise would be commonplace in contract markets. Generators face less incentive to exploit any short-term informational or bargaining advantages they may hold when the bulk of their output is already committed to their integrated customers.

On the other hand, integration also creates information asymmetries that further benefit the integrated firm and support investment. Specifically, by internalising wholesale prices to the integrated firm, such prices become a less reliable signal to regulators and policy makers regarding firm conduct and reform success. Rising, spiking or highly volatile wholesale prices can give rise to calls for greater regulatory intervention, such as wholesale price caps. However, with integration the case for such intervention is reduced, as is its impact. The case is weaker because integrated generators with balanced portfolios have less incentive to exercise wholesale market power, and if customers are on fixed price contracts offered by integrated generators then they are insulated from wholesale price movements anyway. The impact of price regulation is weaker (relative to the impact on non-integrated firms) because wholesale prices are relevant to integrated firms only at the margin – so it is only at the margin that any regulatory costs or benefits would accrue. Furthermore, an integrated firm's more important decision variables – such as fuel stocks and average production costs – are not known to regulators, further complicating any attempt to regulate it. Thus vertical integration provides a natural hedge against regulatory intervention.

Reduced Hold-Up Risk

Importantly, vertical integration fundamentally reduces the risk of hold-up that can plague non-integrated electricity systems reliant on contracting. As discussed in Section 3, hold-up risk originates with the risk of competitive entry in retailing (or product market competition for large customers), and then cascades upstream into generation, and beyond that to fuel and capital supplies. By thinning contract markets vertical integration immediately reduces the scope for retail entry, since any new entrant of scale would need to also invest in generation capacity. This requirement for joint investment in both retailing and generation significantly raises entry costs for potential entrants, thus deterring entry and hence hold-up risk.

Simultaneously, even if retail entrants were not required to invest in generation, the fact that they can access only reduced contract capacity means any existing scale mismatches between retailers and generators are emphasised. Generators are often much larger than retailers, meaning that competitive entry by a non-integrated retailer will only vie for some portion of the customer base of an integrated generator. This automatically reduces the generator's exposure to hold-up and failure, should the entrant retailer succeed. However, the integrated generator needs only to ensure it can recover long-run average costs to ensure its survival against entry. Hence even if it matches the entrant's prices for its at-risk customer classes it may still remain viable, particularly if it relies on more modest debt financing rather than highly-leveraged project financing. Moreover, in principle it can cross-subsidise at-risk customer classes using any non-at risk customers, further ensuring its financial viability in the face of entry. Indeed, integrated firms are potentially further insulated from hold-up risk if these scale mis-matches are increased when contract markets are thinned by integration.

The Virtue of Transmission Constraints

The advantage of vertical integration over contracting in terms of reduced hold-up risk can also arise from an unexpected quarter – transmission constraints. In systems such as the UK's where there are relatively few transmission constraints national energy prices and postage stamp transmission charges are supported. In turn this facilitates retail entry and hence hold-up risk at a national level. By contrast, in systems such as New Zealand's with significant transmission constraints and locational energy pricing reflecting transmission constraint and loss rentals, retail competition is often more regionally defined. This is because transmission constraints can result in significant and often unpredictable price separation between pricing nodes (i.e. grid injection and exit points). In the absence of tools to mitigate the risks to generators and customers of such price separation – such as financial transmission rights or the NEM's system residual auctions – such price separation can expose either generators or customers to the risk of significant under-hedging via contracts. In New Zealand, for example, energy hedge contracts are often available only for key reference nodes, and significant price separation can occur between those nodes and others. Hence if any party seeks to hedge its price risk at other than these reference nodes using contracts it cannot do so in respect of congestion rents and transmission losses, unless it has physical hedges above or below the relevant constraints.

Since nodal electricity systems with grid constraints can be electrically balkanised, this presents natural barriers to non-integrated retail entry. Such barriers are made worse when integrated generators also operate in the same "regionalised" sub-system of the grid. While non-integrated retailers reliant on contracting are at risk of nodal price separation, limiting their ability to align supply costs and output prices, integrated generators may have plant above and below constraints which provides them with the required physical hedge against price separation. Indeed, it is also possible for generators with plant either side of a constraint to game the constraint so that it becomes binding with the result that competing retailers are exposed to price separation, while its own plant downstream of the constraint is dispatched at a higher price.[12] In an apparently perverse way such electrical fiefdoms created by grid constraints protect integrated generators with spatially dispersed capacity against excessive retail competition.

Hence, just as encouraging retail competition may have the unintended consequence of worsening hold-up risk, limiting investment and creating supply insecurity, so too might moves to introduce greater wholesale competition through removing grid constraints, or introducing mechanisms such as FTRs for market participants to hedge their exposure to congestion rents and transmission losses. Indeed, while introducing greater generator competition in wholesale markets is often the

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[12] For a discussion of such gaming in the context of an evaluation of a FTR proposal for New Zealand see Evans and Meade (2001).

primary driver of reducing transmission constraints, this objective becomes moot provided generators are integrated and have balance between capacity and load (since, then, incentives to exercise wholesale market power are reduced). Hence, given any level of retail competition, the possible benefits of grid constraints in terms of reduced hold-up risk require consideration.

Investment Benefits of Fuel Uncertainty in Hydro-Based Systems

In a similar vein, electricity systems in which fuel uncertainty can result in sustained electricity price rises may also benefit generation investment. While demand spikes, grid failures or generation outages can cause transitory surges in wholesale electricity prices, systems in which hydro storage is limited or uncertain can sustain such surges – sometimes for months. Such hydro limitations contributed to the NordPool spike of 2002-03, as well as the Californian crisis of 2000-01 (Amundsen and Bergman (2006)). They have also been a regular cause of significant and sustained wholesale price rises in New Zealand in the "dry winters" of 2001, 2003, 2006 and 2008, as illustrated in *Figure 4* (overleaf).[13] New Zealand has winter-peaking demand (for heating rather than summer cooling), as well as volatile hydro inflows and limited hydro storage.The fact that 60-65% of generation capacity is hydro-based means the system is therefore highly vulnerable to poor hydro inflows to its storage system.

As can be seen, there is a significant correlation between wholesale price rises and negative hydro balances. There are also sustained periods in which tight hydro balance and strong winter demand (largely weather-dependent) result in wholesale prices many times average levels (though nowhere near the peaks experienced in other – interconnected – systems). Importantly, such systemic and sustained price rises are not amenable to short-term politically-motivated responses such as price caps, since they could materially distort generator incentives to supply precisely when they are needed to most. In turn that would worsen supply security and result in even higher political costs than those arising under high wholesale prices (which affect large industrial customers if they do not have adequate hedge contracts, but which only slowly feed through to increases in otherwise fixed prices for smaller customers).

