Memorandum

Date	29 November 2021
To:	Alistair Dixon
From:	Kieran Murray, Toby Stevenson, David Reeve
Re:	**Implications for contract markets of transition toward 100% renewable market**

Introduction

MDAG is developing a problem definition for 100 per cent renewable energy market. This note outlines the implications for contracts markets of the transition toward a 100 per cent renewable energy market.

Approach

Our approach begins from the perspective of transaction cost theories pioneered by Nobel Laureate, Oliver Williamson.[1] This perspective views adapting to disturbances to be a central problem of economic organization. The easier it is for economic actors to adapt to disturbances, the greater the potential for mutual advantage from voluntary exchange. James Buchanan refers to the "mutuality of advantage from voluntary exchange … the most fundamental of all understandings in economics".[2]

Alternative modes of governing exchanges, or transactions, have different strengths and weaknesses in assisting voluntary exchange to adapt to disturbances. For example, spot markets rely primarily on price as a mechanism for communicating information and are well suited to implement autonomous adaption by economic actors but poorly suited to effect cooperative adaptations. Vertical integration, on the other hand, uses conscious, deliberate, and purposeful co-ordination by management hierarchy, but adds bureaucratic costs.

It follows from Williamson's work that it is not particularly useful to think about a sharp dichotomy between spot market transactions and other forms of transactions; rather, there is a continuum of mechanisms or governance arrangements between spot transactions through to bringing activities in-

[1] See for example Williamson, O. E. (1971). *The vertical integration of production: Market failure considerations*. Am.Econ.Rev. 112; (1975). *Markets and hierarchies, analysis and antitrust implications*. New York: The Free Press; (1985). *The economic institutions of capitalism*. New York: Free Press.

[2] Buchanan, J. (2001). *Game Theory, Mathematics, and Economics,* Journal of Economic Methodology, 8 (March): 27-32.

house that offer ways to manage risks. Along this continuum are hybrid forms including various types of financial contacts, long-term power purchasing agreements, joint ventures, and so on.[3]

All of these forms of contracts are incomplete in some way—it is typically impractical or prohibitively costly to write a contract that covers every possible contingency and to stipulate appropriate responses. Because contracts are incomplete, various forms of transaction hazards arise—events may turn out differently than one or both parties expected, one or other party might undertake actions that do not suit the other party after the contract has been agreed, and so on. Different forms of contractual mechanisms along the continuum from spot transactions to vertical integration are more efficient at navigating different manifestations of these real-world imperfections. Economic actors will therefore seek to align governance structures (mechanisms for adaption), which differ in costs and completeness, with transactions, that differ in attributes

Application of our approach

In the table below we assess whether the transition toward a 100% renewable electricity market will increase or decrease reliance on the spectrum of the products and measures for managing risks. The starting point is the wholesale electricity spot market, as it exists, with its detailed code aimed at enabling efficient transactions and its enforcement mechanisms.

To make the analysis tractable, we characterise 11 points along the spectrum of market mechanisms or governance arrangements from spot to vertical integration. In some cases, the products described at these 11 points do not exist or are illiquid; in other cases the products are part of the market today.

For each point on this continuum, we take into account a number of features of the electricity market, thinking about how those features might change during the transition to 100% renewable, and what the likely impact of those changes would be in terms of preferences for the different forms of market mechanism or governance. The features we consider include:

1. The shape of the price duration curve (PDC)
2. Price volatility
3. The ability to forecast prices and value products using historic price data
4. Revenue adequacy for investors
5. Buyer demand for more refined products
6. Willingness for sellers to offer products suited to buyer demand
7. The emergence of flexibility products e.g. distributed energy resources (DER) and batteries.

[3] This view contrasts with earlier conclusions by the Commerce Commission that a derivative contract is a different product from wholesale electricity. However, the prevailing view internationally accepts that derivative contracts are an essential aspect of the relationship between wholesale participants. Compare Commerce Commission, 2009) Investigation report: Commerce Act 1986 S 27, S 30 and S 36 Electricity Investigation, 22 May, p. 44; Australian Gas Light Company v Australian Competition and Consumer Commission (No. 3) [2003] FCA 1525, para 382; Australian Competition Tribunal, Application for Authorisation of Acquisition of Macquarie Generation by AGL Energy Limited [2014] ACompT 1, p.8; Commission of the European Communities, 2010, *Public Consultation by the Directorate General for Energy on measures to ensure transparency and integrity of wholesale markets in electricity and gas: 31 May 2010*, Brussels, p. 2.