Consequently such hydro-based systems can produce significant "scarcity rents" to support new generation investment. While the wholesale price rises can be (and are) often attributed to abuse of generator market power, they can also arise for benign reasons such as a significantly increased opportunity cost of water and the associated real options value from deferring generation (so as to preserve scarce hydro resources for possible increases in future demand – e.g. Amundsen and Bergman (2006), Evans and Guthrie (2007)). Thus such systems may be more immune to the "missing money" problem referred to by Joskow (2006), and consequently better able to support generation investment.

As discussed in Section 3, generators' exposure to fuel uncertainty complicates contracting in electricity systems. Where such uncertainty is systemic and potentially prolonged, generators will naturally incline towards contracts with force majeure clauses that protect them against contract breach in the event of non-delivery. In precisely the same situations, however, large customers and retailers would prefer to not face such clauses, unless they have significant ability to curtail load. In vertically integrated systems,

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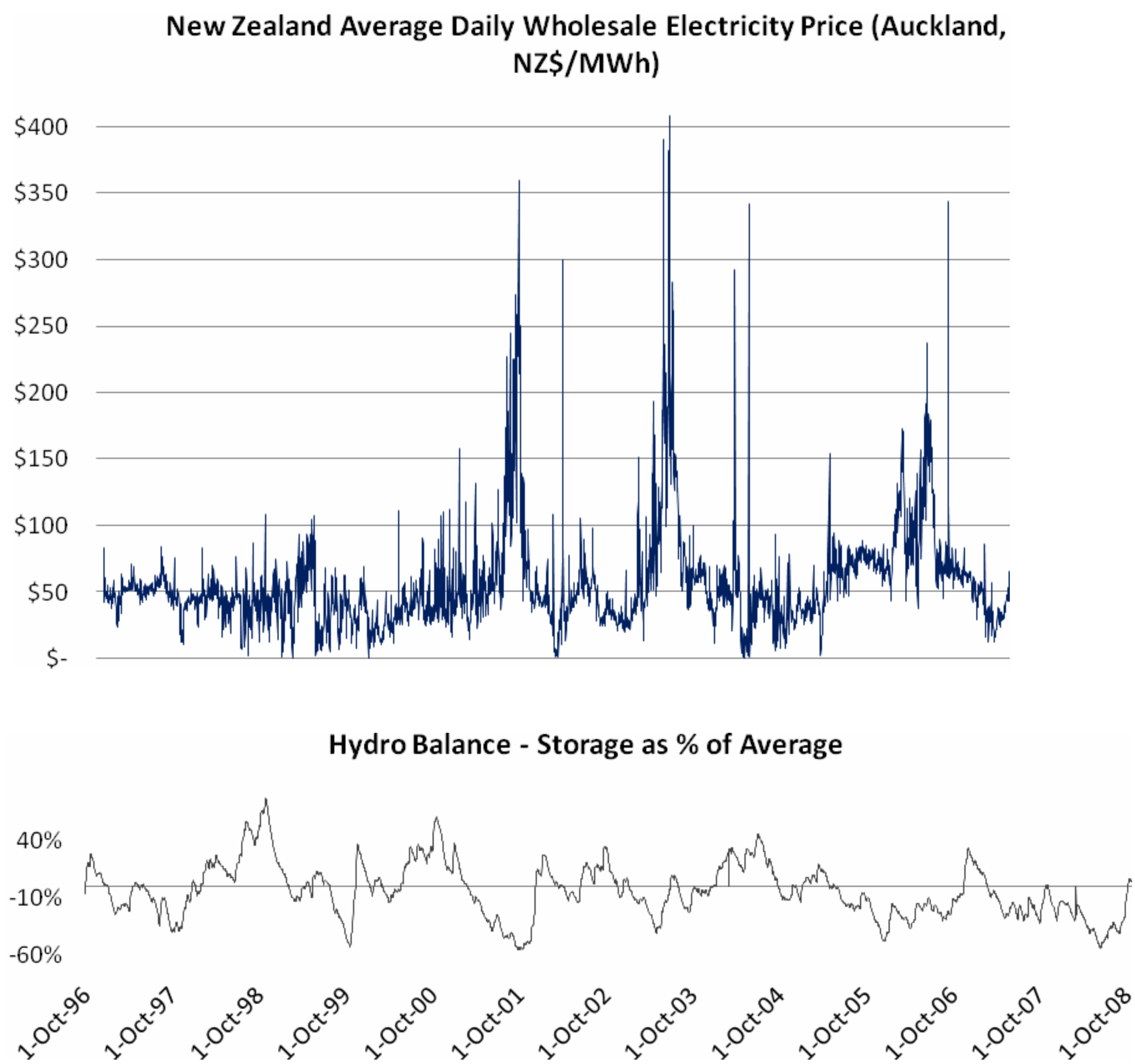
[13] For a discussion of the 2001 and 2003 winter "crises", and a comparison with earlier New Zealand experience with supply constraints, see Evans and Meade (2005).

by contrast, these risks are internalised to generators, and increases in fixed retail prices (and hedge contract prices) following sustained increases in wholesale prices therefore support new generation investments.

Figure 4: Wholesale Price Rises and Hydro Balance in New Zealand



Source: Data courtesy of M-Co.

Favourable Comparative Ownership Costs

Thus far the arguments in favour of vertical integration have focused on contracting cost savings. As mentioned in the introduction to this section, vertical integration is to be preferred to contracting only if contracting costs outweigh the costs of internal organisation. It is possible, however, that vertical integration involves both contracting cost and internal organisation cost savings, meaning it dominates contracting as a form of governance. This view is reinforced by the fact that vertical integration is becoming either the dominant or an increasingly prominent governance mode in both systems without significant contract markets (e.g. New Zealand – see Meade (2005), Hansen (2004)), or those with relatively liquid contract markets (e.g. Australia – see Simhauser (2008), Anderson et al. (2006), Chester (2006) – and the UK – see Pollit (2007), Thomas (2004), Roques et al. (2005)). Contracts, by contrast, are often an imposition of liberalisation processes, or artefacts of historical arrangements (e.g. long-term state contracts with large industrial firms). Hence they possibly represent a dominated governance form arising exogenously (e.g. reflecting wider political constraints) rather than as an endogenously-determined institutional form.

The case in favour of upstream integration into generation by individual or groups of large industrial customers appears relatively straightforward. Particularly when such integration involves use of co-generation, such integration involves horizontal diversification of existing industrial processes. In any event such firms are likely to be adept at managing large-scale capital investments and running industrial processes, suggesting the internal organisation costs of integration are not large. Furthermore, to the extent that integration requires them to be able to contract in wholesale markets for any over- or under-capacity, this is less so than if they are reliant solely on contracting.

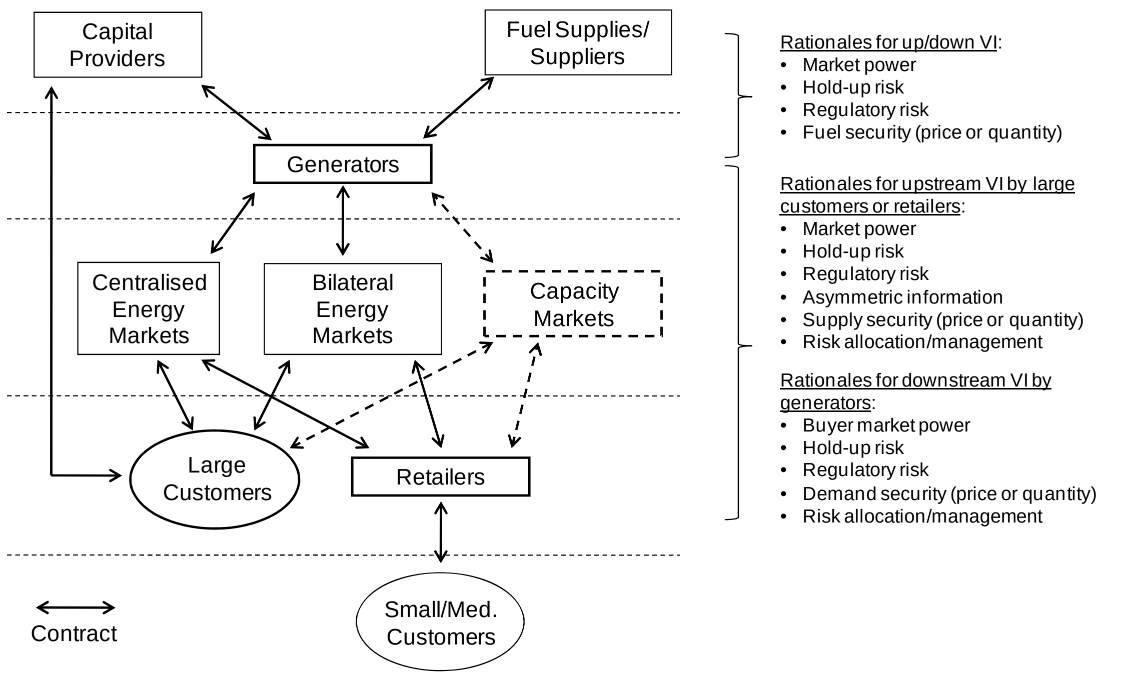
In respect of integration involving retail customers there is possibly a case against retail customers directly owning upstream generation, since they would require contracts with their supplier in any event, and direct ownership would add ownership costs as well (particularly where customer interests are not homogeneous). However, smaller customers are commonly aggregated via retailers, so upstream or downstream integration via (or into) such collective governance vehicles allows scale economies in ownership costs. The additional costs of internal organisation may be small, even if retailing and generation are distinct types of business activity. One board can effectively monitor more than one firm division, and transfer pricing rules between divisions (i.e. the internal "wholesale market" price) should make any divisional conflicts of interest transparent to the firm and hence inherently manageable.

Complementary Role of Contracting

While the advantages of vertical integration relative to contracting suggest it is a more natural governance form in decentralised electricity systems, this is not to suggest that contracting is redundant in integrated systems. For some of the same reasons that complete contracting is untenable, perfectly balanced vertical integration is also not to be expected. Foremost in this regard is the problem of input and output variability faced by generators. Those with uncertain fuel supplies will be willing to integrate only to the extent that they expect to be able to meet their embedded load using native generation a significant proportion of the time. To the extent they have too much load, at least under some fuel supply scenarios, they must supplement native generation capacity by purchases from other generators, either on spot or longer-term contract markets. While the risk this presents to their overall profitability is likely to be significantly less than for suppliers reliant solely on contracting, some risk remains. Conversely, if generators under-integrate they will seek to off-load some of their excess capacity via spot markets or contracts, the returns from which will have different risk characteristics. Hence even integrated generators will seek to access spot and longer-term contracts markets to some degree.

Before proceeding to a discussion of the relative merits of different types of vertical integration in decentralised electricity systems, *Figure 5* summarises how the location of contracting costs gives rise to differing rationales for integration.

Figure 5: Rationales for Vertical Integration in Decentralised Electricity Systems



4.1.2 Upstream Vertical Integration by Large Customers

As already discussed, upstream integration by large customers need not significantly increase internal organisation costs while possibly producing significant contracting cost savings. The frequency and extent of any contracting is reduced by integration, since some or all of the firm's energy requirements are met internally. Horizontally diversifying industrial processes into generation – particularly where co-generation is involved – should present little additional managerial load. Furthermore, co-generation allows the firm to naturally align its production capacity and load profile in ways that contracting with external generators may not allow, both reducing contracting costs and boosting supply security. It also enables such firms to hedge their input risks, especially where their co-generation inputs are also by-products of their industrial processes (e.g. biomass in the case of pulp and paper manufacturers). Reduced reliance on contract markets leaves large customers less exposed to generator market power, information advantages regarding fuel supplies, strategic bargaining and hence adverse selection and hold-up risks in contract (re)negotiation. Examples of such upstream integration can be found in the New Zealand and Finnish pulp and paper sectors, as well as the Queensland aluminium smelter sector (although this may have been the result of the subsidised acquisition price – see Turton (2002)).

4.1.3 Upstream Vertical Integration by Retailers

Upstream integration by retailers into generation may be constrained by scale differences between the two types of business, as well as possible capital constraints.

However, in some cases there can be significant alignment between retailer preferences to avoid wholesale price spikes and the risk-management characteristics of peaking plant investment. Importantly, the incentive for such upstream investment is affected by regulatory or system operation decisions such as price caps or reserves management which affect wholesale price peaks. Stand-alone peaking investment relies on transitory scarcity rents in wholesale prices, and hence can be made non-viable by constraints on price spikes. Similarly the rationale and viability of upstream integration by retailers is also reliant on such (avoided) rents. Thus upstream integration by retailers may not be as sustainable as downstream integration by generators.

Where such upstream integration is viable it also protects retailers against the possible exercise of generator market power, which is most likely to be exercised in periods of tight system balance and hence already high wholesale prices. It also therefore protects retailers against generator informational advantages regarding capacity availability, and reduces their adverse selection risk otherwise faced in negotiating hedge contracts. By internalising the costs of retail-level hold-up, retailer investments in peaking capacity are made more viable, which in turn provides credible commitments to funders of and fuel suppliers to such generators.

4.1.4 Downstream Vertical Integration by Generators

Downstream integration by generators into retailing can arise for both natural and artificial reasons. As discussed above, generators have scale and balance sheet advantages that favour their integration into multiple retailers, as opposed to integration by multiple retailers into generation (which would raise additional internal organisation costs). Furthermore, generators integrate into retailing not to avoid spiking wholesale prices (which they would otherwise prefer to face in contract markets), but rather to provide a natural hedge against low prices in the context of long-lived investments. This makes them naturally less exposed to regulatory or system operation interventions that serve to depress wholesale electricity prices.