For each measure, consideration of the features leads to a narrative about effective management of risks as we transition to a 100 per cent renewable energy market.

What we learn from thinking through the real-world implications for risk management as we transition to 100% renewable

The first key source of uncertainty that emerges from the transition to 100% renewable electricity is the shape of the price duration curve and the level of volatility. Conventional wisdom expects higher frequency of low SRMC based prices, and higher prices when the system is stretched, than is currently the case. The potential for higher prices is controversial because it is yet to be made clear what the opportunity costs of hydro storage releasees will be based on, in the absence of thermal plant in the offer stack.

The second key source of uncertainty arises in the hedge market where the standoff between sellers of hedge products and buyers of hedge products is well documented already. Buyers complain that even if products are available the prices are "too high". Sellers tend to argue that buyers aren't prepared to pay the true value of covering price risk.

Finally, we think about the continuum of products and approaches to risk in the market and see that demand from purchasers for liquidity in existing products may increase especially if volatility rises. Demand for some new products may also come to the fore including more trading in options, more flexibility products and products that are more tailored for buyers' risk management needs. When we use the term demand, we mean greater appetite for those products generally from the buy side. While demand for these products may increase it doesn't automatically follow that supply of those existing or new forms of products will increase commensurately. The sell side's appetite for offering risk management products is mostly concentrated around extracting option premiums to cover fixed costs for low load factor plant or PPAs for merchant generators. We also note that pricing these products will become more difficult as historical prices will be less of a guide given the change to the PDC and volatility as we go towards 100%.

In the table we have stepped through mechanism by mechanism how we think the dynamics may change as we approach 100% renewable generation. That is reflected above as the sources of uncertainty into the future. We have repeated the thought process for two other scenarios; where prices are more explicitly restrained by the Authority and where the Crown enters the market by building generation recommended by the NZ Battery project. We haven't done this to inform the case for or against those eventualities. We introduce them because these scenarios are already in the minds of market participants and should be recognized accordingly. In short, the uncertainties are the same, but the outcomes are different.

Observations of key impacts on the contracts markets

At the present there is an existing distribution of preferences for the mechanisms along the continuum. We know the preferences will be different between the sell side of the market and the buy side of the market. We also know that for both sides the availability, (the liquidity and pricing) of mechanisms is not always fulfilled.

This note is not intended to be analysis of the degree to which participants are satisfied with the availability of risk management options today. In this note we observe that whatever the preference is

for the suite of available (and viable) mechanisms those preferences will change as we progress towards 100% renewable electricity. Further, the preference of those mechanisms will change in each of the two additional scenarios set out in the table.

Generally, we see that the expected increase in volatility and the range of price outcomes from transitioning to 100% renewable would create incentives to move away from spot exposure and move towards the vertical integration end of the spectrum. However, other factors may make vertical integration, and other risk management approaches, unattainable to some participants. Moving to the two alternative scenarios reduces the incentives to vertical integration back to freer trading arrangements, and generally improves access to risk management tools, but increases risks around sole decision-making concentration; this includes potentially inefficient long-run prices discouraging new supply and/or demand.

The designers of the products available include the futures exchange, sellers of products and purchasers who seek particular products. The Authority has a role in what products become more liquid through their rules around market making in certain products. What we learn is that the designers of the contracts and the participants who buy or sell contracts will have to be clear which scenario they are designing for and the consequences if the mix of available mechanisms in each scenario doesn't provide enough ability to manage risks for the market to be able to fulfill its role.