Other reasons favouring downstream integration into retailing rather than upstream integration into generation include barriers to generation ownership. Capital market constraints are one possible barrier, particularly where capital market development or depth are insufficient for retailers to raise the large sums required for upstream investments into diversified (rather than single plant) generators. In New Zealand an additional barrier is state ownership of most of the competing generators (Evans and Meade (2005)). Even if retailers had the capital to acquire generation, they would be reliant on contracting or generator break-up to off-load any surplus capacity acquired, but more importantly the bulk of that generation has simply not been for sale due to political opposition to privatisation. In contrast, retail companies were available for purchase as a consequence of legislation unbundling distribution and retailing, meaning generators were able to buy into such retailers.

Another rationale for downstream integration involves generators acquiring customers to limit their exposure to buyer market power. While this exposure may not naturally arise in respect of retail customers, it may do so as a consequence of regulation, or in respect of industrial customers. In Australia, for example, aluminium smelters have some flexibility over their location, and hence can exert buyer power over stranded generation investments by threatening to relocate when renewing long-term contracts. Conversely, state buying agencies on behalf of retail customers may exert buyer market power that generators would prefer to avoid through the direct ownership of customer bases (e.g. industrial customers, since they are more likely to operate in unregulated markets, and the transaction costs of acquiring them may be favourable compared with acquiring a base of retail customers). The costs of such hold-up or regulatory risk would need to be significant given the internal organisation costs involved in acquiring non-retail customer bases, however, since generators may lack the expertise to adequately manage activities outside of the electricity sector.

4.1.5 Upstream Vertical Integration by Generators

As highlighted in Section 3, hold-up problems at the retail (or large) customer level can cause cascading hold-up problems upstream in not just generation, but also further upstream in capital and fuel supply. While there would appear to be little rationale for upstream integration by generation into capital supply (e.g. banking), except perhaps in countries with very poorly developed capital markets and/or capital controls, integration into upstream fuel supplies is both more natural and common. Coal-fired power stations are often combined with coal-fields (e.g. as in Victoria), perhaps reflecting hold-up risks in respect of coal varieties that cannot be economically transported from competing non-integrated mines. In New Zealand two major integrated generators have considered joint investment in the development of a LNG terminal, and also in gas field exploration, to develop secure gas supplies for thermal generation.

The New Zealand example illustrates three different issues in relation to upstream investment by generators. First is the possibility of hold-up in third party gas exploration, since these generators have large sunk investments in thermal generation that could be stranded once existing gas supplies wind down sooner than originally expected. Second is the potential hold-up risk faced by an independent gas explorer, particularly given uncertainty in government policy regarding future thermal generation investments.[14] However, unlike the development of previous gas fields in which domestic demand was required to recoup development costs, LNG possibilities now allow for the export of any gas not used domestically. The third is the possible importance of vertical integration in providing the funding security for such upstream investments. Without embedded customers both generators and fuel suppliers would face downstream hold-up risks that potentially impede such investments.

Another possible rationale for upstream integration into fuel supplies is to remove exposure to volatile input prices or quantities. This risk is becoming evident in European gas supplies, given the increasing market power exerted by Russia. In the same way that integration into customers internalises wholesale electricity prices to the firm, so too does integration into gas supplies. Additionally, integrating into fuel supplies also enables generators to reduce their exposure to adverse regulation. For example, while regulation of fuel prices may provide generators advantages in terms of reduced input costs, this may be unhelpful to generators if it also suppresses upstream capacity investments or exploration. Upstream integration therefore enables generators to improve fuel supply security or to better manage price risks, reducing their risk of price or quantity squeezes and therefore supporting their generation investments.

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[14] In December 2008 a newly-elected government overturned legislation passed by its predecessor in September implementing a 10 year ban on new thermal generation (except where such generation was required for supply security or replaced less efficient thermal plant).

While the internal organisation costs of upstream investments by generators may be large, hold-up risks in fuel supply mean that contracting may be particularly costly, justifying the costs of integration.

4.1.6 Downstream Vertical Integration into Generation

Downstream integration into generation by upstream suppliers sometimes arises. As discussed above, there is a possible rationale for downstream investment by fuel suppliers where they are exposed to hold-up by generation. This might arise, for example, for low-calorific value coal that cannot be economically transported to alternative customers if the coal field operator is held up by a generator customer. Alternatively it might arise for a gas field developer if there are inadequate domestic alternatives to generator buyers, which might arise if sales to non-generators require additional infrastructure investments such as in transmission or LNG terminals.

In New Zealand a more unusual example arises, namely that by a wind turbine manufacturer, NZ Windfarms. The company manufactures wind turbines tailored to the New Zealand wind generation environment, and it part owns generators that use its technology. Even more unusual is the company's reliance on spot prices rather than longer-term contracts to provide investment returns. In part this is because of its stated belief that rising thermal generation prices as well as an emissions trading scheme legislated in September 2008 will cause spot wholesale prices to rise over time. Its downstream integration appears to be a means by which it establishes the viability of its wind generation technology – a form of market creation, rather than a means to eliminate hold-up risks.

4.2 Alternative Contracting Fixes

With these advantages of vertical integration relative to contracting in mind, we now briefly consider possible non-integration based fixes to the problems of contracting in decentralised electricity systems. These include regulating for contracts, reducing retail competitiveness – such as through reinstating or retaining retail franchises – and other demand-side fixes unrelated to retail competition.

4.2.1 Regulating for Contracts

Regulating for contracts is often the principle driver of contracting in decentralised electricity systems. Vesting contracts are commonly employed to limit market power and provide wholesale price certainty in liberalising systems, particularly while generator market power is seen as an important risk. Virtual power plant agreements are sometimes imposed on incumbent dominant generators as a means to reduce their market share while deferring horizontal de-integration or generator privatisation. Long-term contracts can be imposed on generators so that liberalising states can offload legacy long-term supply contracts previously entered into with industrial customers. Also, contracts have been imposed in states where liberalisation processes have not performed in a politically sustainable way, giving rise to reactive interventions (e.g. California, Ontario – see Chao et al. (2005) and Tetrault (2006) respectively).

Regulating for contracts can also arise in other guises. Legislation establishing an industry regulator in New Zealand included powers allowing a newly-created regulator – the Electricity Commission – to require integrated generators to sell some proportion of their output via contracts (Meade (2005), with Willems and De Corte (2008) providing a rationale for such regulation). Doing so means that all generators would become over-committed given their existing embedded load, and have to divest a certain amount of that load in order to restore balance. If they did not do so this begs the question as to whom would buy such contracts absent a natural customer base. If inadequate entry arose following the imposition of such a regulation then generators would remain overcommitted, which raises their incentives to increase wholesale prices (Hogan and Meade (2007)). The Electricity Commission has to date opted not to exercise its powers in this area, preferring alternative approaches to supporting hedge market development such as mandating price transparency (Electricity Commission (2006), UMR Research (2008)).

The fact that regulation may be required in order to sustain contracts markets begs the question as to the market failure such regulation is intended to remedy. This is especially so if vertical integration has been dismantled or prohibited as part of a liberalisation process. If either is the case then a potentially endogenous approach to risk management has been artificially precluded, and so the basis for regulating for contracts is potentially faulty. Where vertical integration is permitted, however, but does not arise, a more natural question is why such integration might be impeded, rather than why contracts need to be encouraged. If there should happen to be natural impediments to vertical integration then there is a clearer rationale for contracting, and hence regulating for contracting might have a more sound rationale.

4.2.2 Reducing Retail Competitiveness

It is curious that hold-up problems have arisen in electricity sectors as a consequence of retail competition, given that competitive entry into retailing has been less than comprehensive (Defeuilley (2008)). Indeed, aside from barriers to retail entry such as transmission constraints and vertical integration, there are a range of reasons why customers have proved reluctant to switch to new suppliers. Among these are bounded rationality (e.g. customers' inability to understand new retail contracts), and a lack of customer motivation (e.g. because power bills are often only a fraction of overall household expenditures, so any switching savings are relatively modest). Retail customers can also be reluctant to switch suppliers if only short-term contracts are on offer in case they face price increases after switching (although Defeuilley (2008) reports that the gains from switching tend to be sustained, with incumbent prices typically exceeding entrant prices over time). Other explanations include the risk of disconnection from changing suppliers, loss of loyalty benefits, or relative unfamiliarity with and hence possible distrust of new suppliers. While some "active" customers are highly price-sensitive and inclined to switch (Amundsen and Bergman (2006)), most customers are "inactive" and remain loyal to their incumbent supplier.

Additionally, states experiencing the highest levels of customer switching are often also those implementing measures favouring entry. For example, Defeuilley (2008) reports that Texas, Victoria and South Australia all implemented price regulations designed to encourage entry, for example with incumbent Texas suppliers required to offer a regulated "price to beat" until their franchise market share fell below 40%. Hence, to the extent that retail entry in such jurisdictions has resulted in hold-up problems, this may be a consequence as much of pro-competition regulation as much as flaws in contracting or vertical integration.

Such considerations aside, some authors have proposed the retention or reinstatement of retail franchise areas as a solution to hold-up problems created by retail entry (Chao et al. (2005), Roques (2008), Newbery (2002, 2005). Doing so means retailers have locked-in customer bases that are insulated from competitive predation. This in turn reduces their incentive to renege on contractual commitments to generators, and affords them greater protection against predation when entering into longer-term supply contracts. This reduced hold-up risk induces generators to commit a larger share of their output via contracts (assuming they are not already committed via integration), which also reduces their incentive to exercise wholesale market power, thereby further supporting the use of contracts as a risk management device. Furthermore, reduced hold-up risks and greater use of long-term contracts with retail counterparties that are less likely to face financial distress means generators are better able to manage their investment risks, lowering their cost of capital and increasing their access to investment capital. By locking in customers retailers should also be able to enter into less diversified contracts with generators whose capacity better matches their load requirements (e.g. merchant peaking plant), enabling more tailored contracting.

Such measures may be necessary in electricity systems otherwise lacking natural constraints on retail competition (such as transmission constraints), other causes of customer "stickiness", or sources of scarcity rents supporting investment (e.g. as in hydro-exposed systems). However, they appear to be a blunt instrument to achieve the desired end. For example, similar hold-up risks can also arise in respect of large customers operating in competitive output markets (e.g. aluminium smelters), but prescribing entry barriers in such markets would seem an unnecessary and unnatural response to support generation investment. Additionally, the same considerations discussed in relation to regulating for contracting apply, since retaining or reinstating retail franchise areas are examples of such regulation.

Arguments for this approach sit unnaturally alongside the principles underlying electricity sector liberalisation, namely the reliance on competition (in some shape or form) to produce incentives for efficiency gains and to shift risks from customers and taxpayers to investors. Where they rely on contracting supported by franchise areas rather than a combination of endogenous vertical integration and residual contracting they are potentially both unnecessary and just as unsustainable as unsupported contracting, particularly if the well-known incentive problems of franchise areas are not addressed. This approach shifts the problems of risk management into the regulatory domain, which raises its own hold-up risks and hence threats to investment and supply security. If it succeeds, then the risk is that it does so at the undue expense of consumers.

4.2.3 Other Demand-Side Fixes

At least some of the problems presented by contracting can be mitigated by demand-side fixes not requiring constraints on retail competition. In particular, there are long-standing reform areas such as increasing real-time demand-side responsiveness that help to smooth load profiles, reduce demand peaks and uncertainty, mitigate the impacts of generator market power, reduce generation investment needs, and enhance supply security.

If retail customer demand can be better managed so as to avoid peak demands, this reduces the need for often idle peaking generation capacity (and hence also the possible adverse effects of wholesale price regulation and system operating rules on investment). By inducing greater demand-side responsiveness, such as by affording retail customers with options to profit by voluntarily curtailing load during times of peak demand, the transitory exercise of generator market power during times of tight system conditions results in lower welfare loss (Evans and Meade (2005)). Such responsiveness could be achieved either ex ante via load limiting devices (Doorman (2003)), or in real time via retail power exchanges (Evans and Meade (2005)).

By reducing the possible welfare losses from generator market power this also reduces the need for regulatory interventions such as wholesale price caps, and hence supports the lower required levels of capacity investment. In unintegrated systems this should also be reflected in lower retail prices, all other things being equal, thus reducing the need for further retail competition (which would worsen any hold-up risks). Thus a suite of such measures should both reduce contracting costs and improve supply security and investment incentives for any given level of retail competition. Where they are combined with vertical integration this should be more so, and they also should ameliorate concerns that vertical integration creates barriers to retail entry.

Given these considerations we conclude that unless the costs of internal organisation are severe, some form of vertical integration is likely to more naturally dominate in decentralised electricity systems over contracting as a mechanism to manage wholesale price, market power, information asymmetry and investment risks. This leaves complementary roles for spot market and long-term contracting, and de-emphasises hold-up risks from retail entry. As a consequence integrated sectors should be able to sustain greater levels of retail (and industrial customer) competition than de-integrated systems, and better enable the generation investment required for supply security. This implies a reduced role for distortionary regulation and other political interventions, and suggests that the reinstatement or retention of retail franchise monopolies may be unnecessary to ensure supply security, particularly if other system characteristics mean that retail entry is sufficiently deterred or scarcity rents are generated. These implications are explored further in the next section.

5 Discussion and Policy Implications

Decentralised electricity systems have been premised on the efficiency and welfare benefits of competition, and have intentionally shifted investment risks from taxpayers and consumers to investors. Where this coincided with excess capacity in generation, this has supported the evolution of contracts markets and retail entry. However, as capacity margins shrink post-liberalisation, the shortcomings of reliance on contracting – hold-up risks, risk-management mismatches between generators and customers, and market power, asymmetric information and strategic bargaining risks – have become apparent. These shortcomings hinder new investment and threaten the perpetuation of sub-optimal capacity margins. Absent complementary or alternative devices (such as vertical integration, forced contracting or capacity obligations) to compensate for such shortcomings, this threatens supply security and hence the political sustainability of liberalisation, and risks the introduction of destabilising interventions that worsen those shortcomings, or outright recentralisation (e.g. heavy regulation or (re-) nationalisation).