Matrix of possible developments in risk management practices

	1. Transitioning to 100% renewable electricity	2. 100% renewable with restraints on high prices	3. 100% renewable with government entry into the wholesale market
Spot	This row is about whether there is a shift in market participants' preparedness to be exposed to spot prices. If risk is higher demand from purchasers for mechanisms on this table increases although that might take the form of demand for existing products or demand for more tailored products. The converse is that supply of products from existing sources such as stored hydro or new sources such as DER may change as we move through the transition to 100% renewables. In this scenario the PDC changes shape c.f. today resulting from greater frequency and duration of low SRMC type prices, high prices will be higher but less frequent (if there is to be revenue adequacy for investment) plus greater risk of "scarcity" prices per the rules i.e. possible curtailed demand or relaxed n-1. Volatility will increase. During the transition we anticipate lower preparedness to take spot price risk and increased demand for hedge products.	If the Authority were to act in a way that restrained the incidence and level of high prices that would otherwise result from the transition to 100% renewables that might help pricing risk management products but revenue adequacy for investment may be undermined – which could lead to more scarcity over time. On balance, under this scenario the preparedness to take spot price risk will be higher than in scenario 1	In this scenario there might also be a higher preparedness to take spot risk compared to scenario 1 However, the outcome here depends on the governance and operating model of a government owned PHES such as Lake Onslow. If a PHES is in the market continuously (without undermining a DYR objective) price distribution narrows, volatility lessens generally but location risks could still be acute i.e. Auckland and single asset failure (PHES, HVDC, or critical HVAC lines) dependence increases. In this scenario one party now has high influence over price distribution and volatility and, potentially, revenue adequacy. The way it conducts itself will inform the market's preparedness to be exposed to spot prices.

	1. Transitioning to 100% renewable electricity	2. 100% renewable with restraints on high prices	3. 100% renewable with government entry into the wholesale market
Exchange traded CFDs (futures)	In this scenario most futures quarters settle at lower prices than historical trends (because spot price outcomes are lower most of the time) but some quarters will settle at much higher prices. The expected value of any quarter will be significantly higher than the most likely price outcome and more significantly lower than some price outcomes. New market information is likely to swing daily settlement prices dramatically. Variation margins will be quite volatile and higher.[4] Futures prices could be higher to account for the higher cost of holding them Buyer demand for futures could shift to demand for more tailored OTC risk products or new futures specifications.	Against scenario 1 this would mean reduced volatility in futures prices (as a consequence of lower volatility of spot prices) but risk premiums would be expected to be insufficient to cover fixed costs of investments. Variation margin volatility would be less than scenario 1.	This depends on how the Government entity is operated but less volatility in contract prices (as a consequence of less volatility in underlying spot prices) would be likely. This would possibly also lead to arbitrarily lower (or higher) prices, because of pricing behaviour of the Crown plant, meaning prices may be too high or revenue adequacy would be at risk. Variation margin volatility would be less than scenario 1 and could be less than scenario 2.

[4] Initial Margins are set at a level to cover 99.7% of expected daily price movements (where historical movements in daily futures settlement prices are used as a proxy for expected daily price movements). Key to the financial integrity of ASX Clear is the administration of both Initial and Variation Margins that minimise ASX Clear exposure to changes in market prices and counter-party failure. Variation margins are called daily to account for adverse price movement and increases in expected daily price movements

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OTC CFDs	As with trading in futures there may be lower settlement prices in many quarters but much higher prices in some. Demand for contracts tailored to meet purchasers' requirements would increase due to heightened profile risk but it is not clear that there will be higher willingness (or ability) to supply more tailored products. Prices for more tailored products that are offered are likely to be higher than is the case currently. Volatility of settlements increase counter-party credit risks which will likely make OTCs less available to more parties. Importantly, if prices are unconstrainted the long run cost of entry for new generation would be achievable through the spot and forward markets.	As above the demand for risk management products is less than in scenario 1 in this scenario but still higher than is currently the case because of the effect of higher levels of intermittent renewables. Suppliers will be challenged to price risk management products in this scenario but might be more motivated to sell products to lock in firm prices when they can. Critically, in this scenario there is less prospect of long run cost of entry for new investments to be achieved which would have implications for investment levels and, ultimately adverse impact on prices. Credit risks would be less than in scenario 1 but expectations of price between sellers, seeking to recover fixed and non-cash costs, will diverge further from buyers, whose counterfactual is lower spot prices. The parties will be less likely to agree on the risk premium.	Credit conditions would ease under this scenario compared to scenario 1, and maybe scenario 2, but prices could be arbitrarily higher or lower than efficient (lowest price sufficient to ensure investment). Contract price expectations are likely to diverge between buyers and sellers as in scenario 2.