Contracts markets have often arisen more by design than evolution, for example reflecting long-term contracts entered into pre-liberalisation by states with industrial customers. Often they are imposed to facilitate a transition to generator competition while generator dominance is still a concern. Moreover, vertical de-integration has often been a concomitant of horizontal de-integration, artificially (if unintentionally) limiting the role of vertical integration as a risk management device. These have all served to give contracting a prominence that it may not naturally deserve, and eventually highlighted the difficulties in sustaining contracting when those rationales have run their course. This raises the question whether contracting is simply a stepping stone to greater use of vertical integration (or other mechanisms not sharing the shortcomings of contracting).

As such limitations are revealed the liberalisation pendulum appears to be swinging away from pure reliance on contracting in favour of mixed approaches involving either endogenous vertical integration or impositions such as capacity mechanisms. Such a swing coincides with an evolution in the political imperatives surrounding electricity sector liberalisation. Whereas safeguarding consumers against generator market power was commonly a political necessity accompanying any shift towards decentralisation, ensuring supply security – especially in the face of notable reform failures, and even the healthy demise of industry players as part of the competitive process – is increasingly the political priority. Where reformers have retained confidence in decentralised solutions this has involved a tolerance of greater vertical integration. Otherwise it has involved imposed solutions such as capacity obligations, which contain their own inherent shortcomings and hence which may prove to be just as unsustainable as a reliance on contracting (e.g. see Meade (2005)).

Importantly, this evolution requires a re-evaluation of the optimal degree of competition in electricity systems, particularly in retailing. The analysis in this paper stresses that the pursuit of unfettered retail competition – as well as the elimination of other aspects of electricity systems limiting competition (e.g. transmission constraints) – exacerbates hold-up risks, impedes generation investment and hence threatens supply security. Hence textbook pure competition should clearly not be the policy aim. The reinstatement of retail franchise monopolies would appear to be an extreme alternative, however, and may only be justified in the absence of other inherent barriers to retail competition, or by a lack of other system characteristics supporting generation investment. Where such barriers (such as "regionalisation" due to grid constraints) arise, or system characteristics (such as prolonged rather than only transitory price rises as in hydro-exposed systems) otherwise support investment, less extreme levels of retail market power may be sufficient to resolve investment and supply security issues. This is particularly so where systems involve significant degrees of vertical integration to complement or substitute for contracting, in which the hold-up and other risks inherent in contracting are less prominent.

A key challenge for policymakers wishing to stop short of outright reinstatement of retail franchises is to identify the degree of retail market power striking the optimal balance between protecting consumers while maintaining efficient investment incentives. Where those incentives are distorted by interventions such as price caps – particularly in vertically integrated systems where such caps are most likely redundant – the removal of such distortions is an obvious starting point. If there is to be a bias in policymakers' approach, it is likely to best be in favour of supporting investment incentives at the possible risk of short-term retail market power. Policy parameters can then be incrementally refined if it proves that investment incentives are overly generous. The difficulty with the alternative approach is that undue emphasis on controlling retail market power can – and has – resulted in inadequate investment in many systems. The objective should be to encourage desirable long-term decision-making even if this involves short-term biases, since the alternative is to avoid those biases while forestalling or otherwise distorting those long-term decisions. Where other solutions to market power can be implemented without raising retail entry risks – such as measures to improve demand side responsiveness – these are worthy of exploration in their own right. However, they also de-emphasise the importance of retail market competitiveness, and further complement the benefits of vertical integration over contracting in electricity systems.

Abandoning the relentless pursuit of retail market competition involves breaking from one of the important premises of reform – that retail prices will be either reduced or constrained by greater competition over time. Politicians are required to facilitate or allow the emergence of an acceptable level of retail competition, and trust that the decentralised investment signals this produces are sufficient to elicit acceptable generation capacity and supply security. Alternatively, they can substitute for those signals by imposing investment requirements through capacity obligations or otherwise, and in doing so possibly create the need for greater interventions should the signals prove inadequate, particularly given the greater regulatory risks they create. Where limitations have been revealed in designed contracts markets, it should be expected that limitations will also be revealed in alternative imposed approaches. The merit of greater use of vertical integration instead of contracting is that it better insulates electricity systems from their inherent imperfections, as well as from imposed imperfections (e.g. price caps) introduced to address the inherent ones.

Contracting, just like spot markets, continues to play an important role even in vertically integrated systems. Uncertainties in both supply and demand mean integrated generators cannot continuously maintain perfect balance between capacity and embedded load, and hence can integrate only to some degree. Relying simply on spot trading to compensate for any real time imbalances exposes integrated generators to more short-term price volatility than is likely to best enable risk-management over their long-lived generation portfolio. Combining such spot trading with a portfolio of longer-term contracts enables better matching of investment and risk-management maturities for that part of the generator's portfolio that cannot be perfectly balanced through integration. Integration is naturally the dominant risk-management approach where the costs of contracting are large, or simply greater than the costs of internal organisation. Just as competition through market mechanisms is expected to enable lowest-cost generation to displace higher-cost generation, policymakers should anticipate that market mechanisms will also enable the efficient mix of contracting and integration to emerge where each is permitted and not impeded.

There is currently a lack of theoretical work identifying the optimal degree of retail competition that supports efficient investment levels and endogenously-determined optimal supply security. The discussion in this paper presents a natural framework for modelling the optimal use of contracting and integration as a question of mechanism design, given different degrees of retail competition. By incorporating complexities such as industrial/retail mix, industrial customer market power, the impact on retail competition of transmission constraints, demand-side responsiveness and fuel mix and security, it should be possible to demonstrate whether integrated, de-integrated or partially integrated systems can sustain greater levels of retail competition while maintaining investment levels and supply security. This in turn facilitates a dynamic efficiency analysis of the alternatives. Such theoretical modelling is left for future work.

* * *

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Appendix A: Comparison of Selected Electricity Market Structures

	Market structure characteristics	Generation characteristics	Demand characteristics	Trading characteristics
New Zealand *Sources:1, 2a, 2b, 2d*	▪ Generators: 9 total, 5 major (generate over 92% total) ▪ Retailers: major generators are also retailers ▪ Transmission: owned and operated by SOE (Transpower) ▪ Distribution: owned and operated by 28 lines companies ▪ Interconnection: none with other electricity systems	▪ Capacity: 9,000 MW ▪ Production: 42,000 GWh – Hydro 54.9% – Gas 26.4% – Geothermal 7.7% – Coal 6.9% – Wind 2.2% – Others 1.8% ▪ 10% dry year capacity margin ▪ Government Security of Supply policy: will procure Reserve Energy if Winter Energy Margin is forecast to fall below 17% for New Zealand as a whole, or below 30% for the South Island, over the next 3 years; and Winter Capacity Margin is forecast to fall below 780 MW over next 2 years	▪ Consumption: 39,500 GWh – Residential 12,700 – Commercial 9,000 – Industrial 16,800 (including 8,000 from largest customers) – Onsite 1,000 ▪ Peak demand: 6,500 MW	▪ Pricing: nodal ▪ Regulation: wholesale prices uncapped; transmission and distribution (for non-consumer-owned firms) regulated ▪ Energyhedge (anonymous bilateral trading) volume is low (500GWh from 2003-2006) ▪ Approx 70% of total load hedged through vertical integration ▪ "Generators" (incl. gentailers): – avg. load 36,730 GWh – generation 42,022 GWh – hedges sold 10,311 GWh ▪ "Purchasers": – avg. load 11,810 MWh – generation 1,301 GWh – hedges bought 8,100 GWh

	Market structure characteristics	Generation characteristics	Demand characteristics	Trading characteristics
Australia (NEM) *Sources: 3, 5, 2f, 2b, 2d, 4, 8, 6, 7*	▪ Generators: 260 registered (16 major) ▪ Retailers: Full retail competition. 4 retailers have generation interests ▪ Transmission: 5 state-based networks (linked by cross border interconnectors) ▪ Distribution: 13 major networks (open access distribution ▪ Interconnection: only between states. Victoria-Tasmania interconnector constrained	▪ Capacity: 39,400MW ▪ Production: 195,000 GWh – Black coal 59% – Brown coal 25% – Natural gas 8.5% – Hydro 7.2% – Oil + other 0.3% (other includes: biomass, wind power, solar photovoltaic) ▪ Capacity margin: approx 30% ▪ Primary capacity standard based on quantities of expected un-served energy (EUSE) of up to .002% of annual demand	▪ Consumption: – industry 44.6% – residential 27.4% – commercial and public services 26.9% – transport 1.1% ▪ Peak demand: 30,000 MW	▪ Pricing: zonal ▪ Regulation: spot price cap of AUD10,000 per MWh; spot price minimum of AUD-1,000 ▪ Majority (>95%) of standard contracts traded through the use of brokers, with counterparty revealed once contract is struck. The various zones trade 3-4 times the spot trading volumes ▪ Purely cash-settled financial derivatives market, based on fixed for floating swap contracts settled against spot price ▪ Electricity futures contracts are listed on a calendar quarter basis out to 4 years ahead and also trade in 1 year tranches ▪ OTC negotiated constitutes approximately ½ of futures turnover ▪ Contract trade increased to > physical volume in Q1 2007

	Market structure characteristics	Generation characteristics	Demand characteristics	Trading characteristics
United Kingdom: **(NETA/ BETTA)**[15] *Sources: 2e, 2b, 12, 2d*	▪ Generators: 7 major. 50 % of generating capacity owned by gentailers ▪ Retailers: 6 major retailers supply 99% of customers; all. are gentailers ▪ Transmission: owned and operated by National Grid ▪ Distribution: 14 areas operated by 7 licensed companies (must be separate from supply) ▪ Interconnection: limited links with France and Ireland ▪ Market governed by the Balancing and Settlement Code "BSC" Panel, representing generators, retailers, retail customers, Office of Gas and Electricity Markets "OFGEM", National Grid UK "NGUK", distributors and independent advisers	▪ Capacity: 76,000 MW – Coal 35% – Gas 33% – Nuclear 14% – Oil 5% – Peak hydro 4% – Other renewable 3% – Other 3% ▪ Production: 390,000 GWh ▪ Peak reserve margin: 19% ▪ Capacity requirement standard based on a loss-of-load expectation (LOLE) ranging from 2.4 to 8 hours per annum ▪ No complementary mechanisms for capacity adequacy except that system operator can contract for generation reserve if risk identified	▪ Peak demand: 60,000 MW	▪ Pricing: non-locational ▪ Regulation: ▪ Prices set via discriminatory / pay-as-bid auction ▪ UKPX power exchange (incorporating previous APX exchange) is dominant exchange for range of contracts: spot and prompt through to futures and forwards up to 10 seasons out ▪ OTC spot = 11% of consumption; longer OTC contracts (brokered) = 146% ▪ Forward contracts market exhibits reasonable liquidity in contracts up to 12 months, but not longer-term contracts ▪ Nearly 80% of activity is on electronic platforms with the total contracts market size being approximately 4 times the physical market ▪ 5% of total demand traded in balancing mechanism

[15] NETA became BETTA in 2005, when extended to include Scotland

	Market structure characteristics	Generation characteristics	Demand characteristics	Trading characteristics
United States (PJM) *Sources: 2e, 2a*	▪ Generators: all major generators also retailers (but corporate separation required for upstream activities) ▪ Retailers: 350 suppliers ▪ Transmission: Utilities own transmission lines, but transmission lines controlled by ISO ▪ Distribution: utility-owned ▪ Interconnection: 13 States + DC all interconnected ▪ Retail competition differs by state e.g. Pennsylvania forbids long-term bilateral contracts between a load-serving entity and a large industrial customer	▪ Capacity: – Coal 56% – Nuclear 34% – Gas 7% – Oil 0.5% – Renewables 2% (incl. 2% wind) ▪ Production: 700,000 GWh ▪ Capacity margin: 19% ▪ Capacity contracting requirement on all LSEs (PJM requires all retailers to hold a portfolio of installed capacity contracts) + market in which capacity credits can be traded. Significant penalties on LSEs with insufficient credits ▪ Capacity requirement standard based on a loss-of-load expectation (LOLE) ranging from 2.4 to 8 hours per annum	▪ Peak demand: 131,000 MW	▪ Pricing: nodal ▪ Regulation: Consumer tariffs not regulated ▪ Many utilities operating under negotiated generation rate caps for supply services (through to end of 2009/10) ▪ Predominantly OTC market. Some standard contracts through NYPX and Continental electronic exchanges ▪ Voluntary two-tier settlement Day-ahead market with real time balancing. Ex-ante hourly price is a weighted average of five-minute prices. LMP pricing model including congestion only. Reserves scheduled into the real time market and settled at day-ahead clearance prices. Energy offer price cap of $1,000/MWh; Regulation offer price cap of $100/MWh ▪ Mainly bespoke contracts

	Market structure characteristics	Generation characteristics	Demand characteristics	Trading characteristics
United States: (New England - NEPOOL) *Sources:* 10, 12	▪ Generators: 7 major, integrated with retail ▪ Interconnection: between Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont	▪ Capacity: 31,000 MW – Gas CCGT 36% – Oil/gas ST 20% – Nuclear 15% – Coal 9% – Renewable 9% – Oil/gas peaking 6% – Pumped storage 5% ▪ Reserve margin 2007: 18%	▪ Consumption: 135,000 GWh ▪ Peak demand: 28,000 MW	▪ Pricing: locational marginal pricing (an internal hub, eight load zones and more than 500 nodes) ▪ Five markets: – Energy market: two-settlement (day ahead and real-time) spot market – Capacity market – Forward reserves market – Regulation market, and – Financial transmission rights market. FTRs can be acquired in three ways: 1. FTR Auction 2. Secondary Market (ISO-administered bulletin board for bilateral trading) 3. Unregistered Trades. (However, ISO only compensates FTR holders on record)