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OTC options	Buyer demand goes up for OTC options in this scenario but preparedness to pay the premium is still as reluctant as ever Won't have a relevant history of prices which will make it harder to value (esp. for sellers). i.e. the standoff between buyer and seller perception of value becomes more acute Credit terms are also likely to be a barrier to contracting for some parties	With a lower distribution of prices i.e. less volatility, the standoff on price might be less but buyer demand for options falls. There may be fewer sellers based on a perception they only get the opportunity to 'lock in losses'. Therefore, the standoff might not improve. Contract price expectations are likely to diverge between buyers and sellers as they do for OTC CFDs. Credit terms could be less acute than scenario 1	As with scenario 2, with a lower distribution of prices i.e. less volatility, the standoff might be less but buyer demand for options. There may also be fewer sellers on the basis that they only get the opportunity to 'lock in losses'. Therefore, the standoff might not improve. Contract price expectations are likely to diverge between buyers and sellers as they do for OTC CFDs. Credit terms could be less acute than both other scenarios
Exchange traded options	The historically low uptake of exchange trade options could be exacerbated with shift to greater buyer demand for tailored products. Currently exchange traded options are options on futures, which is a 'swaption' like arrangement. Preferences are likely to be for tailored OTC products (e.g. load following) or options with different specifications (e.g. traditional caps).	The pricing, standoff, and buyer demand changes compared with scenario 1 as per OTC options, which makes exchange traded options even less likely to trade than in scenario 1.	The pricing, standoff, and buyer demand changes as per OTC options, which makes exchange traded options even less likely to trade than in scenario 1.

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Load following hedges	There would be greater buyer demand for LFH but possibly less willingness to supply. With more intermittent generation offsetting thermal then there is less flexible generation available. To make load following product available flexible products need to be added to renewable sources of supply to match a demand profile. There is a possible emergence of flexibility providers (DER, batteries etc.) but reluctance to pay for tail/flex risk management products may also limit the emergence of these products. In the case of DER if other value streams aren't available (e.g. T&D alternatives) there may be reduced supply.	There would be less buyer demand for LFH than in scenario 1. However, with muted peak signals then there is less likelihood of flexibility providers emerging. With large amounts of intermittent renewable generation then demand of LFH is still likely to exceed supply. Price standoffs may be more acute in this scenario, as expected for other contract arrangements.	It would depend on how the government owned facility was operated but there would probably be less buyer demand for LFH under this scenario – buyers will be better able to use fixed volume contracts with less risk on unders and overs. Depending on the location and/or diversity of the government owned facility there could be higher demand for location products (i.e. to Auckland/UNI) or greater demand for location specific LFH. Depending on local price outcomes and how much the government facility affects perceptions of investor risk then flexibility providers may or may not emerge.
DY products	It must be the case that there would be higher buyer demand for DY products because of the risk of sustained high prices in this scenario. Products may emerge but the challenge of valuing dry year risk arises and the willingness to make products avaible is unlikely to be higher than is currently the case.	Less likely for buyer demand and products to emerge in this scenario c.f. scenario 1	In this scenario the demand for DY products reduces although there may be some demand for NI orientated DY and peak products if the solution is SI PHES.
Peak products	Greater demand. Possible emergence of flexibility providers (DER, batteries etc.).	With muted peak signals less likelihood of flexibility providers emerging	Less demand for flexibility providers based on price but greater demand for flexibility products in the NI (if the intervention is south of Whakamaru, especially if SI based))

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Combination fixed volume products and flexibility arrangements	This is the possibility that new hybrid products emerge from the sell side that combine traditional hedge products with new approaches to managing stored hydro or DER with caps. If price discovery is unfettered and price volatility increases a market for more sophisticated OTC products could emerge. However, this requires greater trading sophistication and for parties to be able to agree on price.	The hybrid baseload and flexibility arrangements are less likely to emerge in scenario 2.	The hybrid baseload and flexibility arrangements are not likely to emerge in scenario 3. Depending on the location and diversity of a government facility, there could be buyer demand for them in the UNI but sophisticated products are less likely to emerge in a smaller market.
PPAs	For generation counterparties with intermittent generation with no accompanying flex arrangements there would be increasingly less buyer demand for their PPAs (or willingness to pay). At issue is the ability to match generation volume with load.	At the margin PPAs might be more desirable for purchasers but in the longer run there is less likelihood of the emergence of flexibility products in this scenario c.f. scenario 1	PPAs might grow in this scenario with less anxiety about the need for accompanying flexibility products. PPAs with flexibility may still have a role for some locations.
Vertical integration (VI) (includes JVs)	The value in VI focuses more on generation that matches load shape or is discretionary so incentive for VI increases in this scenario but not VI with intermittent generation unless matched with flexibility products	No higher incentive to vertically integrate than scenario 1	Lower incentive to vertically integrate than in scenario 1