	Market structure characteristics	Generation characteristics	Demand characteristics	Trading characteristics
Spain *Sources: 13, 8e, 14*	▪ Generators: largest 3 generators (all gentailers) produce 56.4% of energy; 3 next largest produce 11.9%; others produce <2% ▪ Retailers: 3 largest (all gentailers) account for 92.2% of sales ▪ Interconnection: very limited interconnection with France and Portugal – imports total 8,830 GWh (approx 3.5% total consumption) exports 9,860 GWh	▪ Capacity: 78,300 MW – Hydro 21% – CCGT 20% – Coal 15% – Wind 14% – Nuclear 10% – Fuel/gas 8% – Other 12% ▪ Production: 306,400 GWh – CCGT 31% – Coal 24% – Nuclear 18% – Hydro 10% – Wind 9% – Oil 6% ▪ Capacity margin: 86% ▪ Due to strong financial incentives, installed capacity of renewable generation (wind and solar) is rapidly increasing	▪ Consumption: 249,700 GWh – Industry 42.8% – Residential 26.3% – Commercial/other 30.9% ▪ Peak demand: 42,200 MW	▪ Trading platforms: – Bilateral contracting – Futures market – Day-ahead market – Adjustment and balancing markets – AGC market – Reserve markets ▪ Spot traded volume as a percentage of national electricity consumption: 84.02% through OMEL (power exchange), negligible brokered ▪ Through 2005, most trading took place through OMEL because other trades not eligible for capacity payments; rule change has led to decrease in OMEL trading ▪ Relatively small number of market participants accounts for a large part of the overall spot volume traded on both the selling and buying side

	Market structure characteristics	Generation characteristics	Demand characteristics	Trading characteristics
Nordpool *Sources: 2e, 8e, 14*	▪ Interconnection: Norway, Sweden, Denmark, Finland all highly interconnected, but some constraints remain, mostly due to geography ▪ Total imports = 51.3TWh, total exports = 40TWh; Norway and Finland net importers, Sweden and Denmark net exporters ▪ Each country has own retail market and TSO; increasing vertical integration within countries	▪ Production: 400,000 GWh – Thermal 24% – Nuclear 26% – Hydro 48% – Geothermal + other 2% ▪ Generation type varies significantly between countries: Norway predominantly hydro, Finland & Denmark predominantly thermal, Sweden predominantly nuclear ▪ Concern at the lack of generation investment – to the extent that some Norwegian industrial users have decided to invest directly in generation	▪ Consumption: 389,300 GWh ▪ Peak demand: 60,000 MW	▪ Pricing: Elspot sets price based on unconstrained interconnected grid. If constraints, area prices are applied. In 2004, single system price applied for less than 20% of the total hours ▪ Regulation: Hedge market has significant rules, which cover trading, the products that can be listed, and information disclosure (e.g. no insider trading) ▪ 3 voluntary markets: financial derivatives market (Eltermin), a day-ahead spot market (Elspot) and an hour-ahead market (Elbas) ▪ Annual contract trades represent approx 5 times the physical volume of the market ▪ four standard contracts based on system (unconstrained) price: baseload forwards and futures, swaptions & CFD ▪ Approximately 30% of total physical electricity supply and demand is traded through Elspot

	Market structure characteristics	Generation characteristics	Demand characteristics	Trading characteristics
Chile (CDEC) *Sources: 2e*	▪ Interconnection: two interconnected power systems – Central Interconnected System "CDEC-SIC" (coordinates energy for 17 generators and 8 interconnected transmission companies) and System of Norte Grande "CDEC-SING (6 participating generators and 1 transmission company)	▪ Capacity: – CDEC-SIC: 7,000MW – CDEC-SING 3,600MW ▪ Production: 45,000 GWh – Thermal 20% – Hydro 80% ▪ Capacity margin: 27-140% ▪ Capacity payments to generators included in node prices ▪ Operates peak capacity market based on a capacity requirement placed on generators ▪ Additional mechanisms used to ensure system adequacy include: – a) Compensation payments for supply outages – b) Firm capacity transfers – c) Capacity payments – d) Hydro investment incentive	▪ Peak demand: 5,500 MW in CDEC-SIC and 1,500MW in CDEC-SING ▪ Large customers (>0.5MW load) account for 46% total consumption ▪ Large customers (>0.5MW load) enter contracts directly with generators – price not regulated	▪ Pricing: Nodal. Market nodal prices calculated by the market operator include costs of reserves and transmission congestion ▪ Centralised cost-based bidding system where lowest short-run marginal cost generation is dispatched first ▪ Distribution prices set biannually by National Energy Commission (CNE), which also analyses need for new generation capacity ▪ Risk managed largely through OTC contracts and vertical integration. No exchange trading of contracts ▪ Regulation: high degree market regulation

	Market structure characteristics	Generation characteristics	Demand characteristics	Trading characteristics
Argentina (MEM) *Sources: 2e*	▪ Generators: 38 ▪ Retailers: Since 2002, vertical integration has been allowed to increase partly because of the need to improve the financial viability of generating companies. There is now a lot of cross shareholding between generation and distribution/ retail ▪ Transmission: 7 ▪ Distribution: 64 ▪ Interconnection: with Chile, Uruguay, Paraguay and Brazil. In 2003 exports were 2,550GWh and imports 7,600 GWh ▪ 8 energy traders act as load aggregators for large companies (cannot own utilities or assets)	▪ Capacity: 30,000 MW ▪ Production:92,000 GWh – Thermal 52% – Hydro 41% – Nuclear 7% ▪ Capacity margin: 100%	▪ Consumption: 101,000 GWh ▪ Peak demand: approx 15,000 MW ▪ 2308 large consumers ▪ Consumers with annual demand greater than 1 MW can buy and sell in wholesale spot market but must contract for at least 50% of their load ▪ Consumers with demand less than 1MW must contract 100% of their load with a distributor	▪ Pricing: nodal prices include losses, transmission congestion and security costs ▪ Two separate MEM market energy prices calculated by Cammesa: spot and seasonal ▪ Zonal congestion pricing for transmission Regulation: high degree market regulation ▪ Risk managed largely through OTC contracts (approximately 50% of the market), and an increasing amount of vertical integration. No formal exchange for contracts trading ▪ All generating plants required to declare availability in July and December – thermal and nuclear must submit bids for every hour for next six month period. Bids cannot exceed 115% of actual fuel costs but they can be adjusted within the 6-month period if fuel prices fluctuate significantly

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